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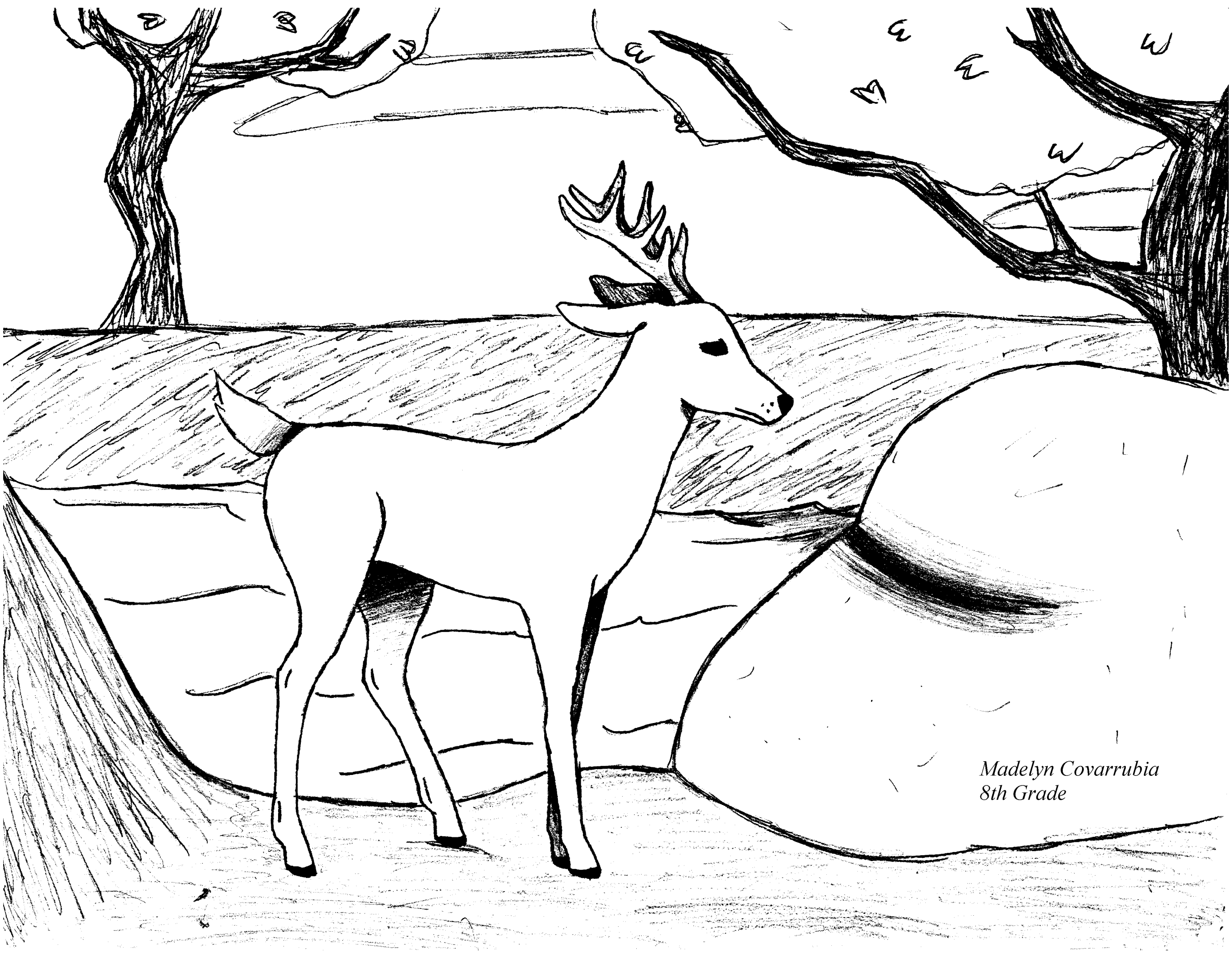

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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TRD-200606737
Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
Earliest possible date of adoption: January 28, 2007
For further information, please call: (512) 239-6087

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CHAPTER 117. CONTROL OF AIR POLLUTION FROM NITROGEN COMPOUNDS

The Texas Commission on Environmental Quality (TCEQ or commission) proposes the repeal of §§117.10, 117.101, 117.103, 117.105 - 117.111, 117.113 - 117.117, 117.119, 117.121, 117.131, 117.133 - 117.135, 117.138, 117.139, 117.141, 117.143, 117.145, 117.147, 117.149, 117.151, 117.201, 117.203, 117.205 - 117.211, 117.213 - 117.217, 117.219, 117.221, 117.223, 117.260, 117.261, 117.265, 117.273, 117.279, 117.283, 117.301, 117.305, 117.309, 117.311, 117.313, 117.319, 117.321, 117.401, 117.405, 117.409, 117.411, 117.413, 117.419, 117.421, 117.451, 117.455, 117.458, 117.460, 117.461, 117.463, 117.465, 117.467, 117.469, 117.471, 117.473, 117.475, 117.478, 117.479, 117.481, 117.510, 117.512, 117.520, 117.524, 117.530, 117.534, 117.570, and 117.571. The commission also proposes new §§117.10, 117.100, 117.103, 117.105, 117.110, 117.115, 117.123, 117.125, 117.130, 117.135, 117.140, 117.145, 117.150, 117.152, 117.154, 117.156, 117.200, 117.203, 117.205, 117.210, 117.215, 117.223, 117.225, 117.230, 117.235, 117.240, 117.245, 117.252, 117.254, 117.256, 117.300, 117.303, 117.305, 117.310, 117.315, 117.320, 117.323, 117.325, 117.330, 117.335, 117.340, 117.345, 117.350, 117.352, 117.354, 117.356, 117.400, 117.403, 117.410, 117.423, 117.425, 117.430, 117.435, 117.440, 117.445, 117.450, 117.454, 117.456, 117.1000, 117.1003, 117.1005, 117.1010, 117.1015, 117.1020, 117.1025, 117.1035, 117.1040, 117.1045, 117.1052, 117.1054, 117.1056, 117.1100, 117.1103, 117.1105, 117.1110, 117.1115, 117.1120, 117.1125, 117.1135, 117.1140, 117.1145, 117.1152, 117.1154, 117.1156, 117.1200, 117.1203, 117.1205, 117.1210, 117.1215, 117.1220, 117.1225, 117.1235, 117.1240, 117.1245, 117.1252, 117.1254, 117.1256, 117.1300, 117.1303, 117.1310, 117.1325, 117.1335, 117.1340, 117.1345, 117.1350, 117.1354, 117.1356, 117.2000, 117.2003, 117.2010, 117.2025, 117.2030, 117.2035, 117.2045, 117.2100, 117.2103, 117.2110, 117.2125, 117.2130, 117.2135, 117.2145, 117.3000, 117.3003, 117.3005, 117.3010, 117.3020, 117.3025, 117.3035, 117.3040, 117.3045, 117.3054, 117.3056, 117.3100, 117.3101, 117.3103, 117.3110, 117.3120, 117.3123, 117.3125, 117.3140, 117.3142, 117.3145, 117.3200, 117.3201, 117.3203, 117.3205, 117.3210, 117.3215, 117.3300, 117.3303, 117.3310, 117.3325, 117.3330, 117.3335, 117.3345, 117.4000, 117.4005, 117.4025, 117.4035, 117.4040, 117.4045, 117.4050, 117.4100, 117.4105, 117.4125, 117.4135, 117.4140, 117.4145, 117.4150, 117.4200, 117.4205, 117.4210, 117.8000, 117.8010, 117.8100, 117.8110, 117.8120, 117.8130, 117.8140, 117.9000, 117.9010, 117.9020, 117.9030, 117.9100, 117.9110, 117.9120, 117.9130, 117.9200, 117.9210, 117.9300, 117.9320, 117.9340, 117.9500, 117.9800, and 117.9810. The repeals and new sections of Chapter 117 will be submitted to the United States Environmental Protection Agency (EPA) as a revision to the state implementation plan (SIP).

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE PROPOSED RULES

GENERAL BACKGROUND

The commission is proposing to repeal 30 TAC Chapter 117, Control of Air Pollution from Nitrogen Compounds, in its entirety and proposes a new reformatted Chapter 117. This proposed repeal and reformatting of Chapter 117 is necessary to accommodate new proposed rules for the eight-hour ozone attainment demonstration and to provide for future potential rulemakings. The proposed rules retain current one-hour ozone rules for all ozone attainment and nonattainment areas of the state. Further background information on the existing Chapter 117 one-hour ozone rules may be found in previous amendments to Chapter 117. In addition to the proposed reformatting of Chapter 117, the proposed rulemaking would implement requirements of House Bill (HB) 965. During the 79th Legislature, 2005, the Texas Legislature adopted HB 965, requiring the commission to conduct a study to determine the technical and economic feasibility of regulating residential water heaters. If the study indicates that regulating residential water heaters is technically or economically infeasible, HB 965 requires that the executive director recommend to the commission that the rules be repealed no later than December 31, 2006.

This proposed rulemaking also includes proposed new rules that are part of the commission's control strategy for the Dallas-Fort Worth eight-hour nonattainment area to attain the eight-hour ozone national ambient air quality standards (NAAQS) and are a part of the eight-hour attainment demonstration SIP revision for the Dallas-Fort Worth eight-hour nonattainment area. The rules proposed in this rulemaking would require emission reductions that are necessary in order for the Dallas-Fort Worth eight-hour nonattainment area to make progress toward, attain, and maintain the eight-hour ozone NAAQS.

The Federal Clean Air Act (FCAA) Amendments of 1990, as codified in 42 United States Code (USC), §§7401 *et seq.,* require EPA to set NAAQS to ensure public health and to designate areas as either in attainment or nonattainment with the NAAQS, or as unclassifiable. States are primarily responsible for ensuring attainment and maintenance of the NAAQS once established by EPA. Each state is required to submit a SIP to the EPA that provides for attainment and maintenance of the NAAQS.

The Dallas-Fort Worth area, consisting of four counties (Collin, Dallas, Denton, and Tarrant), was designated nonattainment and classified as moderate for the one-hour ozone NAAQS in accordance with the 1990 FCAA Amendments. The area was required to attain the one-hour ozone NAAQS by November 15, 1996. A SIP was submitted based on a volatile organic compound (VOC) reduction strategy, but the Dallas-Fort Worth area did not attain the NAAQS by the mandated deadline. Consequently, in 1998 the EPA reclassified the Dallas-Fort Worth area from "moderate" to "serious," resulting in a requirement to submit an additional SIP revision demonstrating attainment by the new deadline of November 15, 1999.

The Dallas-Fort Worth area also failed to reach attainment by the November 15, 1999, deadline. In the attainment demonstration SIP revision adopted by the commission in April 2000, the importance of local nitrogen oxides (NO_x) reductions as well as the transport of ozone and its precursors from the Houston-Galveston-Brazoria ozone nonattainment area were considered. Based on photochemical modeling demonstrating transport from the Houston-Galveston-Brazoria area, the agency requested an extension of the Dallas-Fort Worth area attainment date to November 15, 2007, the same attainment date as for the Houston-Galveston-Brazoria area, in accordance with an EPA policy allowing extension of attainment dates due to transport of pollutants from other areas.

The EPA transport policy was later overturned by three federal courts, including the Court of Appeals for the 5th Circuit, which ruled in *Sierra Club et. al v. EPA,* 314 F. 3d 735 (2002) that EPA did not have authority to extend an area's attainment date based on transport. Although the Dallas-Fort Worth area was not the specific subject of any of these suits, the Dallas-Fort Worth area one-hour ozone attainment demonstration SIP, including an extended attainment date, was not approvable by EPA.

On July 18, 1997, EPA promulgated a revised ozone standard (the eight-hour ozone NAAQS), (62 FR 38856). The eight-hour ozone NAAQS was challenged by numerous litigants and ultimately upheld by the United States Supreme Court in February 2001. On April 30, 2004, EPA promulgated the first phase of the implementation rules for the eight-hour ozone NAAQS (Phase I Implementation Rule) (69 FR 23951). Also on April 30, 2004, the Dallas-Fort Worth area was designated as nonattainment and classified as moderate for the eight-hour ozone NAAQS. Five additional counties (Ellis, Johnson, Kaufman, Parker, and Rockwall) were added to the Dallas-Fort Worth eight-hour ozone nonattainment area. Effective June 15, 2004, nine counties (Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant) in the Dallas-Fort Worth area are nonattainment for the eight-hour ozone NAAQS. The Dallas-Fort Worth eight-hour nonattainment area must attain the eight-hour ozone NAAQS by June 15, 2010.

EPA's Phase I Implementation Rule provided three options for eight-hour ozone nonattainment areas that do not have an approved one-hour ozone attainment SIP: 1) submit a one-hour ozone attainment demonstration; 2) submit an eight-hour ozone attainment providing for a 5% increment of progress (IOP) emission reductions from the area's 2002 emissions baseline that is in addition to federal and state measures already approved by EPA and achieves these reductions by June 15, 2007; or 3) submit an eight-hour ozone attainment demonstration. The due date for any option selected was June 15, 2005, one year after designation. The commission, in consultation with EPA, determined that option two was the most expeditious approach to beginning to achieve the emission reductions ultimately needed to meet the June 15, 2005, transportation conformity deadline and attain the eight-hour ozone NAAQS by June 15, 2010. Therefore, the commission adopted a 5% IOP Plan in April 2005 and submitted it to EPA. On November 29, 2005, EPA subsequently finalized its Phase II Implementation Rule for the eight-hour ozone NAAQS (Phase II Implementation Rule) (70 FR 71612). The Phase II Implementation Rule provides guidance and requirements for the remaining elements of the program to implement the eight-hour ozone NAAQS.

The emission reduction requirements from this proposed rulemaking, if adopted, would result in reductions in ozone formation in the Dallas-Fort Worth eight-hour nonattainment area and help bring the area into compliance with the eight-hour ozone NAAQS. The proposed compliance date for implementing control requirements and emission reductions for the Dallas-Fort Worth eight-hour ozone attainment demonstration is March 1, 2009. The commission is requesting comments regarding the technical feasibility of installing controls as well as the availability of vendors and control equipment by March 1, 2009. In addition, the commission is soliciting comments on alternative compliance implementation schedules, such as a phased compliance based on unit size or age.

CHAPTER 117 REFORMAT

The commission is proposing to repeal Chapter 117, Control of Air Pollution from Nitrogen Compounds, in its entirety and proposes a new reformatted Chapter 117. This proposed repeal and reformatting of Chapter 117 is necessary to accommodate new proposed rules for the Dallas-Fort Worth eight-hour ozone attainment demonstration and to provide for future potential rulemaking. The commission is not soliciting comments on sections proposed only for reformatting, unless otherwise specified in the SECTION BY SECTION DISCUSSION section of this preamble. Some minor technical changes and corrections to existing language for rule language associated with the one-hour ozone NAAQS are proposed and are discussed in detail in the SECTION BY SECTION DISCUSSION section. The commission is accepting comments on these specific proposed minor changes and on new rules associated with the eight-hour ozone attainment demonstration for the Dallas-Fort Worth eight-hour ozone nonattainment area. Comments received regarding sections and rule language associated only with reformatting and minor stylistic changes will not be considered and no changes will be made based on such comments, unless the comment is in regard only to how the language is reformatted. The specific portions of Chapter 117 that the commission will consider comments on are included in the following list.

Figure 1: 30 TAC Chapter 117--Preamble

Proposed subchapters, divisions, and key sections with new requirements or modifications associated with the Dallas-Fort Worth eight-hour ozone attainment demonstration include: Subchapter A, Definitions, §117.10; Subchapter B, Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Nonattainment Areas, Division 4, Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources, §§117.400, 117.403, 117.410, 117.423, 117.425, 117.430, 117.435, 117.440, 117.445, 117.450, 117.454, and 117.456; Subchapter C, Combustion Control at Major Utility Electric Generation Sources in Ozone Nonattainment Areas, Division 4, Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources, §§117.1300, 117.1303, 117.1310, 117.1325, 117.1335, 117.1340, 117.1345, 117.1350, 117.1354, and 117.1356; Subchapter D, Combustion Control at Minor Sources in Ozone Nonattainment Areas, Division 2, Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources, §§117.2100, 117.2103, 117.2110, 117.2125, 117.2130, 117.2135, and 117.2145; Subchapter E, Multi-Region Combustion Control, Division 2, Cement Kilns, §§117.3103, 117.3123, 117.3125, 117.3142, and 117.3145; Subchapter E, Multi-Region Combustion Control, Division 4, East Texas Combustion, §§117.3300, 117.3303, 117.3310, 117.3325, 117.3330, 117.3335, and 117.3345; and Subchapter H, Administrative Provisions, Division 1, Compliance Schedules, §§117.9030, 117.9130, 117.9210, 117.9320, and 117.9340.

Demonstrating Noninterference under Federal Clean Air Act, Section 110(l)

The commission provides the following information to clarify that the repeal and reformatting of 30 TAC Chapter 117 will not negatively impact the status of the state's attainment and maintenance of the ozone NAAQS. All existing rules remain effective until the effective date of the proposed reformatted 30 TAC Chapter 117, if adopted. All requirements in the existing rules for the one-hour ozone NAAQS, applicable to a particular region or area that the rule applies to, have been incorporated into the proposed new formatted rules. As noted previously in this preamble, the proposed repeal and reformatting is necessary to accommodate new rules. Other minor technical changes and corrections do not affect the stringency or enforceability of the rules. Therefore, there will be no backsliding or temporary lapse in the enforcement or effectiveness of the current requirements in 30 TAC Chapter 117.

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

DIVISION 4: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MAJOR SOURCES

The commission is proposing a new Subchapter B, Division 4, entitled Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources, with new emission control requirements for major industrial, commercial, or institutional (ICI) sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area. This proposed rulemaking is a part of the Dallas-Fort Worth eight-hour ozone attainment demonstration and the emission reductions associated with this rulemaking would help bring the Dallas-Fort Worth eight-hour ozone nonattainment area into compliance with the eight-hour ozone NAAQS.

The proposed addition of Subchapter B, Division 4 would require owners or operators of major ICI sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area to reduce NO_x emissions from a wide variety of stationary sources. A major source NO_x in Dallas-Fort Worth eight-hour ozone nonattainment area is any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit equal to or greater than 50 tons per year (tpy) of NO_x. The stationary source type categories with proposed controls in the rulemaking include the following: ICI boilers and gas turbines; duct burners used in turbine exhaust ducts; process heaters and furnaces; stationary internal combustion engines; brick, ceramic, and lime kilns; metallurgical heat treating and reheat furnaces; electric arc furnaces used in steel production; lead smelting blast (cupola) and reverberatory furnaces; glass melting furnaces; fiberglass and mineral wool fiber melting furnaces; fiberglass and wool fiber curing and forming ovens; heaters and ovens, and dryers used in organic solvent, printing ink, and ceramic tile, clay, and brick drying, and calcining and vitrifying; and incinerators. The proposed emission specifications for some of these source categories are consistent with the current emission specifications effective in the Houston-Galveston-Brazoria ozone nonattainment area. New emission specifications are proposed for certain source categories in the Dallas-Fort Worth eight-hour ozone nonattainment area, for which there are currently no emission specifications established in Chapter 117 for any ozone nonattainment area. These source categories proposed to be newly regulated under Chapter 117 include: brick and ceramic kilns; electric arc furnaces used in steel production; lead smelting blast (cupola) and reverberatory furnaces; heaters, ovens, and dryers; and glass, fiberglass, and mineral wool melting furnaces and curing and forming ovens.

Proposed new Subchapter B, Division 4 also includes monitoring, testing, recordkeeping, reporting, and other requirements associated with the proposed emission specifications necessary to ensure compliance with the emission specifications and to ensure that the necessary NO_x emission reductions are achieved. Specific discussion associated with the proposed emission specifications and other requirements in proposed new Subchapter B, Division 4 is provided in the SECTION BY SECTION DISCUSSION section.

The commission estimates that this proposed rule would result in a 12.7 tons per day (tpd) reduction of NO_x from major ICI sources in the Dallas-Fort Worth eight-hour ozone nonattainment area, based on 2009 future case modeling. The emission reductions that would result from this proposed rulemaking, if adopted, would result in reductions in ozone formation in the Dallas-Fort Worth eight-hour ozone nonattainment area, and help bring the Dallas-Fort Worth eight-hour ozone nonattainment area into compliance with the eight-hour ozone NAAQS. These emission reductions are one component of the Dallas-Fort Worth attainment demonstration SIP revision that the state is required to submit to EPA to assure attainment and maintenance of the eight-hour ozone NAAQS. The proposed new rules in Subchapter B, Division 4 are one step toward meeting the state's obligations under the FCAA.

Sections 182(b)(2) and 182(f) of the FCAA require implementation of reasonably available control technology (RACT) for major sources of NO_x covered by the Alternative Controls Techniques (ACT) documents for ozone nonattainment areas classified as moderate and above. The existing Chapter 117 NO_x rules associated with the one-hour ozone NAAQS contain a specific section, existing §117.205, for RACT emission specifications for these unit types. These existing RACT requirements for the four-county Dallas-Fort Worth ozone nonattainment area are retained in the reformatted Chapter 117 and are proposed to be incorporated in a proposed new §117.205. For the Dallas-Fort Worth eight-hour ozone nonattainment area, the commission is not proposing to expand the applicability of proposed new §117.205 to the nine-county area. Furthermore, the proposed new Subchapter B, Division 4 does not include an equivalent NO_x RACT section for the Dallas-Fort Worth eight-hour ozone nonattainment area. The emission specifications in proposed new §117.410 that are necessary for the Dallas-Fort Worth eight-hour ozone attainment demonstration are equivalent or stricter NO_x emission specifications than would be under RACT for all unit and industry types specified in the EPA ACT documents for those industries in the Dallas-Fort Worth eight-hour nonattainment area. The commission therefore considers the FCAA NO_x RACT requirement fulfilled by the emission specifications for attainment demonstration proposed in §117.410 for the Dallas-Fort Worth eight-hour ozone nonattainment area.

SUBCHAPTER C: COMBUSTION CONTROL AT MAJOR UTILITY ELECTRIC GENERATION SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 4: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

The commission is proposing a new Subchapter C, Division 4, entitled Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources, with new requirements for utility electric generation sources in the Dallas-Fort Worth eight-hour ozone nonattainment area. Proposed new Subchapter C, Division 4 would apply to utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in turbine exhaust ducts used in an electric power generating system owned or operated by a municipality or a PUC-regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC; or an electric cooperative, independent power producer, municipality, river authority, or public utility located within the Dallas-Fort Worth eight-hour ozone nonattainment area. The proposed rule establishes a unit-by-unit approach for compliance with the existing emission specifications for units subject to the proposed rule. The proposed rule also provides a new efficiency, or output-based, emission specification as an option for utility boilers. This proposed new rule for electric generating units for the Dallas-Fort Worth eight-hour attainment demonstration would retain the existing heat input-based emission specifications; however, the proposal would not allow alternative system-wide emission specifications or system cap options as alternative means of compliance. Under the proposal, affected units would be required to comply with the proposed emission specifications on a unit-by-unit basis. The commission estimates that this proposed rule would result in approximately 2 tpd NO_x reductions from major utility electric generation sources in the Dallas-Fort Worth eight-hour ozone nonattainment area, based on 2009 future case modeling.

In addition, to satisfy RACT requirements for the five new counties, the existing RACT emission specifications for auxiliary steam boilers and stationary gas turbines from existing §117.105, applicable in the four-county Dallas-Fort Worth ozone nonattainment area, are proposed as emission specifications for attainment demonstration for the nine-county Dallas-Fort Worth eight-hour ozone nonattainment area. The commission is not proposing to change these RACT emission specifications; however, under this proposed rule, owners or operators would not be able to use the system cap or alternative system-wide emission specifications for compliance with the RACT emission specifications.

Specific discussion associated with the proposed specifications and other requirements in proposed new Subchapter C, Division 4 is provided in the SECTION BY SECTION DISCUSSION section. The emission reduction requirements that would result from this proposed rulemaking, if adopted, would help bring the Dallas-Fort Worth eight-hour ozone nonattainment area into compliance with the eight-hour ozone NAAQS. These emission reductions are one component of the Dallas-Fort Worth attainment demonstration SIP revision that the state is required to submit to EPA to assure attainment and maintenance of the eight-hour ozone NAAQS. The proposed new rules in Subchapter C, Division 4 are one step toward meeting the state's obligations under the FCAA.

SUBCHAPTER D: COMBUSTION CONTROL AT MINOR SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 2: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MINOR SOURCES

The commission is proposing a new Subchapter D, Division 2, entitled Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources, with new requirements for minor stationary sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area. The existing Subchapter D, Division 2, is proposed to be reformatted as a new Subchapter D, Division 1, entitled Houston-Galveston-Brazoria Ozone Nonattainment Area Minor Sources. This proposed rule supports the Dallas-Fort Worth eight-hour ozone nonattainment area attainment demonstration by requiring a variety of stationary sources of NO_x emissions in the Dallas-Fort Worth eight-hour ozone nonattainment area to meet new emission specifications and other reductions of NO_x emissions. Because of the large amounts of NO_x reductions necessary to attain the NAAQS, all reasonable control strategies to achieve NO_x reductions must be pursued. This proposed rulemaking would require owners or operators of minor sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area to reduce NO_x emissions from affected boilers, process heaters, stationary internal combustion engines, and gas turbines (including duct burners). A minor source NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area is any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit less than 50 tpy of NO_x.

This proposed rulemaking would regulate units at sites including small businesses and industries, hospitals, hotels, public and private office and administrative buildings, and school districts that were previously unregulated. Based on analysis of the available information, the commission estimates that this proposed rule would result in approximately 4.5 tpd in NO_x emission reductions, based on 2009 future case modeling. For modeling purposes, these emission reductions would be accounted for in the area source inventory.

SUBCHAPTER E: MULTI-REGION COMBUSTION CONTROL

DIVISION 2: CEMENT KILNS

On April 22, 2005, a settlement agreement was entered into by the TCEQ and Blue Skies Alliance, *et al.*, to resolve a lawsuit brought by the Blue Skies Alliance, *et al.*, against the EPA (2004). The settlement agreement required the commission to conduct a study of technologies for controlling NO_x emissions from cement kilns, in consultation with the parties to the settlement. The report, entitled *Assessment of NO_x Emissions Reduction Strategies for Cement Kilns--Ellis County: Final Report*, was submitted to the TCEQ on July 14, 2006, and is available on the commission's Web site at *www.tceq.state.tx.us/implementation/air/sip/BSA_settle.html.*

The study evaluated the applicability, availability, and cost-effectiveness of potential NO_x control technologies for cement kilns located in the Dallas-Fort Worth eight-hour ozone nonattainment area that could provide additional NO_x reductions beyond the requirements of Chapter 117 in effect in 2006. The report primarily focused on three active types of control technologies for cement kilns: selective catalytic reduction (SCR), selective noncatalytic reduction (SNCR), and low temperature oxidation (LoTOx). Based on the results of this study, the commission conducted modeling sensitivity studies for two levels of control to evaluate the potential ozone reduction benefit from possible cement kiln control strategies. The first control level modeling run was performed based on 35 - 50% control, and the second control level modeling run was performed based on 80 - 85% control.

After reviewing the final report of the control technology study, modeling sensitivity run results, and other available information, the commission has determined that the 35 - 50% control level is the most appropriate control level that can reasonably be in place by the 2009 ozone season for this proposed rulemaking. This control level is based on using SNCR controls on cement kilns. SNCR control technology is applicable to both dry preheater-precalciner or precalciner kilns and long wet kilns. While SCR and LoTOx control technologies may be applicable to cement kilns, these control technologies are not as well established for cement kilns as SNCR control.

To implement this control strategy, the commission is proposing a source cap approach to establish a maximum NO_x emission cap for each account. This approach provides flexibility for owners or operators to achieve the reductions modeled for this control strategy. A source cap allows an owner or operator to choose the most applicable and cost-effective control technology available to a particular kiln while still achieving the overall reductions modeled for the Dallas-Fort Worth eight-hour attainment demonstration. Owners or operators may use any applicable control technologies to achieve reductions for compliance with the source cap. In addition, the intent of the source cap approach is to establish a maximum cap on the total NO_x emissions from cement kilns at each account based on the number of kilns in operation in calendar year 2000. The provisions of the proposed new rule would prohibit expanding the source cap based on new units installed after calendar year 2000. Before an increase in NO_x emissions from a change in operation from one unit or the installation of a new kiln could occur, a corresponding decrease in NO_x emissions would be required from another existing unit, unless the account's NO_x emissions were already sufficiently below the source cap.

Compliance with the proposed source cap would be on a 30-day rolling average basis. The 30-day rolling average basis for the source cap provides flexibility to account for the inherent variability in NO_x emissions from cement kilns. Owners or operators would demonstrate compliance with the source cap using new monitoring, testing, reporting, and recordkeeping requirements in the proposed rule, as described elsewhere in this preamble. The commission estimates that this proposed rule would result in approximately 11.0 tpd in NO_x emission reductions, based on 2009 future case modeling. The commission is soliciting comment on the proposed source cap approach, particularly regarding the economic and technical feasibility of the approach.

DIVISION 3: WATER HEATERS, SMALL BOILERS, AND PROCESS HEATERS

On April 19, 2000, the commission adopted rules, published in the May 5, 2000, issue of the *Texas Register* (25 TexReg 4101), that require water heaters, small boilers, and process heaters statewide to meet specific NO_x emission specifications. These rules were part of a SIP control strategy for attainment with the ozone NAAQS.

Under the adopted rules, manufacturers, distributors, retailers, and installers of natural gas-fired water heaters with a maximum rated capacity of no more than 75,000 British thermal units per hour (Btu/hr), designated as a Type 0 unit in the adopted rules, were required to meet the emission specifications in §117.465. Specifically, Type 0 units manufactured, distributed, sold, or installed on or after July 1, 2002, but no later than December 31, 2004, were required to meet a 40 nanogram per joule (ng/J) heat output limit. Type 0 units manufactured, distributed, sold, or installed on or after January 1, 2005, were required to meet a 10 ng/J heat output limit.

Type 0 units that meet the 40 ng/J emission standard have been developed and made available by manufacturers. However, in a rulemaking effective December 23, 2004, the commission proposed a one-year delay for conventional Type 0 water heaters with a capacity equal to or less than 50 gallons, and a two-year delay for conventional Type 0 water heaters with a capacity that exceeds 50 gallons, to meet the 10 ng/J emission standard. Subsequent to the initiation of the rulemaking proposal, the commission received a petition from the Gas Appliance Manufacturers Association (GAMA) on June 22, 2004, regarding the water heater rules. GAMA petitioned the commission to adopt a rule that would amend §117.465 to delay implementation of the 10 ng/J NO_x emission limit for some categories of gas water heaters and to provide an exclusion for two other specific categories of water heaters. For conventional water heaters with storage volumes of 50 gallons or less, the petitioner requested a delay in the implementation of the 10 ng/J NO_x emission limit from January 1, 2005, to January 1, 2006. For conventional water heaters with storage volumes greater than 50 gallons, the petitioner requested a delay in the implementation of the 10 ng/J NO_x emission limit from January 1, 2005, to January 1, 2007. Based on the comments received and uncertainties of equipment manufacturers' ability to meet the Type 0 emission standards, the commission adopted a rule revision to allow a two-year delay for all conventional Type 0 units.

During the 79th legislative session, the Texas Legislature adopted HB 965, requiring the commission to conduct a study to determine the technical and economic feasibility of regulating residential water heaters. According to HB 965, if the study indicates that regulating residential water heaters is technically or economically infeasible, the executive director shall recommend to the commission that the rules be repealed no later than December 31, 2006. Residential water heaters are currently regulated by 30 TAC Chapter 117, Subchapter D, Division 1. Section 117.465(b)(2) establishes a NO_x emission limit of 10 ng/J for residential natural gas-fired water heaters with a maximum rated capacity of 75,000 Btu/hr. Additionally, HB 965 specified that the study be completed by December 31, 2005. As part of the study, the commission surveyed residential water heater manufacturers to determine the practicality of implementing the 10 ng/J NO_x emission limit by the January 1, 2007, compliance date.

The commission was provided a list of seven manufacturers of natural gas-fired residential water heaters by the GAMA. Six of the seven manufacturers are located outside of Texas; one, PVI Industries, is located in Fort Worth. Of the seven manufacturers, three indicated that they would not formally respond to the survey because they do not manufacture residential water heaters affected by the 10 ng/J NO_x emission standard in §117.465(b)(2). The four remaining water heater manufacturers indicated that they could not manufacture a residential natural gas-fired water heater compliant with the 10 ng/J NO_x emission specification by the January 1, 2007, implementation date.

On February 28, 2006, the commission conducted a public hearing on the residential water heater study, as required by HB 965. The purpose of the hearing was to accept written and oral comments on the water heater survey results and study. Written and oral comments were submitted by the Honorable Patrick B. Haggerty, State Representative from El Paso, District 78 (Representative Haggerty); Houston Regional Group of the Sierra Club (HSC); CPS Energy; ATMOS Energy; CenterPoint Energy; Texas Gas Service; GAMA; and American Gas Association. All commenters advocated the repeal of the 10 ng/J NO_x emission specification on natural gas-fired residential water heaters.

As previously indicated in this preamble, the commission is proposing to repeal and reformat all of Chapter 117. In addition to the reformatting of existing Subchapter D, Division 1, this rulemaking would repeal the current 10 ng/J NO_x emission standard for Type 0 water heaters in existing §117.465(b)(2) due to comments received and uncertainties in the water heater manufacturers' ability to produce water heaters compliant with the current rule.

In addition, the proposed amendments to Chapter 117 would delete the definitions of "Power-vent unit" and "Direct-vent unit." With the proposed repeal of the 10 ng/J NO_x emission standard in existing §117.465(b)(2), the emission specifications for power-vent unit and direct-vent unit are duplicated in §117.465(b)(1) and §117.465(b)(3). The commission proposes to retain the emission standard found in §117.465(b)(1) that requires all equipment manufacturers to comply with the current 40 ng/J NO_x emission specification.

Demonstrating Noninterference under Federal Clean Air Act, Section 110(l)

The commission provides the following information to clarify why the repeal of the emission specification in existing §117.465(b)(2) will not negatively impact the status of the state's attainment with the ozone NAAQS. EPA issued draft guidance on June 8, 2005, "Demonstrating Noninterference Under Section 110(l) of the Clean Air Act When Revising a State Implementation Plan." The guidance states (page 6) that ". . . areas have two options available to demonstrate noninterference for the affected pollutant(s)." The commission is using option one by identifying existing measures to show compliance with EPA's guidance: substitution of one measure by another with equivalent or greater emissions reduction/air quality benefits.

Background

On April 19, 2000, the commission adopted rules in Chapter 117 to regulate emissions of NO_x from gas-fired residential water heaters statewide. These rules were part of the one-hour control strategy for the Houston-Galveston-Brazoria SIP and the Dallas-Fort Worth SIP to demonstrate attainment with the NAAQS for ozone. In November 2004, the commission adopted Early Action Compacts for the Austin and San Antonio near-nonattainment areas to assist those areas in compliance with the federal ozone standard. The commission adopted changes that delayed the January 1, 2005, emission standard compliance date to January 1, 2007, in order to provide manufacturers additional time to comply. The 79th Legislature in 2005 enacted HB 965 requiring the TCEQ to perform a study regarding the technical and economic feasibility of regulating residential water heaters.

HB 965 required the commission to conduct a survey to determine whether the residential water heater manufacturers could meet the 10 ng/J emission specification in the applicable regulations by the January 1, 2007, compliance date. Staff completed the technical and economic feasibility study in cooperation with industry and trade associations by December 31, 2005.

As part of the study, the commission was provided a list of seven manufacturers of natural gas-fired residential water heaters. Of the seven manufacturers, three indicated that they would not formally respond to the survey because they do not manufacture residential water heaters affected by the 10 ng/J NO_x emission standard in §117.465(b)(2). The four remaining water heater manufacturers indicated that they could not manufacture a residential natural gas-fired water heater compliant with the 10 ng/J NO_x emission limit by January 1, 2007.

As required by HB 965, the commission held a public hearing on the findings of the technical and economic feasibility study for residential water heaters on February 28, 2006. The requirement for reasonable notice and public hearing was satisfied through the hearing held on February 28, 2006, and the public comment period, which was held from January 30, 2006, to March 1, 2006. Commenters attending the public hearing were in favor of repealing the section of the rule that establishes a NO_x emissions specification of 10 ng/J for residential natural gas-fired water heaters.

HB 965 also required emission reductions to offset the loss of SIP credits due to the repeal of the rule. The commission intends to use reductions from a currently effective rule that were not claimed for the Houston-Galveston-Brazoria one-hour ozone attainment demonstration to offset the 0.5 tpd shortfall in the Houston-Galveston-Brazoria area. Specifically, 30 TAC Chapter 117, Subchapter D, Division 2, was adopted in April 2000 and applies to minor sources of NO_x in the Houston-Galveston-Brazoria area. While the rule is included in the Houston-Galveston-Brazoria SIP, specific reductions associated with the rule from sites that are not subject to the NO_x Mass Emission Cap and Trade (MECT) program were not claimed or modeled for the Houston-Galveston-Brazoria one-hour ozone attainment demonstration. The commission estimates that a minimum of 0.7 tpd NO_x reductions were achieved from these sources through implementation of the rule. This estimate is based only on gas-fired boilers subject to 30 TAC Chapter 117, Subchapter D, Division 2, that were not included in the MECT program. Therefore, the 0.7 tpd estimate is conservative because it does not include reductions from other sources subject to this rule that were also excluded from the MECT program.

The commission proposes to use surplus reductions from the 5% IOP SIP submittal dated April 27, 2005, to offset the 0.5 tpd shortfall in the Dallas-Fort Worth four-county ozone nonattainment area. This SIP provided information and control measures to provide for a 5% IOP from the area's 2002 emissions baseline that are in addition to federal measures and state measures already approved by EPA. As shown in Table 1 of this preamble, the 5% IOP SIP contained an overall surplus of 3.35 tpd reductions. Because the reductions exceeded the required 5%, the commission proposes to use 0.5 tpd of reductions in NO_x emissions from the nine-county lean-burn and rich-burn engine rule to offset the shortfall. According to the 5% IOP SIP, this rule will achieve a 1.87 tpd NO_x reduction by June 15, 2007, which is sufficient to offset the 0.5 tpd shortfall. The reduction requirement for the 5% IOP SIP is based on total NO_x and VOC emissions combined; therefore, adjustment to the 5% IOP SIP should not be necessary.

Figure 2: 30 TAC Chapter 117--Preamble

Conclusion

Based upon all data presently before the commission, it has been determined that there are sufficient credits in place to offset the shortfall from repealing the 10 ng/J emission specification for Type 0 water heaters. Furthermore, the replacement reductions proposed by the commission in this rulemaking are achieved from combustion sources that are ground-level NO_x emission sources and will satisfy the requirement in HB 965 to use replacement reductions from the same category. Finally, this repeal would only apply to the 10 ng/J emission specification for Type 0 water heaters. The 40 ng/J emission specification for Type 0 water heaters, as well as the emission limits for Type 1 and 2 water heaters and Type 1, 2, and 3 process heaters and small boilers, are still in effect and reductions are being achieved.

DIVISION 4: EAST TEXAS COMBUSTION

Point source NO_x emissions in Dallas-Fort Worth eight-hour ozone nonattainment area account for about one-eighth of the total inventory. The majority of NO_x in the nonattainment area comes from onroad and nonroad mobile sources. Therefore,

NO_x reductions from sources outside the Dallas-Fort Worth eight-hour ozone nonattainment area must be made so that the Dallas-Fort Worth eight-hour ozone nonattainment area can demonstrate attainment with the NAAQS for ozone. The commission's emissions inventory, as well as initial information from studies being conducted by the TCEQ and Houston Area Research Council, indicates that stationary gas-fired engines in some attainment counties of the northeast Texas area represent a significant source of NO_x emissions. The proposed rules would require owners and operators of stationary, gas-fired, reciprocating internal combustion engines, unless exempted, located in the specified counties in the northeast Texas area to meet NO_x emission specifications and other requirements in order to reduce NO_x emissions and ozone transport into the Dallas-Fort Worth eight-hour ozone nonattainment area. The specific counties included in the applicability for this proposed rulemaking include the following counties: Anderson, Bosque, Brazos, Burleson, Camp, Cass, Cherokee, Cooke, Franklin, Freestone, Grayson, Gregg, Grimes, Harrison, Henderson, Hill, Hood, Hopkins, Hunt, Lee, Leon, Limestone, Madison, Marion, Morris, Nacogdoches, Navarro, Panola, Rains, Robertson, Rusk, Shelby, Smith, Somervell, Titus, Upshur, Van Zandt, Wise, and Wood Counties. The commission is not proposing to apply this rule to engines located in the Dallas-Fort Worth eight-hour ozone nonattainment area. Engines located in the Dallas-Fort Worth eight-hour nonattainment area are either currently regulated by equivalent or more stringent requirements under other divisions of Chapter 117, or are proposed to be regulated in separate rules in this rulemaking.

The commission conducted modeling sensitivity studies at control levels similar to this proposed rule to all counties within or traversed by the 200 kilometer perimeter from the Dallas-Fort Worth eight-hour ozone nonattainment area, excluding the Dallas-Fort Worth nine-county area. Results of the sensitivity study, which estimated a NO_x reduction of 40.9 tpd, based on 2009 future case modeling, indicate the reductions realized by this rule would benefit the Dallas-Fort Worth area by reducing ozone an average of 0.2 to 0.3 parts per billion. Based on the revised list of 39 counties considered for this proposed rule, the commission estimates that implementation of this proposed rule would result in an overall reduction of approximately 37 tpd in NO_x emissions in the northeast Texas area. This rulemaking applies to engines in the point source inventory, as well as engines that are categorized in the area source inventory. Approximately 30 tpd of these reductions are from point source engines and approximately 7 tpd of these reductions are from area source engines. The commission estimates that approximately 985 stationary, gas-fired engines in the 39 counties would be subject to this rulemaking. This estimate includes stationary gas-fired engines from the point source emissions inventory, as well as stationary gas-fired engines classified as area sources. While this rulemaking is proposed as a part of the Dallas-Fort Worth Attainment Demonstration SIP, the commission anticipates that the Tyler-Longview area (Northeast Texas Early Action Compact Area) in East Texas would also benefit from NO_x reductions achieved by this rule.

SECTION BY SECTION DISCUSSION

The commission proposes to repeal Chapter 117 in its entirety. A new Chapter 117, Control of Air Pollution from Nitrogen Compounds, is proposed that incorporates existing rule language from existing Chapter 117, additional new rule language for the Dallas-Fort Worth eight-hour attainment demonstration, and rule changes that implement HB 965, concerning residential water heaters.

Reformatting Chapter 117 has resulted in numerous changes in section numbering, cross-references, as well as section, division, and subchapter titles. Section by section discussion associated with the reformatting and renumbering of Chapter 117 is primarily limited to proposing the new subchapters, divisions, and sections, and indicating the origin of the rule language from existing Chapter 117. Unless otherwise specified in this preamble, changes to section, division, and subchapter numbers and title cross-references are only to update the reference to the corresponding reformatting section numbers and new section, division, and subchapter titles. Such changes are non-substantive and will not be specifically discussed in this preamble.

Also associated with the proposed reformatting of Chapter 117 are various stylistic non-substantive changes to update rule language to current *Texas Register* style and format requirements, as well as establish more consistency in the rules. Such changes include appropriate and consistent use of acronyms, section references, equation style and formatting, scientific units of measure, and certain terminology such as "that" and "which," "shall" and "must," and "specification" and "limit." References to Houston-Galveston ozone nonattainment area have been updated to Houston-Galveston-Brazoria ozone nonattainment area to be consistent with current terminology for the region. Certain equations previously written out in paragraph and sentence form are proposed as mathematical equations for consistency and to ensure clarity and proper calculation in accordance with the commission's intent. Such changes are non-substantive and generally are not specifically discussed in this preamble.

Some changes proposed to existing rule language of Chapter 117 are necessary to make minor corrections to rule language and are discussed later in this preamble in the appropriate section discussion. As discussed previously in this preamble, comments received regarding sections and rule language associated only with reformatting and minor stylistic changes will not be considered and no changes will be made based on such comments. Section by section discussion is presented in the order of the proposed new section numbering order.

SUBCHAPTER A, DEFINITIONS

The commission proposes a new Chapter 117, Subchapter A, entitled Definitions, that incorporates the definitions in the existing Chapter 117, Subchapter A, relating to definitions.

Section 117.10, Definitions

The commission proposes a new §117.10 that incorporates the definitions in the existing §117.10, relating to definitions, with the following revisions. Proposed new §117.10(1) - (53) incorporate the definitions from existing §117.10(1) - (53), respectively. Specific changes to definitions are discussed as follows.

The commission proposes revising §117.10(2), concerning applicable ozone nonattainment area. The commission proposes to move the existing §117.10(2)(C), Houston/Galveston, to the new §117.10(2)(D) and revises the proposed new §117.10(2)(D) to be Houston-Galveston-Brazoria ozone nonattainment area to be consistent with current terminology and other proposed changes in this rulemaking. The commission proposes adding the definition of Dallas-Fort Worth eight-hour ozone nonattainment area to the definition of applicable ozone nonattainment area in §117.10(2)(C). The proposed new definition for the Dallas-Fort Worth eight-hour ozone nonattainment area includes Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties. This change, and subsequent changes to other definitions in this section to include Dallas-Fort

Worth eight-hour ozone nonattainment area are necessary because the commission is proposing new rules for the Dallas-Fort Worth eight-hour ozone nonattainment area. The existing definition of Dallas-Fort Worth ozone nonattainment area would continue to apply only to Collin, Dallas, Denton, and Tarrant Counties.

The commission proposes revising §117.10(14)(A), electric power generating system, to include systems that are owned or operated by an electric cooperative, independent power producer, municipality, river authority, public utility, or a PUC-regulated utility. This change is proposed to more accurately reflect the definition of an electric power generating system and does not expand the definition. In addition, the commission proposes adding "Dallas-Fort Worth eight-hour" to the list of ozone nonattainment areas included in the definition of electric power generating system in proposed new §117.10(14)(A)(iii). Existing §117.10(14)(A)(iii), which includes "Houston-Galveston-Brazoria" in the list of ozone nonattainment areas is proposed to be incorporated into proposed new §117.10(14)(A)(iv).

The commission proposes revising the definition of emergency situation in §117.10(15)(A)(ii) to update the references to the Electric Reliability Council of Texas (ERCOT) Protocols, to the most recent published version of the ERCOT Protocols, April 25, 2006.

The commission proposes to change large DFW system in §117.10(24) to large utility system to be consistent with *Texas Register* style and formatting requirements. In addition, the commission proposes to revise the definition in §117.10(24) to include systems located in the Dallas-Fort Worth eight-hour ozone nonattainment area.

The commission proposes revising the definition of major source in §117.10(29)(B) to include sources located in the Dallas-Fort Worth eight-hour ozone nonattainment area. In addition, Ellis and Parker Counties are proposed to be removed from §117.10(29)(D) because these counties are classified as nonattainment and are included in the proposed revised §117.10(29)(B).

The commission proposes revising the definition of parts per million by volume in §117.10(35) to include the equation that must be used to adjust pollutant concentrations to a specified oxygen (O_2) correction basis. This change is necessary to ensure that all measured concentrations are corrected to the specified O_2 correction basis, when required by an applicable rule, using a consistent methodology.

The commission proposes changing plant-wide emission limit in §117.10(37) to plant-wide emission specification to be consistent with proposed new section titles.

The commission proposes changing small DFW system in §117.10(44) to small utility system to be consistent with *Texas Register* style and formatting requirements. In addition, the commission proposes to revise the definition in §117.10(44) to include the Dallas-Fort Worth eight-hour ozone nonattainment area.

The commission proposes changing system-wide emission limit in §117.10(48) to system-wide emission specification to be consistent with proposed new section titles.

The commission proposes several revisions to the definition of unit in existing §117.10(51). Proposed new §117.10(51)(C) is revised to include a reference to proposed new §117.2110, Emission Specifications for Eight-Hour Attainment Demonstration, to define unit when used in the proposed new Subchapter D, Division 2, Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources. In addition, the commission proposes adding a new §117.10(51)(D) to existing §117.10(51) to define unit for the purposes of proposed new Subchapter E, Division 4, East Texas Combustion. The proposed new §117.10(51)(D) states that for the purposes of §117.3310, relating to emission specification for eight-hour attainment demonstration, and each requirement of this chapter associated with §117.3310, a unit consists of any stationary internal combustion engine, as defined in §117.10, relating to definitions.

The commission proposes adding a new §117.10(51)(E) to the existing §117.10(51) to define unit for the purposes of proposed new Subchapter B, Division 4, Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources, and Subchapter C, Division 4, Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources. The proposed new §117.10(51)(E) specifies that for the purposes of proposed new §117.410 and §117.1310, relating to emission specification for eight-hour attainment demonstration, and each requirement of this chapter associated with §117.410 and §117.1310, a unit consists of any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in §117.10, relating to definitions, or any other stationary source of NO_x emissions at a major source, as defined in §117.10.

Finally, the commission proposes to revise the definition of utility boiler in existing §117.10(52). Proposed new §117.10(52) revises the definition to include equipment owned or operated by an electric cooperative, independent power producer, municipality, river authority, public utility, or PUC-regulated utility. This proposed change is intended to clarify the definition and to be consistent with other proposed changes in this rulemaking, but does not expand the applicability of the definition.

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

The commission proposes a new Chapter 117, Subchapter B, entitled Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Nonattainment Areas, that incorporates the rule language in the existing Chapter 117, Subchapter B, Combustion at Major Sources, Division 3, Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas. The structure of proposed new Subchapter B is based on regional ozone nonattainment areas. Each proposed new division applies only to a specific ozone nonattainment area. Rule language from existing Subchapter B, Division 3 that is not applicable for the specific region is not proposed to be included in the new division for that specific region. Unless otherwise specified in this preamble, such exclusions of rule language not applicable to the specific region are considered non-substantive changes and are not specifically discussed in the preamble.

In addition, the commission proposes a new Subchapter B, Division 4, entitled Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources, that includes new rule language and requirements associated with major industrial, commercial, and institutional sources in the Dallas-Fort Worth eight-hour ozone nonattainment area. The new Subchapter B, Division 4 is proposed as a part of the commission's eight-hour ozone attainment demonstration for the Dallas-Fort Worth eight-hour ozone nonattainment area.

DIVISION 1, BEAUMONT-PORT ARTHUR OZONE NONATTAINMENT AREA MAJOR SOURCES

The commission proposes a new Chapter 117, Subchapter B, Division 1, entitled Beaumont-Port Arthur Ozone Nonattainment Area Major Sources, that incorporates the rule language in the existing Chapter 117, Subchapter B, Division 3 applicable to major industrial, commercial, and institutional sources in the Beaumont-Port Arthur ozone nonattainment area.

Section 117.100, Applicability

The commission proposes a new §117.100 that incorporates the rule language in the existing §117.201, that are applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.100(1) - (3) incorporates the applicability rule language in existing §117.201(1) - (3).

Section 117.103, Exemptions

The commission proposes a new §117.103 that incorporates the exemption rule language in the existing §117.203 that are applicable to the Beaumont-Port Arthur ozone nonattainment area. The commission proposes a new §117.103(a)(1) - (7), relating to general exemptions, that incorporates the exemptions in the existing §117.203(a)(1) - (7). Proposed new §117.103(a)(8) incorporates the exemption of existing §117.203(a)(8)(B) and proposed new §117.103(a)(9) and (10) incorporate the exemptions in existing §117.203(a)(10) and (13).

In addition, the commission proposes a new §117.103(b) and (c) to incorporate exemptions from existing §117.205 and §117.206. This proposed change would consolidate the applicable exemptions for the Beaumont-Port Arthur ozone nonattainment area under a single section. The commission proposes a new §117.103(b)(1) - (5) consisting of the provisions in the existing §117.205(h)(1) - (5), concerning exemptions for RACT, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.103(b)(6) - (8) incorporates the exemptions in existing §117.205(h)(7) - (9), and proposed new §117.103(b)(10) incorporates the exemption in existing §117.205(h)(10)(B). The commission proposes a new §117.103(c), relating to attainment demonstration exemptions, that incorporates the exemption in existing §117.206(g) and (g)(2). The exemption in existing §117.206(g)(1), for boilers or process heaters with a maximum rated capacity less than 40 million British thermal units per hour (MMBtu/hr), is redundant because the general exemption in proposed new §117.103(a)(2) is identical.

Section 117.105, Emission Specifications for Reasonably Available Control Technology (RACT)

The commission proposes a new §117.105 that incorporates rule language in existing §117.205, relating to emission specifications for RACT, applicable to the Beaumont-Port Arthur ozone nonattainment area.

The commission proposes a new §117.105(a) - (c) consisting of the provisions in the existing §117.205(a) - (c). In addition, the commission proposes a new equation in §117.105(b)(6) that incorporates the calculation for the NO_x emission limit for gas-fired boilers and process heaters using hydrogen-rich fuel in the existing §117.205(b)(6). The proposed new equation in §117.105(b)(6) is identical in content to the existing equation in §117.205(b)(6). The proposed new equation in §117.105(b)(6) presents the equation in a format consistent with other figures and equations in Chapter 117 and provides a written description of all the terms used in the equation.

The commission proposes a new §117.105(d) consisting of the provisions in existing §117.205(d) and (d)(2). Proposed new §117.105(e) - (g) consisting of the provisions in the existing §117.205(e) - (g). Exemptions applicable in the Beaumont-Port-Arthur ozone nonattainment area in existing §117.205(h) are proposed to be incorporated in proposed new §117.103. The commission proposes a new §117.105(h) consisting of the provisions in the existing §117.205(i) and (i)(1).

Section 117.110, Emission Specifications for Attainment Demonstration

The commission proposes a new §117.110 that incorporates the rule language in existing §117.206, relating to emission specifications for attainment demonstrations, applicable to the Beaumont-Port Arthur ozone nonattainment area.

The commission proposes a new §117.110(a) that incorporates the NO_x emission specifications for the Beaumont-Port Arthur ozone nonattainment area in existing §117.206(a). The commission proposes a new §117.110(b), relating to NO_x averaging time, that incorporates the rule language in the existing §117.206(d)(1). Proposed new §117.110(b)(1) incorporates the requirements in existing §117.206(d)(1)(A), and proposed new §117.110(b)(2) incorporates the requirements in existing §117.206(d)(1)(B).

The commission proposes a new §117.110(c), relating to related emissions, that incorporates the rule language in existing §117.206(e). Proposed new §117.110(c)(1) and (2) incorporate the carbon monoxide (CO) and ammonia emissions specifications in the existing §117.206(e)(1) and (2). Proposed new §117.110(c)(3) incorporates the provisions regarding correction of CO emissions in existing §117.206(e)(3) and (3)(B). The commission also proposes a new §117.110(c)(4) that incorporates the rule language regarding applicability of the CO emission specifications from existing §117.206(e)(4) and (4)(A). Finally, the commission proposes a new §117.110(d) that incorporates the rule language regarding compliance flexibility from the existing §117.206(f)(1) - (3).

Section 117.115, Alternative Plant-Wide Emission Specifications

The commission proposes a new §117.115 that incorporates the rule language in existing §117.207, relating to alternative plant-wide emission specifications, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.115(a) - (f) incorporates the rule language in the existing §117.207(a) - (f), relating to alternative plant-wide emission specifications, applicable to the Beaumont-Port Arthur ozone nonattainment area.

Proposed new §117.115(g) incorporates the rule language from existing §117.207(g). In addition, existing §117.207(g)(1) - (3) include required calculations written in paragraph form rather than in equation form. The commission is proposing to reformat the calculations in a mathematical formula rather than the paragraph form to present the equations in a format consistent with other equations in Chapter 117 and provide a written description of all the terms used in the equation. The proposed new formulas are identical in content to the existing required calculations in paragraph form. The proposed new equation in §117.115(g)(1) incorporates the calculation for the allowable NO_x emission rate for each affected boiler and process heater in the existing §117.207(g)(1). The proposed new equation in §117.115(g)(2) incorporates the calculation for the allowable NO_x emission rate for each affected stationary internal combustion engine in the existing §117.207(g)(2). The commission also proposes adding new equations to §117.115(g)(3) that incorporate the calculation for the allowable NO_x emission rate for each affected stationary gas turbine in the existing §117.207(g)(3). The proposed new §117.115(g)(3) presents the equation for determining the plant-wide emission specification for stationary gas turbines from the required calculation in existing §117.207(g)(3). Proposed new §117.115(g)(3) also includes a new equation in §117.115(g)(3) that incorporates the existing equation for calculating the in-stack NO_x concentration term used in calculating the plant-wide emission specification.

Finally, the commission proposes a new §117.115(h) that incorporates the rule language from existing §117.207(h), and a new §117.115(i) that incorporates the rule language from existing §117.207(i) and (i)(1).

Section 117.123, Source Cap

The commission proposes a new §117.123 that incorporates the rule language in existing §117.223, relating to source cap, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.123(a) - (k) incorporate the rule language in existing §117.223(a) - (k). In addition, the commission proposes new equations in §117.123(b) that incorporate the equations in existing §117.223(b) to present the equations in a format consistent with other equations in Chapter 117 and provide a written description of all the terms used in the equation. The proposed new equations in §117.123(b) include only the information applicable to the Beaumont-Port Arthur ozone nonattainment area. The proposed new equation in §117.123(b)(1) incorporates the equation for the rolling 30-day average emission cap in existing §117.223(b)(1). The commission proposes a new equation in §117.123(b)(2) that incorporates the equation for the maximum daily emission cap in existing §117.223(b)(2).

For proposed new §117.123(k), the commission proposes to replace upset period with the language "emissions event, as defined in §101.1 of this title (relating to Definitions)." This proposed change is necessary to update the rule to current terminology used by the commission.

Section 117.125, Alternative Case Specific Specifications

The commission proposes a new §117.125 that incorporates the rule language in the existing §117.221, relating to alternative case specific specifications, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.125(a) and (b) incorporate the rule language in existing §117.221(a) and (b). In addition, proposed new §117.125(a) omits the existing §117.221(a)(4) because the Engineering Services Team no longer exists within the TCEQ.

Section 117.130, Operating Requirements

The commission proposes a new §117.130 that incorporates the rule language in existing §117.208, relating to operating requirements, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.130(a) - (d) incorporate the rule language in existing §117.208(a) - (d). In addition, the commission is concurrently proposing a new §117.8140(b) that incorporates the engine testing requirements in the existing §117.208(d)(7). Therefore, the engine testing requirements in existing §117.208(d)(7) have been omitted from the proposed new §117.130(d)(7) and replaced with a reference to the proposed new §117.8140(b).

Section 117.135, Initial Demonstration of Compliance

The commission proposes a new §117.135 that incorporates the rule language in existing §117.211, relating to initial demonstration of compliance, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.135(a) - (d) incorporate the rule language in existing §117.211(a) - (d). The commission is concurrently proposing a new §117.8000 that incorporates the requirements in the existing §117.211(e). Therefore, the commission proposes a new §117.135(e) that replaces specific requirements from existing §117.211(e) with a reference to the proposed new §117.8000.

In addition, while existing §117.211(a) and proposed new §117.135(a) specify that units that inject urea or ammonia for NO_x control must be tested for ammonia emissions, existing §117.211(e) does not specify the methods to be used for the required ammonia initial demonstration of compliance. Proposed new §117.8000 includes a requirement that specifies the methods required for ammonia testing during the initial demonstration of compliance. Specific discussion related to this proposed change is included in the section-by-section discussion associated with proposed new §117.8000.

Proposed new §117.135(f) incorporates the rule language from existing §117.211(f), regarding initial demonstration of compliance for units operating with continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS). Finally, the commission is concurrently proposing a new §117.8010 that incorporates the report content requirements in the existing §117.211(g). Therefore, the proposed new §117.135(g) omits the compliance stack reports content requirements and references proposed new §117.8010.

Section 117.140, Continuous Demonstration of Compliance

The commission proposes a new §117.140 that incorporates the rule language in the existing §117.213, relating to continuous demonstration of compliance, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.140(a) incorporates the totalizing fuel flow meter requirements and alternative provisions from existing §117.211(a), (a)(1)(A), and (a)(2). Proposed new §117.140(b) incorporates the rule language from existing §117.213(b) concerning O_2 monitors. In addition, existing §117.213(b)(1)(B)(i) requires O_2 monitors on process heaters greater than or equal to 100 MMBtu/hr, and clause (ii) requires O_2 monitors on process heaters greater than or equal to 200 MMBtu/hr except as provided in §117.213(f). Because existing §117.213(b)(1)(B)(i) and (ii) are overlapping requirements, the proposed new §117.140(b)(1)(B) incorporates both existing §117.213(b)(1)(B)(i) and (ii) into a single requirement for O_2 monitors on process heaters greater than or equal to 100 MMBtu/hr, except as provided in subsection (f).

The commission proposes a new §117.140(c) incorporating the rule language from existing §117.213(c), regarding requirements for NO_x monitors, applicable to the Beaumont-Port Arthur ozone nonattainment area. In addition, the reference in existing §117.213(c)(3)(C)(ii) to §117.113(f) is revised in proposed new §117.140(c)(3)(C)(ii) to reference proposed new §117.8110(b) because the applicable provisions in §117.113(f) are proposed to be incorporated in new §117.8110.

The commission proposes a new §117.140(d), concerning CO monitoring requirements. The commission is concurrently proposing a new §117.8120 that incorporates the CO monitoring methods in the existing §117.213(d)(1) - (4). Therefore, the proposed new §117.140(d) omits the existing CO monitoring methods specified in §117.213(d)(1) - (4) and references proposed new §117.8120.

The commission proposes a new §117.140(e), concerning requirements for CEMS. The commission is concurrently proposing a new §117.8100(a) that incorporates the general requirements for CEMS in the existing §117.213(e)(1) - (3), (5), and (6). Existing §117.213(e)(4) is a region-specific requirement applicable only in the Houston-Galveston-Brazoria ozone nonattainment area. Therefore, the proposed new §117.140(e) omits existing §117.213(e)(1) - (6) and references proposed new §117.8100(a).

The commission proposes a new §117.140(f), concerning requirements for PEMS. Proposed new §117.140(f)(1) incorporates rule language from existing §117.213(f)(1). The commission is concurrently proposing a new §117.8100(b) that incorporates the general requirements for PEMS in the existing §117.213(f)(2) - (7). Therefore, the proposed new §117.140(f) omits existing §117.213(f)(2) - (7) and proposed new §117.140(f)(2) references proposed new §117.8100(b).

The commission proposes a new §117.140(g) concerning testing requirements for stationary gas engines. The commission is concurrently proposing a new §117.8140(a) that incorporates the engine testing requirements in existing §117.213(g)(1). Therefore, the proposed new §117.140(g) omits existing §117.213(g)(1) and references proposed new §117.8140(a). In addition, existing §117.213(g)(2) requires that engines that use a chemical reagent for reduction of NO_x must be monitored for NO_x in accordance with existing §117.213(c)(1)(E) and must comply with applicable requirements for CEMS and PEMS. Existing §117.213(c)(1)(E) and proposed new §117.140(c)(1)(E) require that the owner or operator of any unit that uses a chemical reagent for NO_x control install, calibrate, maintain, and operate a CEMS or PEMS to monitor NO_x. Also, the applicable requirements for CEMS or PEMS in existing §117.213(e) or (f), or proposed new §117.140(e) or (f) automatically apply to any CEMS or PEMS required by the section. Therefore, because the existing §117.213(g)(2) is redundant, the commission is not proposing to incorporate §117.213(g)(2) into the proposed new §117.140(g).

Finally, the commission proposes new §117.140(h) - (m) that incorporates the rule language from existing §117.213(h) - (m) applicable to the Beaumont-Port Arthur ozone nonattainment area.

Section 117.145, Notification, Recordkeeping, and Reporting Requirements

The commission proposes new §117.145 that incorporates the rule language in existing §117.219, concerning notification, recordkeeping, and reporting. Proposed new §117.145(a) - (f) incorporate the rule language from existing §117.219(a) - (f) requirements applicable to the Beaumont-Port Arthur ozone nonattainment area. In addition, for proposed new §117.145(a), the commission proposes to replace the language "the startup and/or shutdown exemptions allowed under §101.222" with "the startup and/or shutdown provisions of §101.222 . . .." The reference to exemptions is not applicable to §101.222 and the proposed change is necessary to clarify proposed new §117.145(a). The commission is soliciting comments on this specific change to the language in existing §117.219(a). The commission is also soliciting comments on whether the reference to 30 TAC §101.222 should be removed.

Section 117.150, Initial Control Plan Procedures

The commission proposes new §117.150 that incorporates the rule language in existing §117.209, concerning initial control plan procedures applicable to the Beaumont-Port Arthur ozone nonattainment area.

Section 117.152, Final Control Plan Procedures for Reasonably Available Control Technology

The commission proposes a new §117.152 that incorporates the requirements in the existing §117.215, relating to final control plan procedures for RACT, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.152(a) - (c) incorporates the provisions in the existing §117.215(a) - (c). Proposed new §117.152(a)(2)(A) and (B) incorporate the rule language from existing §117.215(a)(2)(A) and (B). Proposed new §117.152(a)(2)(C) incorporates the rule language from existing §117.215(a)(2)(D), and proposed new §117.152(a)(2)(D) incorporates the rule language from existing §117.215(a)(2)(C). Proposed new §117.152(a)(2)(E) incorporates the rule language from existing §117.215(a)(2)(E). In addition, for proposed new §117.152(a)(6)(B), concerning the information required in the final control plan for gas turbines with a megawatt (MW) rating less than 10 MW, the commission is proposing to change the word "ten" to the numeral "10.0" because this is the appropriate exemption MW rating from existing §117.205(h)(7) and proposed new §117.103(b)(6).

Proposed new §117.152 does not include existing §117.215(d), concerning the requirement to submit the control plan electronically and on hard copy using forms provided by the executive director. Existing §117.215 and proposed new §117.152 specify the content requirements for the control plans. Therefore, a mandatory format for the control plan information is not necessary. Finally, proposed new §117.152(d) incorporates rule language in existing §117.215(e).

Section 117.154, Final Control Plan Procedures for Attainment Demonstration Emission Specifications

The commission proposes a new §117.154 that incorporates the rule language in existing §117.216, relating to final control plan procedures for attainment demonstration emission specifications, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.154(a) incorporates the rule language in existing §117.216(a). Proposed new §117.154(a)(1)(A) consists of the provisions in existing §117.216(a)(1)(A). Proposed new §117.154(a)(1)(B) consists of the provisions in existing §117.216(a)(1)(D). Proposed new §117.154(a)(1)(C) and (D) consist of the provisions in existing §117.216(a)(1)(B) and (C), respectively. The commission proposes a new §117.154(a)(2) - (5) that incorporates the rule language from existing §117.216(a)(2) - (5). The commission also proposes a new §117.154(b) and (c) that incorporate the rule language in existing §117.216(b) and (c), respectively. In addition, proposed new §117.154(b)(2)(A) and (B) exclude the references to proposed new §117.123(k) or (l) because there is no heat input information specified in these subsections in either the existing §117.223 or proposed new §117.123.

Section 117.156, Revision of Final Control Plan

The commission proposes a new §117.156 that incorporates the rule language in existing §117.217, concerning revisions of final control plans.

DIVISION 2, DALLAS-FORT WORTH OZONE NONATTAINMENT AREA MAJOR SOURCES

The commission proposes a new Chapter 117, Subchapter B, Division 2, entitled Dallas-Fort Worth Ozone Nonattainment Area Major Sources, that incorporates the rule language in the existing Chapter 117, Subchapter B, Division 3 applicable to major industrial, commercial, and institutional sources in the Dallas-Fort Worth ozone nonattainment area.

Section 117.200, Applicability

The commission proposes a new §117.200 that incorporates the applicability rule language in existing §117.201 applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.200(a) incorporates the applicability rule language in existing §117.201(1) - (3). In addition, the commission proposes a new §117.200(b) specifying that proposed new Chapter 117, Subchapter B, Division 2 will no longer apply to any units that are subject to the emission specifications in proposed new §117.410 and located at any major stationary source of NO_x within Collin, Dallas, Denton, and Tarrant Counties after the compliance dates in proposed new §117.9030. The emissions specifications in proposed §117.410 and all other associated requirements in the proposed new Subchapter B, Division 4, Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources, would supersede the requirements of Subchapter B, Division 2. Therefore, the commission proposes new §117.200(b) to avoid overlapping requirements from the two separate divisions.

Section 117.203, Exemptions

The commission proposes a new §117.203, relating to general exemptions, that incorporates the exemptions in the existing §117.203 applicable to the Dallas-Fort Worth ozone nonattainment area. The commission proposes a new §117.203(a), relating to general exemptions, that incorporates the exemptions in the existing §117.203(a). Proposed new §117.203(a)(1) - (7) incorporates the rule language in existing §117.203(a)(1) - (7). Proposed new §117.203(a)(8) incorporates the exemption of existing §117.203(a)(8)(B). Proposed new §117.203(a)(9) incorporates the exemption in existing §117.203(a)(10).

In addition, the commission proposes a new §117.203(b) and (c) to incorporate exemptions from existing §117.205 and §117.206. This proposed change would consolidate the applicable exemptions for the Dallas-Fort Worth ozone nonattainment area under a single section. Proposed new §117.203(b)(1) - (9) incorporates the exemptions in the existing §117.205(h)(1) - (9), concerning exemptions for RACT, applicable to the Dallas-Fort Worth ozone nonattainment area. The commission proposes a new §117.203(b)(10) consisting of the provisions in the existing §117.205(h)(10)(B).

The commission proposes a new §117.203(c), relating to attainment demonstration exemptions, that incorporates the exemptions in existing §117.206(g)(2) applicable to the Dallas-Fort Worth ozone nonattainment area. The exemption in existing §117.206(g)(1), for boilers or process heaters with a maximum rated capacity less than 40 MMBtu/hr, is redundant because the general exemption in proposed new §117.203(a)(2) is identical.

Section 117.205, Emission Specifications for Reasonably Available Control Technology (RACT)

The commission proposes a new §117.205 that incorporates rule language in existing §117.205, relating to emission specifications for RACT, applicable to the Dallas-Fort Worth ozone nonattainment area.

The commission proposes a new §117.205(a) - (c) consisting of the provisions in the existing §117.205(a) - (c). In addition, the language regarding initial control plans in existing §117.205(a)(1)(B) is omitted in the proposed new §117.205(a)(1)(B) because the requirement for initial control plans was not applicable in the Dallas-Fort Worth ozone nonattainment area. Also, the commission proposes a new equation in §117.205(b)(6) that incorporates the calculation for the NO_x emission limit for gas-fired boilers and process heaters using hydrogen-rich fuel in the existing §117.205(b)(6). The proposed new equation in §117.205(b)(6) is identical in content to the existing equation in existing §117.205(b)(6). The proposed new §117.205(b)(6) presents the equation in a format consistent with other figures in Chapter 117 and provides a written description of all the terms used in the equation.

The commission proposes a new §117.205(d) consisting of the rule language in the existing §117.205(d) and (d)(2). Proposed new §117.205(e) and (f) incorporate the rule language in existing §117.205(f) and (g). As previously indicated in this preamble, the exemptions in existing §117.205(h) applicable to the Dallas-Fort Worth ozone nonattainment area are proposed to be incorporated in proposed new §117.203(b).

Section 117.210, Emission Specifications for Attainment Demonstration

The commission proposes a new §117.210 that incorporates the rule language in the existing §117.206, relating to emission specifications for attainment demonstration, applicable to the Dallas-Fort Worth ozone nonattainment area.

The commission proposes a new §117.210(a), relating to NO_x emission specifications, that incorporates the specifications in existing §117.206(b). Proposed new §117.210(a)(1) and (2) incorporate the emission specifications from existing §117.206(b)(1) and (2). The emission specifications for stationary gas-fired internal combustion engines in existing §117.206(b)(3) are proposed to be incorporated in proposed new Subchapter B, Division 4, §117.410(a). These emission specifications are applicable to the nine-county Dallas-Fort Worth eight-hour ozone nonattainment area as a part of the commission's IOP demonstration for the Dallas-Fort Worth eight-hour ozone nonattainment area. Because the emission specifications in existing §117.206(b)(3) apply to the Dallas-Fort Worth eight-hour ozone nonattainment area, proposed new Subchapter B, Division 4 is the most appropriate location for the emission specifications.

The commission proposes a new §117.210(b), relating to NO_x averaging time, that incorporates the rule language in existing §117.206(d)(1). Proposed new §117.210(b)(1) incorporates the requirements in existing §117.206(d)(1)(A), and proposed new §117.210(b)(2) incorporates the requirements in existing §117.206(d)(1)(B).

The commission proposes a new §117.210(c), relating to related emissions, that incorporates the rule language in existing §117.206(e). Proposed new §117.210(c)(1) and (2) incorporate the CO and ammonia emissions specifications in the existing §117.206(e)(1) and (2). Proposed new §117.210(c)(3) incorporates the provisions regarding correction of CO emissions in existing §117.206(e)(3) and (3)(B). The commission also proposes a new §117.210(c)(4) that incorporates the rule language regarding applicability of the CO emission specifications from existing §117.206(e)(4) and (4)(A). Finally, the commission proposes a new §117.210(d) that incorporates the rule language regarding compliance flexibility from the existing §117.206(f)(1) - (3). As previously indicated in this preamble, the exemptions in existing §117.206(g) applicable to the Dallas-Fort Worth ozone nonattainment area are proposed to be incorporated in proposed new §117.203(c).

Section 117.215, Alternative Plant-Wide Emission Specifications

The commission proposes a new §117.215 that incorporates the rule language in existing §117.207, relating to alternative plant-wide emission specifications, applicable to the Dallas-Fort Worth zone nonattainment area. Proposed new §117.215(a) - (f) incorporate the rule language in existing §117.207(a) - (f).

Proposed new §117.215(g) incorporates the rule language from existing §117.207(g). In addition, existing §117.207(g)(1) - (3) include required calculations written in paragraph form rather than in equation form. The commission is proposing to reformat the calculations in a mathematical formula rather than the paragraph form to present the equations in a format consistent with other equations in Chapter 117 and provide a written description of all the terms used in the equation. The proposed new formulas are identical in content to the existing required calculations in paragraph form. The proposed new equation in §117.215(g)(1) incorporates the calculation for the allowable NO_x emission rate for each affected boiler and process heater in the existing §117.207(g)(1). The proposed new equation in §117.215(g)(2) incorporates the calculation for the allowable NO_x emission rate for each affected stationary internal combustion engine in the existing §117.207(g)(2). The commission also proposes adding new equations to §117.215(g)(3) that incorporate the calculation for the allowable NO_x emission rate for each affected stationary gas turbine in the existing §117.207(g)(3). The proposed new §117.215(g)(3) presents the equation for determining the plant-wide emission specification for stationary gas turbines from the required calculation in existing §117.207(g)(3). Proposed new §117.215(g)(3) also includes a new equation in §117.215(g)(3) that incorporates the existing equation for calculating the in-stack NO_x concentration term used in calculating the plant-wide emission specification.

Finally, the commission proposes a new §117.215(h) that incorporates the rule language from existing §117.207(h), and a new §117.215(i) that incorporates the rule language from existing §117.207(i) and (i)(2).

Section 117.223, Source Cap

The commission proposes a new §117.223 that incorporates the rule language in the existing §117.223, relating to source cap, applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.223(a) - (k) incorporate the rule language in existing §117.223(a) - (k). In addition, the commission proposes new equations in proposed new §117.223(b) that incorporate the equations in existing §117.223(b) to present the equations in a format consistent with other equations in Chapter 117 and provide a written description of all the terms used in the equation. The proposed new equations in §117.223 include only the information applicable to the Dallas-Fort Worth ozone nonattainment area. The proposed new equation in §117.223(b)(1) incorporates the equation for the rolling 30-day average emission cap in the existing §117.223(b)(1). The proposed new equation in §117.223(b)(2) incorporates the equation for the rolling 30-day average NO_x emission cap in the existing §117.223(b)(2).

In addition, the commission proposes to revise the language regarding initial control plans in proposed new §117.223(i) and (j). As discussed later in this preamble, the commission is not proposing a new section for the Dallas-Fort Worth ozone nonattainment area with the requirements for initial control plans from existing §117.209. Therefore, the commission proposes to change the language in the proposed new §117.223(i) and (j) to reference final control plans for RACT instead of initial control plans. The commission is soliciting comment on this specific change proposed for §117.223(i) and (j). Finally, for proposed new §117.223(k), the commission proposes to replace upset period with the language "emissions event, as defined in §101.1 of this title (relating to Definitions)." This proposed change is necessary to update the rule to current terminology used by the commission.

Section 117.225, Alternative Case Specific Specifications

The commission proposes a new §117.225 that incorporates the rule language in the existing §117.221, relating to alternative case specific specifications, applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.225(a) and (b) incorporate the rule language in the existing §117.221(a) and (b). In addition, proposed new §117.225(a) omits the existing §117.221(a)(4) because the Engineering Services Team no longer exists within the TCEQ.

Section 117.230, Operating Requirements

The commission proposes a new §117.230 that incorporates the rule language in existing §117.208, relating to operating requirements, applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.230(a) - (d) incorporate the rule language in existing §117.208(a) - (d). In addition, the commission is concurrently proposing a new §117.8140(b) that incorporates the engine testing requirements in the existing §117.208(d)(7). Therefore, the engine testing requirements in existing §117.208(d)(7) have been omitted from the proposed new §117.230(d)(7) and replaced with a reference to the proposed new §117.8140(b).

Section 117.235, Initial Demonstration of Compliance

The commission proposes a new §117.235 that incorporates the rule language in existing §117.211, relating to initial demonstration of compliance, applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.235(a) - (d) incorporate the rule language in existing §117.211(a) - (d). The commission is concurrently proposing a new §117.8000 that incorporates the requirements in the existing §117.211(e). Therefore, the commission proposes a new §117.235(e) that replaces specific requirements from existing §117.211(e) with a reference to the proposed new §117.8000. In addition, while existing §117.211(a) and proposed new §117.235(a) specify that units that inject urea or ammonia for NO_x control must be tested for ammonia emissions, existing §117.211(e) does not specify the methods to be used for the required ammonia initial demonstration of compliance. Proposed new §117.8000 includes a requirement that specifies the methods required for ammonia testing during the initial demonstration of compliance. Specific discussion related to this proposed change is included in the section by section discussion associated with proposed new §117.8000.

Proposed new §117.235(f) incorporates the rule language from existing §117.211(f), regarding initial demonstration of compliance for units operating with CEMS or PEMS. Finally, the commission is concurrently proposing a new §117.8010 that incorporates the report content requirements in the existing §117.211(g). Therefore, the proposed new §117.235(g) omits the compliance stack reports content requirements and references proposed new §117.8010.

Section 117.240, Continuous Demonstration of Compliance

The commission proposes a new §117.240 that incorporates the rule language in the existing §117.213, relating to continuous demonstration of compliance, applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.240(a) incorporates the totalizing fuel flow meter requirements and alternative provisions from existing §117.211(a), (a)(1)(A), and (a)(2). Proposed new §117.240(b) incorporates the rule language from existing §117.213(b) concerning O_2 monitors. In addition, existing §117.213(b)(1)(B)(i) requires O_2 monitors on process heaters greater than or equal to 100 MMBtu/hr, and clause (ii) requires O_2 monitors on process heaters greater than or equal to 200 MMBtu/hr except as provided in §117.213(f). Because existing §117.213(b)(1)(B)(i) and (ii) are overlapping requirements, the proposed new §117.240(b)(1)(B) incorporates both existing §117.213(b)(1)(B)(i) and (ii) into a single requirement for O_2 monitors on process heaters greater than or equal to 100 MMBtu/hr, except as provided in subsection (f).

The commission proposes a new §117.240(c) incorporating the rule language from existing §117.213(c), regarding requirements for NO_x monitors, applicable to the Dallas-Fort Worth ozone nonattainment area. In addition, the reference in existing §117.213(c)(3)(C)(ii) to §117.113(f) is revised in proposed new §117.240(c)(3)(C)(ii) to reference proposed new §117.8110(b) because the applicable provision in §117.113(f) if proposed to be incorporated in new §117.8110.

The commission proposes a new §117.240(d), concerning CO monitoring requirements. The commission is concurrently proposing a new §117.8120 that incorporates the CO monitoring methods in the existing §117.213(d)(1) - (4). Therefore, the proposed new §117.240(d) omits the existing CO monitoring methods specified in §117.213(d)(1) - (4) and references proposed new §117.8120.

The commission proposes a new §117.240(e), concerning requirements for CEMS. The commission is concurrently proposing a new §117.8100(a) that incorporates the general requirements for CEMS in the existing §117.213(e)(1) - (3), (5), and (6). Existing §117.213(e)(4) is a region-specific requirement applicable only in the Houston-Galveston-Brazoria ozone nonattainment area. Therefore, the proposed new §117.240(e) omits existing §117.213(e)(1) - (6) and references proposed new §117.8100(a).

The commission proposes a new §117.240(f), concerning requirements for PEMS. Proposed new §117.240(f)(1) incorporates rule language from existing §117.213(f)(1). The commission is concurrently proposing a new §117.8100(b) that incorporates the general requirements for PEMS in the existing §117.213(f)(2) - (7). Therefore, the proposed new §117.240(f) omits existing §117.213(f)(2) - (7) and proposed new §117.240(f)(2) references proposed new §117.8100(b).

The commission proposes a new §117.240(g) concerning testing requirements for stationary gas engines. The commission is concurrently proposing a new §117.8140(a) that incorporates the engine testing requirements in existing §117.213(g)(1). Therefore, the proposed new §117.240(g) omits existing §117.213(g)(1) and references proposed new §117.8140(a). In addition, existing §117.213(g)(2) requires that engines that use a chemical reagent for reduction of NO_x must be monitored for NO_x in accordance with existing §117.213(c)(1)(E) and must comply with applicable requirements for CEMS and PEMS. Existing §117.213(c)(1)(E) and proposed new §117.240(c)(1)(E) require that the owner or operator of any unit that uses a chemical reagent for NO_x control install, calibrate, maintain, and operate a CEMS or PEMS to monitor NO_x. Also, the applicable requirements for CEMS or PEMS in existing §117.213(e) or (f), or proposed new §117.240(e) or (f) automatically apply to any CEMS or PEMS required by the section. Therefore, because the existing §117.213(g)(2) is redundant, the commission is not proposing to incorporate §117.213(g)(2) into the proposed new §117.240(g).

Finally, the commission proposes new §117.240(h) - (m) that incorporates the rule language from existing §117.213(h) - (m) applicable to the Dallas-Fort Worth ozone nonattainment area.

Section 117.245, Notification, Recordkeeping, and Reporting Requirements

The commission proposes a new §117.245 that incorporates the rule language in the existing §117.219, relating to notification, recordkeeping, and reporting requirements. Proposed new §117.245(a) - (f) incorporate the rule language from existing §117.219(a) - (f) requirements applicable to the Dallas-Fort Worth ozone nonattainment area. In addition, for proposed new §117.245(a), the commission proposes to replace the language "the startup and/or shutdown exemptions allowed under §101.222" with "the startup and/or shutdown provisions of §101.222 . . .." The reference to exemptions is not applicable to §101.222 and the proposed change is necessary to clarify proposed new §117.245(a). The commission is soliciting comments on this specific change to the language in existing §117.219(a). The commission is also soliciting comments on whether the reference to §101.222 should be removed.

Section 117.252, Final Control Plan Procedures for Reasonably Available Control Technology

The commission proposes a new §117.252 that incorporates the rule language in the existing §117.215, relating to final control plan procedures for RACT, applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.252(a) - (c) incorporates the provisions in the existing §117.215(a) - (c). Proposed new §117.252(a)(2)(A) and (B) incorporate the rule language from existing §117.215(a)(2)(A) and (B). Proposed new §117.252(a)(2)(C) incorporates the rule language from existing §117.215(a)(2)(D), and proposed new §117.252(a)(2)(D) incorporates the rule language from existing §117.215(a)(2)(C). Proposed new §117.252(a)(2)(E) incorporates the rule language from existing §117.215(a)(2)(E). In addition, for proposed new §117.252(a)(6)(B), concerning the information required in the final control plan for gas turbines with a MW rating less than 10 MW, the commission is proposing to change the word "ten" to the numeral "10.0" because this is the appropriate exemption MW rating from existing §117.205(h)(7) and proposed new §117.203(b)(7).

Proposed new §117.252 does not include existing 117.215(d), concerning the requirement to submit the control plan electronically and on hard copy using forms provided by the executive director. Existing §117.215 and proposed new §117.252 specify the content requirements for the control plans. Therefore, a mandatory format for the control plan information is not necessary. Proposed new §117.252(d) incorporates the rule language in existing §117.215(e).

In addition, the commission is not proposing a new section corresponding to the existing §117.209, concerning initial control plan procedures for RACT, for the proposed new Subchapter B, Division 2, Dallas-Fort Worth Ozone Nonattainment Area Major Sources. The requirement in §117.209 to submit an initial control plan was applicable only to the Beaumont-Port Arthur and Houston-Galveston-Brazoria ozone nonattainment areas.

Section 117.254, Final Control Plan Procedures for Attainment Demonstration Emission Specifications

The commission proposes a new §117.254 that incorporates the rule language in existing §117.216, relating to final control plan procedures for attainment demonstration emission specifications, applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.254(a) incorporates the rule language in existing §117.216(a). Proposed new §117.254(a)(1)(A) consists of the provisions in existing §117.216(a)(1)(A). Proposed new §117.254(a)(1)(B) consists of the provisions in existing §117.216(a)(1)(D). Proposed new §117.254(a)(1)(C) and (D) consist of the provisions in existing §117.216(a)(1)(B) and (C), respectively.

The commission proposes a new §117.254(a)(2) - (5) that incorporates the rule language from existing §117.216(a)(2) - (5). Proposed new §117.254(b) and (c) incorporate the rule language in existing §117.216(b) and (c), relating to final control plan procedures for attainment demonstration emission specifications, applicable to the Dallas-Fort Worth ozone nonattainment area. In addition, proposed new §117.254(b)(2)(A) and (B) exclude the references to proposed new §117.223(k) or (l) because there is no heat input information specified in these subsections in either the existing §117.223 or proposed new §117.223.

Section 117.256, Revision of Final Control Plan

The commission proposes a new §117.256 that incorporates the rule language in existing §117.217, concerning revisions of final control plans.

DIVISION 3, HOUSTON-GALVESTON-BRAZORIA OZONE NONATTAINMENT AREA MAJOR SOURCES

The commission proposes a new Chapter 117, Subchapter B, Division 3, entitled Houston-Galveston-Brazoria Eight-Hour Ozone Nonattainment Area Major Sources, that incorporates the rule language in the existing Chapter 117, Subchapter B, Division 3 applicable to major industrial, commercial, and institutional sources in the Houston-Galveston-Brazoria ozone nonattainment area.

Section 117.300, Applicability

The commission proposes a new §117.300 that incorporates the applicability rule language in the existing §117.201 applicable to the Houston-Galveston-Brazoria ozone nonattainment area.

Section 117.303, Exemptions

The commission proposes a new §117.303 that incorporates the exemptions in the existing §117.203 and §117.205 applicable to the Houston-Galveston-Brazoria ozone nonattainment area. The proposed new §117.303 consolidates the exemptions applicable to the Houston-Galveston-Brazoria ozone nonattainment area under a single section. Proposed new §117.303(a), concerning general exemptions, incorporates exemptions in existing §117.203(a)(1) - (9), (11), and (12). In addition, the provision in existing §117.203(b), regarding revocation of exemptions in existing §117.203(a)(1), (2), (7), and (8), is proposed to be merged with the applicable exemptions for clarity. Proposed new §117.303(a)(1) incorporates the exemption in the existing §117.203(a)(1) and the revocation of exemption language from §117.203(b). Proposed new §117.303(a)(2) incorporates the exemptions in the existing §117.203(a)(2) and the revocation of exemption language from §117.203(b). Proposed new §117.303(a)(3) - (6) incorporate the exemptions in the existing §117.203(a)(3) - (6). The commission proposes a new §117.303(a)(7) that incorporates the exemption in the existing §117.203(a)(7) and the revocation of exemption language from §117.203(b). Proposed new §117.303(a)(8) incorporates the exemptions in the existing §117.203(a)(8)(A) and the revocation of exemption language from §117.203(b). Proposed new §117.303(a)(9) incorporates the exemptions in existing §117.203(a)(9). Proposed new §117.303(a)(10) and (11) incorporate the exemptions in the existing §117.203(a)(11) and (12), respectively. Finally, the commission proposes a new §117.303(b)(1) - (10) that incorporates the exemptions associated with RACT in the existing §117.205(h)(1) - (10)(A).

Section 117.305, Emission Specifications for Reasonably Available Control Technology (RACT)

The commission proposes a new §117.305 that incorporates the specifications in the existing §117.205, relating to emission specifications for RACT, applicable to the Houston-Galveston-Brazoria ozone nonattainment area.

The commission proposes a new §117.305(a) - (c) consisting of the provisions in the existing §117.205(a) - (c). In addition, the commission proposes a new equation in §117.305(b)(6) that incorporates the calculation for the NO_x emission limit for gas-fired boilers and process heaters using hydrogen-rich fuel in the existing §117.205(b)(6). The proposed new equation in §117.305(b)(6) is identical in content to the existing equation in existing §117.205(b)(6). The proposed new §117.305(b)(6) presents the equation in a format consistent with other figures in Chapter 117 and provides a written description of all the terms used in the equation.

The commission proposes a new §117.305(d) consisting of the rule language in the existing §117.205(d) and (d)(1). Proposed new §117.305(e) and (f) incorporate the rule language in existing §117.205(f) and (g). Proposed new §117.305(g) incorporates the rule language in existing §117.205(i) and (i)(2).

Section 117.310, Emission Specifications for Attainment Demonstration

The commission proposes a new §117.310 that incorporates the specifications in the existing §117.206, relating to emission specifications for attainment demonstrations, applicable to the Houston-Galveston-Brazoria ozone nonattainment area.

The commission proposes a new §117.310(a) that incorporates the emission specifications in the existing §117.206(c). The catchline for subsection (a) is also proposed to be changed to Emission specifications for the Mass Emission Cap and Trade Program to more accurately reflect the purpose of the emission specifications in combination with the Mass Emission Cap and Trade Program in Chapter 101, Subchapter H, Division 3. The commission proposes a new §117.310(a)(9)(D) and (E) that incorporate and reformat the specifications for diesel engines from the existing §117.206(c)(9)(D). Proposed new §117.310(a)(9)(D) includes the emission specification from existing §117.206(c)(9)(D)(i) and proposed new §117.310(a)(9)(E) includes the emissions specifications from the existing §117.206(c)(9)(D)(ii).

The commission proposes a new §117.310(b) that incorporates the rule language regarding NO_x averaging time in the existing §117.206(d)(2).

The commission proposes a new §117.310(c), concerning related emissions, that incorporates the rule language in existing §117.206(e) applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.310(c)(1) - (3)

incorporate the rule language in existing §117.206(e)(1) - (3). Proposed new §117.310(c)(4)(A) and (B) incorporate the rule language in the existing §117.206(e)(4) and (4)(B) and (C), concerning the applicability of the CO emission specifications. In addition, for proposed new §117.310(c)(2), the commission proposes to change the emissions specification for ammonia from the word "ten" to the numeral "10." Consistent with EPA guidance, the commission normally enforces emission test and monitoring results to the same significant figures as the emission specifications. Using the numeral "10" for the ammonia emission specification would ensure consistent enforcement of the emission specification.

The commission proposes a new §117.310(d) that incorporates the rule language in existing §117.206(f), relating to compliance flexibility. Proposed new §117.310(d)(1) - (3) incorporate the rule language from existing §117.206(f)(2) - (4).

The commission proposes a new §117.310(e) that incorporates the rule language in existing §117.206(h), relating to prohibition of circumvention. Finally, proposed new §117.310(f) incorporates the rule language in existing §117.206(i), relating to operating restrictions.

Section 117.315, Alternative Plant-Wide Emission Specifications

The commission proposes a new §117.315 that incorporates the rule language in existing §117.207, relating to alternative plant-wide emission specifications, applicable to the Houston-Galveston-Brazoria ozone nonattainment area.

Proposed new §117.315(a) - (f) incorporate the rule language in existing §117.207(a) - (f), relating to compliance with plant-wide emission specifications.

Proposed new §117.315(g) incorporates the rule language from existing §117.207(g). In addition, existing §117.207(g)(1) - (3) include required calculations written in paragraph form rather than in equation form. The commission is proposing to reformat the calculations in a mathematical formula rather than the paragraph form to present the equations in a format consistent with other equations in Chapter 117 and provide a written description of all the terms used in the equation. The proposed mathematical formulas are identical in content to the existing required calculations in paragraph form. The proposed new equation in §117.315(g)(1) incorporates the calculation for the allowable NO_x emission rate for each affected boiler and process heater in the existing §117.207(g)(1). The proposed new equation in §117.315(g)(2) incorporates the calculation for the allowable NO_x emission rate for each affected stationary internal combustion engine in the existing §117.207(g)(2). The commission also proposes adding new equations to §117.315(g)(3) that incorporate the calculation for the allowable NO_x emission rate for each affected stationary gas turbine in the existing §117.207(g)(3). The proposed new §117.315(g)(3) presents the equation for determining the plant-wide emission specification for stationary gas turbines from the required calculation in existing §117.207(g)(3). Proposed new §117.315(g)(3) also includes a new equation in §117.315(g)(3) that incorporates the existing equation for calculating the in-stack NO_x concentration term used in calculating the plant-wide emission specification.

The commission proposes a new §117.315(h) that incorporates the rule language in the existing §117.207(h), relating to gas-fired boilers or process heaters using fuel that contains more than 50% hydrogen by volume. Proposed new §117.315(i) that incorporates the rule language in existing §117.207(j), concerning applicability of the section after the compliance dates for emission specifications for attainment demonstration applicable in the Houston-Galveston-Brazoria ozone nonattainment area.

Section 117.320, System Cap

The commission proposes a new §117.320 that incorporates the rule language in the existing §117.210, concerning system cap requirements for electric generation facilities in the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.320(a) - (k) incorporate the rule language in existing §117.210(a) - (k).

Also, for proposed new §117.320(b), the commission is proposing to revise the language in existing §117.210(b) that specifies "Each EGF that is subject to the NO_x emission rates of §117.206 . . .." Proposed new §117.320(b) specifies "Each EGF that is subject to §117.310 . . .." While compliance with the emission specifications in existing §117.206(c) is achieved through the Mass Emission Cap and Trade Program and an individual unit may not necessarily be required to meet the applicable emission specification in §117.206(c), an electric generating facility (EGF) subject to existing §117.206(c) is still required to comply with the system cap in existing §117.210. This proposed change for proposed new §117.320(b) would clarify the commission's intent and avoid misinterpretation of the rule requirements for an EGF subject to the Mass Emission Cap and Trade Program.

In addition, the commission proposes new equations in §117.320(c)(1) - (3) that incorporate the equations in existing §117.210(c)(1) - (3). The proposed new equations in §117.320(c)(1) - (3) present the equations in a format consistent with other equations in Chapter 117 and provide a written description of all the terms used in the equations. The proposed new equation in §117.320(c)(1) incorporates the equation for the rolling 30-day average NO_x emission cap during the months of July, August, and September in the existing §117.210(c)(1). Also, the commission proposes to revise variable (C) in the term H_i for §117.320(c)(1). The commission proposes to add the language "after the end of the adjustment period as defined in §101.350 of this title (relating to Definitions)" to the definition of variable (C). This proposed change is to clarify that the allowance for the adjustment period described in variable (D) also applies in variable (C). The commission is soliciting comment on this specific change to variable (C) in §117.320(c)(1). The proposed new equation in §117.320(c)(2) incorporates the equation for the rolling 30-day average NO_x emission cap during months other than July, August, and September in the existing §117.210(c)(2). Consistent with the change proposed for proposed new §117.320(c)(1), the commission proposes to revise variable (C) in the term H_i for §117.320(c)(2). The commission proposes to add the language "after the end of the adjustment period as defined in §101.350 of this title (relating to Definitions)" to the definition of variable (C). This proposed change is to clarify that the allowance for the adjustment period described in variable (D) also applies in variable (C). The commission is soliciting comment on this specific change to variable (C) in §117.320(c)(2). The proposed new equation in §117.320(c)(3) incorporates the equation for the NO_x maximum daily emission cap in the existing §117.210(c)(3).

For proposed new §117.320(e), the language in existing §117.210(e)(3)(B) that references existing §117.213(f) is proposed to be changed to reference proposed new §117.8100(b), because the applicable rule language from existing §117.213(f) is proposed to be incorporated in a proposed new §117.8100.

Finally, for proposed new §117.320(k), the commission proposes to replace upset period with the language "emissions event, as defined in §101.1 of this title (relating to Definitions)." This proposed change is necessary to update the rule to current terminology used by the commission.

Section 117.323, Source Cap

The commission proposes a new §117.323 that incorporates the rule language in existing §117.223, relating to source cap, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.323(a) and (b) incorporate the rule language in existing §117.223(a) and (b). In addition, the commission proposes new equations in proposed new §117.323(b) that incorporate the equations in existing §117.223(b) to present the equations in a format consistent with other equations in Chapter 117 and provide a written description of all the terms used in the equations. The proposed new equations in §117.323 include only the provisions applicable to the Houston-Galveston-Brazoria ozone nonattainment area. The proposed new equation in §117.323(b)(1) incorporates the equation for the rolling 30-day average emission cap in the existing §117.223(b)(1). The proposed new equation in §117.323(b)(2) incorporates the equation for the rolling 30-day average NO_x emission cap in the existing §117.223(b)(2).

The commission proposes new §117.323(c) - (g) that incorporate the rule language in existing §117.223(c) - (g). Proposed new §117.323(h) incorporates the rule language in existing §117.223(i) and (i)(1). Proposed new §117.323(i) - (k) incorporate the rule language in existing §117.223(j) - (l), respectively. Finally, for proposed new §117.323(j), the commission proposes to replace upset period with the language "emissions event, as defined in §101.1 of this title (relating to Definitions)." This proposed change is necessary to update the rule to current terminology used by the commission.

Section 117.325, Alternative Case Specific Specifications

The commission proposes a new §117.325 that incorporates the rule language in the existing §117.221, relating to alternative case specific specifications, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.325(a) and (b) incorporate the provisions in existing §117.221(a) and (b). In addition, proposed new §117.325(a) omits the existing §117.221(a)(4) because the Engineering Services Team no longer exists within the TCEQ.

Section 117.330, Operating Requirements

The commission proposes a new §117.330 that incorporates the rule language in existing §117.208, relating to operating requirements, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.330(a) - (d) incorporate the rule language in existing §117.208(a) - (d). In addition, the commission is concurrently proposing a new §117.8140(b) that incorporates the engine testing requirements in the existing §117.208(d)(7). Therefore, the engine testing requirements in existing §117.208(d)(7) have been omitted from the proposed new §117.330(d)(7) and replaced with a reference to the proposed new §117.8140(b).

Section 117.335, Initial Demonstration of Compliance

The commission proposes a new §117.335 that incorporates the rule language in existing §117.211, relating to initial demonstration of compliance, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.335(a) - (d) incorporate the rule language in existing §117.211(a) - (d). Also, for proposed new §117.335(a), the commission is proposing to revise the language in existing §117.211(a) that specifies ". . . all units which are subject to the emission limitations of this division . . ." must be tested. Proposed new §117.335(a) specifies ". . . any unit subject to §117.305 or §117.310 of this title . . ." must be tested. While compliance with the emission specifications in existing §117.206(c) is achieved through the Mass Emission Cap and Trade Program and an individual unit may not necessarily be required to meet the applicable emission specification in §117.206(c), units subject to existing §117.206(c) are still required to be tested according to existing §117.211. Similarly, for proposed new §117.335(b), the commission proposes to revise the language to specify initial compliance with the requirements of this division instead of initial compliance with the emission limits of this division. These proposed changes for proposed new §117.335(a) and (b) would clarify the commission's intent and avoid misinterpretation of the rule requirements for units subject to the Mass Emission Cap and Trade Program.

The commission is concurrently proposing a new §117.8000 that incorporates the requirements in the existing §117.211(e). Therefore, the commission proposes a new §117.335(e) that replaces specific requirements from existing §117.211(e) with a reference to the proposed new §117.8000. In addition, while existing §117.211(a) and proposed new §117.335(a) specify that units that inject urea or ammonia for NO_x control must be tested for ammonia emissions, existing §117.211(e) does not specify the methods to be used for the required ammonia initial demonstration of compliance. Proposed new §117.8000 includes a requirement that specifies the methods required for ammonia testing during the initial demonstration of compliance. Specific discussion related to this proposed change is included in the section-by-section discussion associated with proposed new §117.8000.

Proposed new §117.335(f) incorporates the rule language from existing §117.211(f), regarding initial demonstration of compliance for units operating with CEMS or PEMS. Finally, the commission is concurrently proposing a new §117.8010 that incorporates the report content requirements in the existing §117.211(g). Therefore, the proposed new §117.335(g) omits the compliance stack reports content requirements and references proposed new §117.8010.

Section 117.340, Continuous Demonstration of Compliance

The commission proposes a new §117.340 that incorporates the rule language and requirements in existing §117.213 and §117.214 applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.340(a) incorporates the rule language concerning totalizing fuel flow meters in existing §117.213(a).

The commission proposes a new §117.340(b) that incorporates the rule language in existing §117.213(b), relating to O_2 monitors. In addition, existing §117.213(b)(1)(B)(i) requires O_2 monitors on process heaters greater than or equal to 100 MMBtu/hr, and clause (ii) requires O_2 monitors on process heaters greater than or equal to 200 MMBtu/hr, except as provided in existing §117.213(f). Because existing §117.213(b)(1)(B)(i) and (ii) are overlapping requirements, the proposed new §117.340(b)(1)(B) incorporates both existing §117.213(b)(1)(B)(i) and (ii) into a single requirement for O_2 monitors on process heaters greater than or equal to 100 MMBtu/hr, except as provided in subsection (g).

The commission proposes a new §117.340(c) that incorporates the requirements in the existing §117.213(c), relating to NO_x

monitors. Proposed new §117.340(c)(1)(A) and (B) incorporate the requirements in the existing §117.213(c)(1)(A) and (B). Proposed new §117.340(c)(1)(C) - (H) incorporate the requirements in the existing §117.213(c)(1)(D) - (I).

The commission proposes a new §117.340(c)(2) and (3) that incorporate the requirements in the existing §117.213(c)(2) and (3). In addition, for proposed new §117.340(c)(3), the commission proposes a new §117.340(c)(3)(E) to add an additional option for substitute emissions compliance data during periods when the NO_x monitor is off-line. The proposed new §117.340(c)(3)(E)(i) specifies that for monitor downtime periods less than 24 consecutive hours, the owner or operator shall substitute the maximum block one-hour NO_x emission rate, in pounds per million British thermal units (lb/MMBtu), from the previous 24 operational hours of the monitor. Proposed new §117.340(c)(3)(E)(ii) specifies that for monitor downtime periods equal to or greater than 24 consecutive hours, the owner or operator shall substitute the maximum block one-hour NO_x emission rate, in lb/MMBtu, from the previous 720 operational hours of the monitor. Proposed new §117.340(c)(3)(E)(iii) specifies that if the fuel flow or stack exhaust monitor and the NO_x monitor are simultaneously off-line, the owner or operator shall use the maximum block one-hour NO_x pounds per hour emission rate for the substitute data in the proposed new §117.340(c)(3)(E)(i) and (ii) in lieu of the lb/MMBtu emission rate. The provisions in proposed new §117.340(c)(3)(E) are optional; however, the proposed new data substitution procedures are more consistent with the requirements of the Mass Emissions Cap and Trade Program in the Houston-Galveston-Brazoria ozone nonattainment area. The commission is soliciting comments on this specific change regarding the additional option for data substitution procedures.

The commission proposes a new §117.340(d) that incorporates the rule language and ammonia monitoring requirements in the existing §117.214(a)(1)(D). The proposed §117.340(d) specifies that the owner or operator of units subject to the ammonia emission specifications in the proposed new §117.310(c)(2) shall comply with the ammonia monitoring requirements of the proposed new §117.8130. The specific ammonia monitoring procedures in existing §117.214(a)(1)(D) are incorporated in the proposed new §117.8130.

The commission proposes a new §117.340(e) that incorporates the requirements in the existing §117.213(d) relating to CO monitoring. The specific requirements and method for CO monitoring in the existing §117.213(d)(1) and (2) appear in the proposed new §117.8120, and subsequently have been omitted from the proposed new §117.340(e) and replaced with a reference to the proposed new §117.8120.

The commission proposes a new §117.340(f), concerning requirements for CEMS. The commission is concurrently proposing a new §117.8100(a) that incorporates the general requirements for CEMS in the existing §117.213(e)(1) - (3), (5), and (6). Therefore, proposed new §117.340(f) omits existing §117.213(e)(1) - (3), (5), and (6) and references proposed new §117.8100(a) in proposed new §117.340(f)(1). Proposed new §117.340(f)(2) incorporates the rule language and CEMS requirements in existing §117.213(e)(4) that are specific to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.340(f)(2)(A) incorporates the rule language regarding monitoring of bypass stacks from existing §117.213(e)(4)(A). Proposed new §117.340(f)(2)(B) incorporates the rule language regarding monitoring of exhaust streams that vent to a common stack from existing §117.213(e)(4)(C).

The commission proposes a new §117.340(g) that incorporates the rule language in the existing §117.213(f), relating to requirements for PEMS. Proposed new §117.340(g)(1) incorporates the rule language from existing §117.213(f)(1). The commission is concurrently proposing a new §117.8100(b) that incorporates the general requirements for PEMS in the existing §117.213(f)(2) - (7). Therefore, the proposed new §117.340(g) omits existing §117.213(f)(2) - (7) and proposed new §117.340(g)(2) references proposed new §117.8100(b).

The commission proposes a new §117.340(h) concerning testing requirements for stationary gas engines. For proposed new §117.340(h), the commission is proposing to revise the rule language "stationary gas engine subject to the emission specifications of this division" to specify "stationary gas engine subject to §117.305 of this title." The commission is concurrently proposing a new §117.8140(a) that incorporates the engine testing requirements in existing §117.213(g)(1). Therefore, the proposed new §117.340(h) omits specific testing procedures in existing §117.213(g)(1) and references proposed new §117.8140(a). In addition, proposed new §117.340(h) also specifies that the owner or operator of any stationary internal combustion engines subject to proposed new §117.310 that are not equipped with NO_x CEMS or PEMS shall test the engines for NO_x and CO emissions as specified in proposed new §117.8140(a) and (b). This proposed change incorporates the testing requirements for engines from existing §117.214(b)(2). In addition, as previously indicated in this preamble, the requirement in existing §117.213(g)(2), regarding installation of CEMS or PEMS engines that use a chemical reagent for reduction of NO_x, is redundant and the commission is not proposing to incorporate §117.213(g)(2) into the proposed new §117.340(h).

The commission proposes a new §117.340(i) - (n) that incorporate the rule language in the existing §117.213(h) - (m), respectively. Proposed new §117.340(o) incorporates rule language from existing §117.214(b). Proposed new §117.340(o)(1) incorporates rule language from existing §117.214(b)(1), and proposed new §117.340(o)(2) incorporates the rule language from existing §117.214(b)(3). The commission proposes a new §117.340(p) that incorporates the requirements of the existing §117.214(c), concerning provisions for emission allowances.

The provisions in existing §117.214(a)(1)(A) - (C), concerning monitoring requirements for NO_x, CO, and totalizing fuel flow meters, are redundant with existing requirements in §117.213 and proposed new §117.340. Therefore, existing §117.214(a)(1)(A) - (C) are not proposed to be incorporated in the proposed new §117.340. Similarly, the requirement in existing §117.214(a)(2), concerning run time meters for diesel engines claimed exempt under existing §117.203(a)(6)(D), (11), or (12), is redundant with the requirement in existing §117.213(i) and proposed new §117.340(j). Therefore, existing §117.214(a)(2) is not proposed to be incorporated in the proposed new §117.340.

Section 117.345, Notification, Recordkeeping, and Reporting Requirements

The commission proposes a new §117.345 that incorporates the rule language in the existing §117.219, relating to notification, recordkeeping, and reporting requirements, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.345(a) - (f) incorporate the rule language from existing §117.219(a) - (f), respectively. In addition, for proposed new §117.345(a), the commission proposes to replace the language "the startup and/or shutdown exemptions allowed under §101.222" with "the startup and/or shutdown provisions of §101.222 . . .." The reference to exemptions is not applicable to §101.222 and the proposed change is necessary to clarify proposed new §117.345(a). The commission is soliciting comments on this specific change to the language in existing §117.219(a). The commission is also soliciting comments on whether the reference to §101.222 should be removed. Finally, the commission proposes a new §117.345(f)(11) that incorporates the ammonia recordkeeping requirements from existing §117.214(a)(1)(D)(v).

Section 117.350, Initial Control Plan Procedures

The commission proposes a new §117.350 that incorporates the rule language in the existing §117.209, relating to initial control plan procedures, applicable to the Houston-Galveston-Brazoria nonattainment area.

Section 117.352, Final Control Plan Procedures for Reasonably Available Control Technology

The commission proposes a new §117.352 that incorporates the requirements in the existing §117.215, relating to final control plan procedures for RACT, applicable to the Houston-Galveston-Brazoria ozone nonattainment area.

Proposed new §117.352(a) incorporates the rule language in existing §117.215(a). Proposed new §117.352(a)(2)(A), (B), and (E) incorporate the rule language in existing §117.215(a)(2)(A), (B), and (E), respectively. Proposed new §117.352(a)(2)(C) incorporates the rule language in existing §117.215(a)(2)(D), and proposed new §117.352(a)(2)(D) incorporates the rule language in existing §117.215(a)(2)(C). Proposed new §117.352(a)(3) - (6) incorporate the rule language in existing §117.215(a)(3) - (6), respectively. In addition, for proposed new §117.352(a)(6)(B), concerning the information required in the final control plan for gas turbines with a MW rating less than 10 MW, the commission is proposing to change the word "ten" to the numeral "10.0" because this is the appropriate exemption MW rating from existing §117.205(h)(7) and proposed new §117.303(b)(7).

The commission proposes a new §117.352(b) and (c) that incorporate the rule language in existing §117.215(b) and (c), respectively. Proposed new §117.352 does not include existing 117.215(d), concerning the requirement to submit the control plan electronically and on hard copy using forms provided by the executive director. Existing §117.215 and proposed new §117.352 specify the content requirements for the control plans. Therefore, a mandatory format for the control plan information is not necessary. Finally, the commission proposes a new §117.352(d) that incorporates rule language in existing §117.215(e), relating to report submittal dates.

Section 117.354, Final Control Plan Procedures for Attainment Demonstration Emission Specifications

The commission proposes a new §117.354 that incorporates the rule language in the existing §117.216, relating to final control plan procedures for attainment demonstration emission specifications, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.354(a) incorporates the rule language in the existing §117.216(a). Proposed new §117.354(a)(1)(A) incorporates the rule language in existing §117.216(a)(1)(E), and proposed new §117.354(a)(1)(B) incorporates the rule language in existing §117.216(a)(1)(C). Existing §117.216(a)(1)(A), (B), and (D) are not applicable to the Houston-Galveston-Brazoria ozone nonattainment area and are not proposed to be incorporated in the proposed new §117.354. Proposed new §117.354(a)(2) - (6) incorporate the rule language from existing §117.216(a)(2) - (6). For proposed new §117.354(a)(5), the commission proposes to remove the language "the emission specification of." As previously discussed in this preamble, this change is necessary to clarify the commission's intent regarding units subject to the Mass Emission Cap and Trade Program.

Existing §117.216(b) is not proposed to be incorporated in the proposed new §117.354 because the source cap option in existing §117.223 is not a compliance option for sources in the Houston-Galveston-Brazoria ozone nonattainment area subject to existing §117.206(c) and the Mass Emission Cap and Trade Program. Finally, the commission proposes a new §117.354(b) that incorporates the rule language in existing §117.216(c), relating to report submittal dates.

Section 117.356, Revision of Final Control Plan

The commission proposes a new §117.356 that incorporates the requirements in the existing §117.217, relating to revisions of final control plans, applicable to the Houston-Galveston-Brazoria ozone nonattainment area.

DIVISION 4, DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MAJOR SOURCES

The commission is proposing a new Subchapter B, Division 4, entitled Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources, that would include new rules applicable to any major stationary ICI sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area. The definition of a major source of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area is in proposed new §117.10(29) and includes any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit 50 tpy of NO_x. These proposed new rules are one part of the commission's Dallas-Fort Worth eight-hour ozone attainment demonstration and are necessary for the area to demonstrate attainment.

Section 117.400, Applicability

Proposed new §117.400, concerning applicability, specifies that the new Subchapter B, Division 4 applies to the following unit types at major ICI stationary sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area: ICI boilers and process heaters; stationary gas turbines; stationary internal combustion engines; duct burners used in turbine exhaust ducts; lime kilns; metallurgical heat treating furnaces and reheat furnaces; incinerators; glass, fiberglass, and mineral wool melting furnaces; fiberglass and mineral wool curing and forming ovens; natural gas-fired ovens and heaters; natural gas-fired organic solvent, printing ink, clay, brick, ceramic tile, calcining, and vitrifying dryers; brick and ceramic kilns; electric arc melting furnaces used in steel production; and lead smelting reverberatory and blast (cupola) furnaces.

Section 117.403, Exemptions

Proposed new §117.403 specifies the unit types, sizes, or uses that would be exempted from the requirements of this division. Units that the unit type, maximum rated capacity, or specific use would be technically or economically infeasible to comply with the specifications or are regulated under another division are exempted from the provisions of this division.

Proposed new §117.403(a) specifies those units exempt from the division, except as specified in proposed new §§117.440(i), 117.445(f)(4) and (9), 117.450, and 117.454. The exceptions to the proposed exemptions are related to monitoring, recordkeeping, and control plan requirements associated with exempted units. Proposed new §117.403(a)(1) specifies that ICI boilers or process heaters with a maximum rated capacity of 2.0 MMBtu/hr or less would be exempted. This exemption level is proposed because units with a maximum rated capacity of 2.0 MMBtu/hr or less are already regulated under existing Subchapter B, Division 1, which is proposed to be incorporated in proposed new Subchapter E, Division 3.

Proposed new §117.403(a)(2) specifies an exemption for heat treating furnaces and reheat furnaces less than 20 MMBtu/hr. This exemption level is consistent with the exemption in existing §117.203(a)(3) for similar sources in the Houston-Galveston-Brazoria area and is proposed for the Dallas-Fort Worth eight-hour ozone nonattainment area due to the low level of NO_x emissions from units of this size and the impracticality of installing and maintaining NO_x controls on such units.

Proposed new §117.403(a)(3) specifies exemptions for flares and incinerators with a maximum rated capacity of 40 MMBtu/hr due to the low level of NO_x emissions from these units and the impracticality of installing and maintaining NO_x controls on such units and is consistent with existing exemptions in the specifications for the Houston-Galveston-Brazoria area of §117.203(a)(4). In addition, proposed new §117.403(a)(3) specifies that pulping liquor recovery furnaces, sulfur recovery units, sulfuric acid regeneration units, molten sulfur oxidation furnaces, and sulfur plant reaction boilers are also exempt. This addition is consistent with the existing exemptions in the specifications for the Houston-Galveston-Brazoria area for units that commingle fuel and process chemicals and are not large sources of NO_x emissions.

Proposed new §117.403(a)(4) specifies dryers, heaters, or ovens with a maximum rated capacity of 2.0 MMBtu/hr or less are exempt. This exemption level is proposed due to the relatively small contribution of NO_x emissions from units of this size and the impracticality of installing and maintaining NO_x controls on such units.

Proposed new §117.403(a)(5) specifies dryers, heaters, or ovens fired on fuels other than natural gas are exempt. This exemption is proposed due to the limited number, if any, of these unit types fired on fuels other than natural gas and their insignificant contribution to NO_x levels in the area. Proposed new §117.403(a)(6) specifies that any glass, fiberglass, or mineral wool melting furnaces with a maximum rated capacity of 2.0 MMBtu/hr or less are exempt from the specifications of this division. This exemption level is proposed due to the relatively small contribution to NO_x emissions in the area from units of this size and the impracticality of installing and maintaining NO_x controls on such units.

In addition, the following stationary internal combustion engines and stationary gas turbines would be exempt in the proposed new §117.403(a)(7)(A) - (G): engines and stationary gas turbines used in research and testing; used for purposes of performance verification and testing; used solely to power other engines or gas turbines during startups; used 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); used in response to and during the existence of any officially declared disaster or state of emergency; used directly and exclusively by the owner of operator for agricultural operations necessary for the growing of crops or raising of fowl or animals; or used as chemical processing gas turbines. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after June 1, 2007, would not be eligible for the emergency use exemption in proposed §117.403(a)(7)(D). These exemptions are proposed due to the relatively small NO_x emissions contribution in the area from these sources due to their limited use or the impracticality of using NO_x emissions controls during such limited operating times. The exemptions in proposed new §117.403(a)(7)(A) - (G) are similar to existing exemptions in the Houston-Galveston-Brazoria area.

Proposed new §117.403(a)(8) specifies an exemption for any stationary diesel engine placed into service before June 1, 2007, that operates less than 100 hours per year, based on a rolling 12-month average, and has not been modified, reconstructed, or relocated on or after June 1, 2007. Proposed new §117.403(a)(9) exempts any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after June 1, 2007, that operates less than 100 hours per year, in other emergency situations, and meets the corresponding emission standard for non-road engines listed in 40 Code of Federal Regulations (CFR) §89.112(a), Table 1 (October 23, 1998) and in effect at the time of installation, modification, reconstruction, or relocation. These exemptions are consistent with existing exemptions applicable in the Houston-Galveston-Brazoria ozone nonattainment area for emergency back-up diesel engines and are proposed for the Dallas-Fort Worth eight-hour ozone nonattainment area because of the limited use of emergency back-up diesel engines.

Proposed new §117.403(a)(10) exempts boilers and industrial furnaces that were regulated as existing facilities by the EPA, 40 CFR Part 266, Subpart H, as was in effect on June 9, 1993. This exemption is consistent with existing exemptions applicable in the Houston-Galveston-Brazoria ozone nonattainment area and is necessary to avoid overlapping regulatory requirements for cement kilns regulated by proposed new Chapter 117, Subchapter E, Division 2.

Finally, proposed new §117.403(a)(11) exempts brick or ceramic kilns with a maximum rated capacity less than 5.0 MMBtu/hr. This exemption is proposed due to the relatively small NO_x emissions contribution in the area from these smaller kilns.

The proposed §117.403(b), concerning IOP exemptions, exempts stationary, reciprocating internal combustion engines with a maximum rated capacity of less than 300 horsepower (hp) from the emission specification in proposed new §117.410(a). This exemption is consistent with the current exemption applicable to the engines subject to existing §117.206(b)(3) and is necessary to ensure that engines not previously subject to existing §117.206(b)(3) are inadvertently made subject to the emission specifications in proposed §117.410(a). Proposed new §117.403(b) also specifies that the specifications of §117.410(a) no longer apply to any stationary, reciprocating internal combustion engine subject to the emission specifications of §117.410(b) after the compliance date specified in §117.9030(b). This exemption is proposed to prevent units subject to the 5% IOP emission specifications from being regulated by two overlapping requirements once the more stringent emission specifications in proposed §117.410(b) become applicable.

Section 117.410, Emission Specifications for Eight-Hour Attainment Demonstration

The commission proposes a new section §117.410, relating to Emission Specifications for Eight-Hour Attainment Demonstration. The new §117.410 establishes proposed NO_x emissions specifications for units in the Dallas-Fort Worth eight-hour ozone nonattainment area that would be subject to this rulemaking. Proposed new §117.410(a), concerning emission specifications for increment of progress, incorporates the emissions specifications for gas-fired engines with a maximum capacity greater than 300 hp established under the 5% IOP from the existing one-hour specifications in existing §117.206(b)(3) into the proposed eight-hour attainment demonstration. The 5% IOP specifications in existing §117.206(b)(3) apply to all nine counties in the Dallas-Fort Worth eight-hour ozone nonattainment area and are therefore more consistent with the proposed new Subchapter B, Division 4. The existing emission specifications and rule language from existing §117.206(b)(3) are proposed to be incorporated in proposed new §117.410(a) without change, except for non-substantive changes associated with reformatting and renumbering.

Proposed new §117.410(b) includes the proposed new emission specifications for the Dallas-Fort Worth eight-hour ozone attainment demonstration. Proposed new §117.410(b)(1) specifies a NO_x emission specification for non-utility gas-fired boilers depending on maximum capacity. Gas-fired boilers with a maximum rated capacity equal to or greater than 100 MMBtu/hr would be limited to 0.020 lb/MMBtu. Gas-fired boilers with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr would be limited to 0.030 lb/MMBtu. The proposed emission limit for gas-fired boilers with a maximum rated capacity less than 40 MMBtu/hr is 0.036 lb/MMBtu, or alternatively, 30 parts per million by volume (ppmv), at 3.0% O_2, dry basis. The proposed 0.020 lb/MMBtu emission specification for gas-fired boilers greater than 100 MMBtu/hr is expected to require the installation of SCR. Owners or operators of gas-fired boilers equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, may be able meet the 0.030 lb/MMBtu emission specification through combustion modifications, such as installation of low-NO_x burners or burner modifications; however, SCR may be required in some cases to meet this proposed emission specification. The proposed emission specification of 0.036 lb/MMBtu for boilers less than 40 MMBtu/hr is expected to be achievable through installation of low-NO_x burners or burner modifications.

Proposed new §117.410(b)(2) specifies a NO_x emission specification of 2.0 pounds per 1,000 gallons of liquid burned for liquid-fired boilers. The commission anticipates that this emission specification is achievable through installation of SCR.

Proposed new §117.410(b)(3) includes NO_x emission specifications of 0.025 lb/MMBtu for process heaters with a maximum rated capacity equal to or greater than 40 MMBtu/hr, and 0.036 lb/MMBtu (or alternatively, 30 ppmv, at 3.0% O_2, dry basis) for process heaters with a maximum rated capacity less than 40 MMBtu/hr. SCR may be necessary for process heaters with a maximum rated capacity equal to or greater than 40 MMBtu/hr to comply with the proposed 0.025 lb/MMBtu emission specification. Owners or operators of gas-fired process heaters with maximum rated capacities less than 40 MMBtu/hr may be required to install low-NO_x burners or make other combustion modifications to comply with the proposed 0.036 lb/MMBtu emission specification. No liquid-fired process heaters were identified in the inventory in the Dallas-Fort Worth eight-hour ozone area; however, SCR may be necessary for a liquid-fired process heater to comply with the proposed emission specification.

Proposed new §117.410(b)(4) provides NO_x emission specifications for stationary reciprocating internal combustion engines. The proposed language in §117.410(b)(4)(A) and (B) would establish NO_x emission specifications for stationary, gas-fired rich-burn and lean-burn, reciprocating internal combustion engines. Gas-fired engines fired on landfill gas are proposed to be limited to 0.60 grams per horsepower-hour (g/hp-hr) and all other gas-fired engines are proposed to be limited to 0.50 g/hp-hr. Nonselective catalytic reduction (NSCR) is expected to be the primary control technology for rich-burn gas-fired engines. In some cases, the addition of a secondary catalyst module may be required to meet the proposed emission specification. For lean-burn gas-fired engines, the commission has identified two possible control methodologies to achieve the 0.50 g/hp-hr emission standard. One control technology available for lean-burn engines is the application of an exhaust gas recirculation (EGR) kit combined with NSCR control. While NSCR is not normally applied to lean-burn engines, the use of the EGR kit reduces exhaust gas O_2 and allows NSCR to be installed. It is possible that owners or operators of some lean-burn engines may not be able to apply EGR coupled with NSCR. In these cases, SCR may be necessary to achieve the proposed emission specification. The commission has identified only one engine in the Dallas-Fort Worth eight-hour ozone nonattainment area that is fired on land-fill gas. The proposed emission specification of 0.60 g/hp-hr is expected to be achievable through combustion modifications.

Proposed new §117.410(b)(4)(C) would limit stationary, dual-fuel, reciprocating internal combustion engines to 0.50 g/hp-hr. There are three possible dual-fuel engines identified at major sources in the Dallas-Fort Worth eight-hour ozone nonattainment area. The commission anticipates that SCR may be necessary to comply with the proposed 0.50 g/hp-hr emission specification. The commission is soliciting comments on this limit and the possibility of SCR being required to meet this emission specification, particularly in the case of engines fired on gas derived from waste treatment operations.

The proposed new §117.410(b)(4)(D) would establish NO_x emission specifications for stationary diesel reciprocating internal combustion engines placed into service before June 1, 2007, and that have not been modified, reconstructed, or relocated on or after June 1, 2007, as the lower of 11.0 g/hp-hr or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data. In addition, for proposed new §117.410(b)(4)(D), modification, reconstruction, and relocated would be defined consistent with existing §117.206(c)(9)(D)(i).

The proposed new §117.410(b)(4)(E) would establish NO_x emission specifications for stationary diesel reciprocating internal combustion engines based on engine hp rating and the date the engine was installed, modified, reconstructed, or relocated. These emission specifications are similar to the emission specifications for stationary diesel engines subject to Subchapter B, Division 3 in the Houston-Galveston-Brazoria nonattainment area; however, the commission is not proposing to require engines to meet previous emission specifications for which the dates have passed. The proposed new §117.410(b)(4)(E) would establish the NO_x emission specifications for stationary diesel engines installed, modified, reconstructed, or relocated on or after June 1, 2007. The proposed emission specifications in §117.410(b)(4)(E) are consistent with the emission specifications for stationary diesel engines in the Houston-Galveston-Brazoria nonattainment area that have not yet passed by the time of the anticipated adoption date of this rule.

The commission expects that the majority of stationary diesel engines at major sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area would qualify for exemption under §117.403(a)(9). When owners or operators modify, reconstruct, or relocate existing stationary diesel engines on or after June 1, 2007, if used exclusively in emergency situations, these engines would continue to be exempt from the new emission specifications, but would be required to meet the EPA Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of installation, modification, reconstruction, or relocation. This would ensure that as turnover of older, higher-emitting stationary diesel engines occurs, the replacements would be cleaner engines. For engines that do not qualify for exemption, the commission does not anticipate that engines placed into service prior to June 1, 2007, would require combustion modifications to meet the 11.0 g/hp-hr emission specification. The cost of combustion modifications to stationary diesel engines to meet the emission standards proposed in §117.410(b)(4)(D) is expected to be near the cost of a new engine; therefore, the commission anticipates that for engines placed into service on or after June 1, 2007, the owner or operator would likely purchase new equipment rather than retrofit or modify existing equipment.

Proposed new §117.410(b)(5) would establish NO_x emission specifications for stationary gas turbines. Stationary gas turbines rated at 10 MW or greater would be limited to 0.032 lb/MMBtu; stationary gas turbines rated at 1.0 MW or greater, but less than 10 MW, would be limited to 0.15 lb/MMBtu; and stationary gas turbines less than 1.0 MW would be limited to 0.26 lb/MMBtu. The proposed new §117.410(b)(6) would specify that duct burners used in turbine exhaust ducts would be limited to the corresponding gas turbine emission specifications of §117.410(b)(5). Compliance with the proposed emission specification of 0.032 lb/MMBtu for stationary gas turbines and duct burners used in turbine exhaust ducts may require the installation of SCR. The proposed emission specifications for all stationary gas turbines less than 10 MW and duct burners used in associated turbine exhaust ducts are expected to be achievable through combustion modifications such as water or steam injection or other modifications.

The proposed new §117.410(b)(7) would establish emission specifications for lime, brick, and ceramic kilns in the Dallas-Fort Worth eight-hour ozone nonattainment area. Lime kilns would be limited to 3.1 pounds per ton of calcium oxide (CaO) produced. The 3.1 lb/ton CaO limit for lime kilns is proposed for the lime calcining kilns in the Dallas-Fort Worth eight-hour ozone nonattainment area whose production rates and operations are not compatible with the existing one-hour 0.66 pounds per ton CaO limit derived for lime recovery furnaces at pulp and paper mills in the Houston-Galveston-Brazoria area. This emission rate is based on good combustion practices and proper kiln operation, possibly combined with low-NO_x burners, as specified by the EPA as Best Available Control Techniques (BACT) for lime kilns. The commission is soliciting comments on the technical and economic feasibility of the proposed limit for lime kilns.

Proposed new §117.410(b)(7)(B) would establish a NO_x emission specification of 0.175 pounds per ton of product for brick and ceramic kilns. Compliance with this proposed emission specification is anticipated to be achievable through combustion and process modifications, installation of low-NO_x burners, or staged combustion, or some combination of these control measures.

Proposed new §117.410(b)(8) would establish NO_x emission specifications for metallurgical furnaces. Heat treating furnaces would be limited to 0.087 lb/MMBtu under subparagraph (A), and reheat furnaces would be limited to 0.10 lb/MMBtu under subparagraph (B). The proposed emission specification for heat-treat furnaces is based on the emission specifications for heat treating in the Houston-Galveston-Brazoria ozone nonattainment area, and is expected to be achievable through combustion modifications or installation of low-NO_x burners combined with flue gas recirculation (FGR). The proposed emission specification for reheat furnaces is based on the permitted BACT limits for similar units and is anticipated to require the owners or operators of affected units to make combustion modifications, install ultra low-NO_x burners, and possibly install FGR units to meet the specifications.

Proposed new subparagraph (C) includes a new NO_x emission specification for electric arc furnaces used in steel production, and proposed new subparagraph (D) includes a new emission specification for lead smelting blast (cupola) and reverberatory furnaces that are used in conjunction. The proposed new emission specification for electric arc furnaces is 0.30 pounds per ton of product. Owners or operators would be required to use oxy-firing and combustion and process modifications to meet this proposed emission specification. The proposed new emission specification for lead smelting blast and reverberatory furnaces used in conjunction is the combined rate of 0.45 pounds per ton of product. Owners or operators may be required to use a combination of low-NO_x burners and FGR or possibly post-combustion controls such as SNCR to achieve this emission specification.

Proposed new §117.410(b)(9) would establish NO_x emission specifications for incinerators and provides two options. The first option is to achieve an 80% reduction from the daily NO_x emissions reported to the Industrial Emissions Assessment Section for the calendar year 2000 Emissions Inventory. To ensure that this emission specification would result in a real 80% reduction in actual emissions, a consistent methodology must be to calculate the 80% reduction. The second option is to comply with a 0.030 lb/MMBtu emission specification. While these proposed emission specifications for incinerators may be achievable through installation of low-NO_x burners or making other combustion modifications, SCR may be necessary to achieved the 80% reduction or the 0.030 lb/MMBtu emission specification.

Proposed new §117.410(b)(10) would establish emission specifications for glass and fiberglass melting furnaces. Container glass melting furnaces would be limited to 1.30 pounds per ton of glass pulled under proposed subparagraph (A). Mineral wool-type electric fiberglass melting furnaces would be limited to 1.45 pounds per ton of product pulled under proposed subparagraph (B). Mineral wool-type fiberglass regenerative furnaces would be limited to 1.45 pounds per ton of product pulled under proposed subparagraph (C). The limit for container glass melting furnaces is based on the Consent Decree between the EPA and Saint Gobain Containers specifying the use of oxy-fired furnaces. The emission specifications for the fiberglass melting furnaces are based on a widely accepted BACT limit of 1.4 pounds per ton for these furnaces and are supported by commission staff analysis of data provided from informal stakeholder comments. The commission anticipates that most of the affected furnaces would require low-NO_x burners, oxy-firing, SCR, SNCR, or a combination of these control technologies to reach the proposed emission specifications. Informal stakeholder comments indicate that SCR is not an appropriate control technology for glass and fiberglass melting furnaces due to wide variations in furnace operating temperatures. In addition, NO_x emissions from glass melting furnaces, especially electric glass melting furnaces, are typically thermal NO_x emissions formed from the combustion air and high operating temperatures of the furnace and would therefore require oxy-firing for compliance.

Proposed new §117.410(b)(11), (12), and (13) would establish a 0.036 lb/MMBtu NO_x emission specification for the following units, respectively: gas-fired curing and forming ovens used for the production of mineral wool-type or textile-type fiberglass; natural gas-fired ovens and heaters used in industrial processes; and organic, solvent, printing, clay, brick, and ceramic tile dryers fired on natural gas. These emission specifications are anticipated to be achieved through combustion modifications, such as burner modifications or installation of low-NO_x burners.

Proposed new §117.410(b)(14) provides an alternative to the emission specifications in paragraphs (1) - (13) of §117.410(b) for units with an annual capacity factor of 0.0383 or less. The alternative NO_x emission specification for qualifying units would be 0.060 lb/MMBtu. This low annual capacity factor and alternative emission specification are consistent with a similar provision specified for the Houston-Galveston-Brazoria ozone nonattainment area in existing §117.206(c)(2). The capacity factor as of December 31, 2000, must be used to determine whether the unit is eligible for the alternative emission specification. A 12-month rolling average must be used to determine the annual capacity factor for units placed into service after December 31, 2000.

Proposed new §117.410(c), concerning NO_x averaging time, specifies the averaging times for compliance with the emission specifications. Proposed new §117.410(c)(1) specifies the averaging times for units equipped with CEMS or PEMS and provides three options under proposed subparagraphs (A), (B), and (C). Proposed subparagraph (A) specifies a rolling 30-day average, in the units of the applicable standard. Proposed subparagraph (B) specifies a block one-hour average basis, in the units of the applicable standard. Proposed subparagraph (C) specifies a block one-hour average, in pounds per hour, for boilers and process heaters, calculated based on the maximum rated capacity and the applicable emission specification. For units not equipped with CEMS or PEMS, proposed new §117.410(c)(2) requires the averaging time to be a block one-hour average in the units of the applicable standard, but allows the emission specifications for boilers and process heaters to be applied in pounds per hour as specified in proposed new §117.410(c)(1)(C).

Proposed new §117.410(d) would establish NO_x emission specifications for related emissions from any unit subject to the emission specifications in §117.410(a) or (b). This is necessary to ensure that the NO_x reduction strategies of this proposed rulemaking do not result in an excessive increase in emissions of other pollutants. Proposed new §117.410(d)(1) establishes a CO emission specification of 400 ppmv at 3% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines) on a rolling 24-hour averaging period for units equipped with CEMS and PEMS for CO, and on a one-hour average for units not equipped with CEMS or PEMS. Proposed new §117.410(d)(2) specifies that units that inject urea or ammonia into the exhaust stream for NO_x control must meet a 10 ppmv ammonia emission specification. The 10 ppmv ammonia emission specification is corrected to 3.0% O_2 for boilers and process heaters, 15% O_2 for stationary gas turbines and gas-fired lean-burn engines, 7.0% O_2 for incinerators, and 3.0% O_2 for all other units. The specified averaging time for the ammonia emission specification is on a rolling 24-hour averaging period for units equipped with CEMS and PEMS for ammonia, and on a one-hour average for units not equipped with CEMS or PEMS. Proposed new §117.410(d)(3) specifies that the correction of CO emissions to 3.0% O_2, dry basis, does not apply to boilers and process heaters operating at less than 10% maximum load and stack O_2 more than 15%. Proposed new §117.410(d)(4) lists cases where the CO emission specification in proposed new §117.410(d)(1) does not apply, including stationary internal combustion engines subject to proposed new §117.410(a), and incinerators subject to CO limits under 30 TAC §111.121 or §113.2072, or 40 CFR Part 264 or 265, Subpart O, for hazardous waste incinerators.

Proposed new §117.410(e) specifies conditions for compliance flexibility with the NO_x emission specifications of proposed new §117.410. Proposed new §117.410(e)(1) specifies that owners or operators may use the source cap option under proposed new §117.423 or emission reduction credits as specified in proposed new §117.9800, to comply with the NO_x emission specifications of proposed new §117.410. Proposed new §117.410(e)(2) prohibits using proposed new §117.425, concerning alternative case specific specifications, as a method of compliance with the NO_x emission specifications of proposed new §117.410. This prohibition is necessary to ensure that the NO_x reductions anticipated from this proposed rulemaking would be realized. Proposed new §117.410(e)(3) specifies that owners or operators may petition the executive director for an alternative to the CO and ammonia emission specifications according to proposed new §117.425.

Proposed new subsection §117.410(f) establishes the provisions for prohibition of circumvention to ensure the anticipated NO_x reductions modeled for this proposed rulemaking would be realized. The proposed new §117.410(f)(1) establishes that the maximum rated capacity used to determine the applicability of the emissions specifications, initial compliance demonstration, monitoring, testing requirements, and final control plan in §§117.410, 117.435, 117.440, and 117.454 must be the greater of the maximum rated capacity as of December 31, 2000, or the maximum rated capacity authorized by a permit issued under 30 TAC Chapter 116 after December 31, 2000. Proposed new §117.410(f)(2) specifies that a unit's classification for the purposes of Subchapter B, Division 4, is determined by the most specific classification applicable to the unit as of December 31, 2000.

The commission proposes a new §117.410(f)(3), specifying the prohibition of changes to a unit subject to an emission specification in §117.410(b) that results in increased NO_x emissions from a unit not subject to an emission specification of §117.410(b) after December 31, 2000. For example, redirecting one or more fuel or waste streams containing chemical-bound nitrogen to a flare or an incinerator with a maximum rated capacity of less than 40 MMBtu/hr is prohibited. The proposed new §117.410(f)(4) specifies that a source that met the definition of a major source as of December 31, 2000, is always classified as a major source for the purposes of Subchapter B, Division 4. A source that did not meet the definition of major source on December 31, 2000, but which at any time after December 31, 2000, becomes a major source, would from that time forward always be classified as a major source for purposes of Subchapter B, Division 4.

Proposed new §117.410(f)(5) specifies that the availability under §117.410(b)(14) of an alternative 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 §117.410(b)(14) than would otherwise apply to the unit. Proposed new §117.410(f)(6) specifies that prohibition of circumvention of §117.410(f) does not apply to stationary, reciprocating internal combustion engines subject to the IOP emission specifications in §117.410(a) until the compliance date specified in §117.9030(b). These engines are not currently subject to the prohibition of circumvention under existing §117.206, and proposed new §117.410(f)(6) ensures that the provisions of this proposed subsection are not imposed on the owners or operators of these engines until the engines become subject to the new proposed emission specifications in §117.410(b).

Proposed new §117.410(g), relating to operating restrictions, specifies that no person may start or operate any stationary diesel or dual-fuel engine for testing of maintenance between the hours of 6:00 a.m. and noon, except for specific manufacturer's recommended testing requiring a run of over 18 consecutive hours, to verify reliability of emergency equipment (e.g., emergency generators or pumps) immediately after unforeseen repairs, or firewater pumps for emergency response training conducted from April 1 through October 31. For the purposes of this provision, proposed new §117.410(g) also specifies that routine maintenance such as an oil change is not considered to be an unforeseen repair. This provision is identical to a requirement implemented for the Houston-Galveston-Brazoria ozone nonattainment area. The requirement, if adopted, would delay emissions of NO_x from testing of these engines until after noon in order to help limit ozone formation.

Section 117.423, Source Cap

The commission proposes a new §117.423 to provide an optional source cap approach to demonstrating compliance with emission specifications of proposed new §117.410. This proposed source cap option is similar to the source cap allowed under existing §117.223 for major sources in ozone nonattainment areas. Proposed new §117.423(a) specifies that the owner or operator may achieve compliance with the emission specifications of §117.410 by achieving equivalent NO_x emission reductions obtained by compliance with a source cap emission limitation. If an owner or operator elects this option, any equipment category included in the source cap must include all emission units belonging to that category. All emission units not included in the source cap must comply with the requirements of §117.410.

Proposed new §117.423(b) specifies the equations and procedures for determining the source cap allowable NO_x mass emission rate. The equation in proposed new §117.423(b)(1) specifies how to calculate the 30-day rolling average emission cap in pounds per day. This equation is similar to the source cap equation in existing §117.223(b)(1) as it is applicable to the Dallas-Fort Worth ozone nonattainment area. However, the averaging period for determining the historical average daily heat input, variable H_i in the equation, is defined as the 24 consecutive months between January 1, 2000, and December 31, 2001. In addition, the effective date for an applicable permit emission limit for clause (ii) of variable R_i of the equation is December 31, 2000. Proposed new §117.423(b)(2) specifies the equation for calculating the maximum daily cap, in pounds per day, for all units included in the source cap. The proposed equation in proposed new §117.423(b)(2) is identical to the equation for the maximum daily cap in existing §117.223(b)(2).

Proposed new §117.423(b)(3) specifies that each emission unit in the source cap is subject to the requirements of both subsection (b)(1) and (b)(2). In the existing source cap provisions in §117.223, existing §117.223(b)(4) allows the owner or operator to opt in entire classes of exempted units. The commission is not proposing to allow this option under proposed new §117.423 because it would have limited or no benefit to sources in the Dallas-Fort Worth eight-hour ozone nonattainment area due to the relatively few exempted units under the proposed rule.

Proposed new §117.423(b)(4) specifies the equation for calculating the source cap allowable emission rate, in pounds per hour, for stationary internal combustion engines. The equations in proposed new §117.423(b)(4) and (5) for calculation of the source cap allowable emission rate for stationary internal combustion engines and stationary gas turbines, respectively, are similar to the calculations referenced in existing §117.223(b)(5) and (6). Rather than reference a separate division, the applicable equations are proposed in new §117.423(b)(4) and (5). The equations in proposed new §117.423(b)(4) and (5) are identical in content to the original calculations referenced for stationary internal combustion engines and stationary gas turbines under the source cap option in existing §117.223, except that the resultant titles are changed to reflect the source cap option in proposed §117.423 and the section cross-reference in the equation in §117.423(b)(5) references proposed new §117.410(b).

Proposed new §117.423(c) specifies the continuous emissions monitoring and testing requirements for the source included in the source cap. Proposed new §117.423(c)(1)(A) and (B) specifies that for each unit included in the source cap, the owner or operator must comply with the NO_x, CO, O_2 (or carbon dioxide), and fuel monitoring requirements of proposed new §117.440, either using a CEMS or a PEMS. Both §117.423(c)(1)(A) and (B) specify that the CEMS or PEMS, and the fuel flow meters must be used to demonstrate compliance with the source cap. Proposed new §117.423(c)(1)(C) specifies that for units not subject to continuous monitoring requirements, the owner or operator may use the maximum emission rate as measured during testing conducted according to proposed new §117.435(d). Proposed new §117.423(c)(1)(C) also specifies that the emission rates for such units are limited to the maximum emission rates obtained from the testing. Proposed new §117.423(c)(2) specifies that for each unit equipped with a CEMS, the owner or operator shall either use a PEMS or the maximum emission rate measured by testing according to §117.435(d) to provide substitute emissions data when the CEMS is off-line. Methods specified in 40 CFR §75.46 are required for providing substitute data for PEMS.

Proposed new §117.423(d) requires daily records of NO_x emissions and total fuel usage for each unit under the source cap, as well as records of the total NO_x emissions summation and total fuel usage for all units under the source cap. In addition, the records must be maintained in accordance with the requirements of proposed §117.445.

Proposed new §117.423(e) establishes procedures for the reporting of any emission exceedances of the source cap. The proposed procedures are consistent with the reporting requirements under the existing source cap provisions of existing §117.223, including notification of the appropriate regional office within 48 hours, followed by a written report within 21 days, content requirements for the report, and semiannual reporting for monitoring systems. Proposed new §117.423(f) specifies that initial compliance with the source cap shall be demonstrated in accordance with the compliance schedule in §117.9030.

Conditions for including a permanently retired, decommissioned, or rendered inoperable unit in the source cap are specified in proposed new §117.423(g). Proposed paragraph (1) specifies that the shutdown must have occurred after December 31, 2000, and proposed paragraph (2) specifies that the source cap emission limit must be calculated according to subsection (b). Proposed paragraph (3) specifies that the actual heat input must be calculated according to proposed subsection (b)(1). However, if the unit was not in service 24 consecutive months between January 1, 2000, and December 31, 2001, proposed paragraph (3) specifies that the actual heat input must be the heat input used to represent the unit's emissions in the attainment demonstration modeling inventory. Also, the maximum heat input must be the maximum heat input certified by the executive director, allowed or possible (whichever is lower) in a 24-hour period. Proposed paragraph (4) requires the owner or operator to certify the operational level and maximum rated capacity of the unit. Proposed paragraph (5) prohibits emission reductions from shutdowns or curtailments used for netting or offsetting purposes under Chapter 116 from being included in the baseline for establishing the cap.

Proposed new §117.423(h) specifies that owners or operators who choose to use the source cap for compliance with §117.410 must include a plan for compliance in the initial control plan required in proposed new §117.450. In addition, the owner or operator must provide identification of election to use the source cap option, identification of all sources included in the source cap, and the method of calculating the annual heat input for each unit included in the source cap. Proposed new §117.423(i) specifies the procedures for calculating the contributions from each affected unit under the source cap during a startup, shutdown, or emissions event as defined in §117.10.

Finally, the existing rules for major sources of NO_x in the Dallas-Fort Worth ozone nonattainment area provide an additional compliance option using the alternative plant-wide emission specification provisions of existing §117.207. The commission is not proposing to allow the alternative plant-wide emission specifications approach for proposed new Subchapter B, Division 4. A source cap approach provides more flexibility than the alternative plant-wide emission specifications because the owner or operator can choose which source categories to include under the source cap approach. The source cap option in proposed new §117.423 provides sufficient flexibility that providing an additional alternative plant-wide emission specification option would have little or no benefit.

Section 117.425, Alternative Case Specific Specifications

The commission proposes a new §117.425 that provides procedures concerning alternative case specific specifications. Proposed new §117.425(a) specifies that where it can be demonstrated that an affected unit cannot attain the applicable requirements of the CO or ammonia specifications of proposed new §117.410(c), the executive director may approve emission specifications different from the CO or ammonia specifications in §117.410(c) under the proposed guidelines of new §117.425(a)(1) - (3). Proposed new paragraph (1) specifies that the executive director shall consider, on a case-by-case basis, the technological and economic circumstances of the individual unit. Proposed new paragraph (2) requires the executive director to determine whether the alternative emission specifications are the lowest specification the unit is capable of achieving after application of controls to meet the NO_x emission specifications of proposed new §117.410. Proposed new paragraph (3) allows the executive director to consider plant-wide averaging to meet the emission specifications.

Finally, proposed §117.425(b) specifies that any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision, and that the requirements of 30 TAC §50.139 (Motion to Overturn Executive Director's Decision) apply to §117.425. Proposed new subsection (b) also specifies that executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for EPA approval in some cases.

Section 117.430, Operating Requirements

The proposed new §117.430 establishes operating requirements for sources subject to proposed new Subchapter B, Division 4. Proposed new §117.430(a) requires an owner or operator who has chosen to use the source cap option in proposed new §117.423 to comply with the emission specifications to operate affected units in compliance with those limitations.

Proposed new §117.430(b) requires that all units subject to the emission specifications of §117.410(a) or (b) or §117.423 must be operated to minimize NO_x emissions, consistent with the emission control techniques selected, over the units operating or load range during normal operations, and subject to the operating requirements detailed in proposed new §117.430(b)(1) - (7). Proposed paragraph (1) requires boilers, except for wood-fired boilers, to be operated with O_2, CO, or fuel trim. Proposed paragraph (2) requires boilers and process heaters controlled with forced FGR to be operated such that the proportional design rate of FGR is maintained over the operating range. Proposed paragraph (3) requires boilers and process heaters controlled with induced draft FGR to be operated such that FGR over the operating range is not restricted. Proposed new paragraphs (4) and (5) specify that units controlled with steam or water injection, or with post-combustion control must be operated such that the steam or water injection rate, or chemical agent injection rate is maintained to limit NO_x concentrations to less than or equal to concentrations at maximum rated capacity. Proposed paragraph (6) requires an automatic air-fuel ratio (AFR) controller, based on O_2 or CO control, be installed on engines controlled with NSCR, and that the controller maintain the AFR within the range required to meet the applicable emission specification. Finally, proposed paragraph (7) requires that each stationary internal combustion engine be tested for proper operation according to proposed new §117.8140(b), which includes quarterly testing of NO_x and CO emissions. These operating requirements are consistent with the operating requirements specified under existing §117.208 for the Dallas-Fort Worth ozone nonattainment area.

Section 117.435, Initial Demonstration of Compliance

Proposed new §117.435 specifies the requirements for owners or operators of units subject to this division for demonstrating initial compliance with the rule. Proposed new §117.435(a) specifies that the owner or operator of any unit subject to the emission specifications of the division must test the unit. Proposed paragraphs (1) and (2) specify that units must be tested for NO_x, CO, and O_2, and that units that inject urea or ammonia for NO_x control must be tested for ammonia emissions. Proposed paragraph (3) specifies that the testing must be performed in accordance with the compliance schedule in proposed new §117.9030.

Proposed new §117.435(b) specifies that compliance tests required by proposed new §117.435(a) must be performed using the methods referenced in proposed new §117.435(d) or (e) and used for determination of initial compliance with the emission specifications of the division, and must be in the units of the applicable emission specifications and averaging periods. Proposed new §117.435(c) requires that any CEMS or PEMS required by proposed new §117.440 must be installed and operational before conducting the initial demonstration of compliance testing, and specifies the minimum requirements for verifying operational status of the CEMS or PEMS.

Proposed new §117.435(d) references proposed new §117.8000 for the compliance test requirements for units operating without CEMS or PEMS. Proposed new §117.435(e) specifies the requirements of initial compliance testing for units operating with CEMS or PEMS in accordance with §117.440. The initial demonstration of compliance is performed using the CEMS or PEMS after monitor certification. Proposed new paragraphs (1) - (4) specify the procedures for the initial demonstration of compliance using CEMS or PEMS, depending on the unit type, pollutant, applicable averaging time, or whether the unit is included in the optional source cap in proposed new §117.423.

Proposed new §117.435(f) references the information that must be included in compliance stack reports as specified by §117.8010 (Compliance Stack Reports).

Section 117.440, Continuous Demonstration of Compliance

The commission proposes a new §117.440, concerning continuous demonstration of compliance, that specifies the operating, monitoring, and testing required by owners and operators of units subject to the emissions specifications of §117.410 and §117.423. Proposed new §117.410(a) requires the installation, calibration, maintenance, and operation of totalizing fuel flow meters for owners and operators of affected units. Proposed paragraph (1) specifies the units that would be subject to the fuel metering requirements of proposed new §117.440(a). These units include: boilers; process heaters; duct burners used in turbine exhaust ducts; stationary, reciprocating internal combustion engines; stationary gas turbines; lime kilns; brick and ceramic kilns; heat treating furnaces; reheat furnaces; electric arc furnaces used in steel production; lead smelting blast (cupola) and reverberatory furnaces; glass and fiberglass melting furnaces; glass, fiberglass, and mineral wool curing and forming ovens; incinerators (excluding vapor streams resulting from vessel cleaning routed to an incinerator); natural gas-fired ovens and heaters; and natural gas-fired organic solvent, printing ink, clay, brick, ceramic, calcining, and vitrifying dryers.

Proposed new §117.440(a)(2) lists the alternatives to the fuel flow monitoring requirements. Proposed subparagraph (A) allows units operating with NO_x and diluent CEMS to monitor exhaust gas flow rate using 40 CFR Part 60, Appendix B, Performance Specification 6, or 40 CFR Part 75, Appendix A. Proposed subparagraph (B) allows units that vent to a common stack with a NO_x and diluent CEMS to share a single totalizing fuel flow meter. Proposed subparagraph (C) allows diesel engines operating with run time meters to satisfy the fuel monitoring requirements through monthly fuel use records maintained for each engine.

Proposed new §117.440(b) requires owners or operators to install, calibrate, maintain, and operate O_2 monitors for certain units. Proposed new §117.440(b)(1) requires O_2 monitors on units in subparagraphs (A) and (B) that are operated with an annual heat input greater than $2.2(10^{11})$ British thermal units per year. Boilers with a rated heat input greater than or equal to 100 MMBtu/hr are included in proposed paragraph (A). Process heaters with a rated heat input greater than or equal to 100 MMBtu/hr are specified in proposed paragraph (B), with exceptions provided in proposed clauses (i) and (ii). The O_2 monitors required under proposed new §117.440(b) are for process monitoring purposes and proposed new §117.440(b)(2) specifies that the monitors are only required to meet the CEMS requirements of subsection (f) if O_2 is the monitored diluent under subsection (f). If new monitors are required under proposed new §117.440(b), the procedures referenced in §117.440(f) are the appropriate guidance for the monitor location and calibration.

Proposed new §117.440(c) specifies the units for which owners and operators shall install, calibrate, maintain, and operate a CEMS or PEMS to monitor NO_x exhaust. The units listed include: units with a rated heat input greater than or equal to 100 MMBtu/hr that are subject to proposed new §117.410(b); stationary gas turbines with a MW rating greater than or equal to 30 MW operated more than 850 hours per year; units that use a chemical reagent for reduction of NO_x; units that the owner or operator elects to comply with the NO_x emission specifications using a lb/MMBtu limit on a 30-day rolling average; lime kilns; and brick kilns and ceramic kilns. These proposed new monitoring requirements are anticipated to require some owners or operators to install CEMS or PEMS on units that currently do not have CEMS or PEMS. The continuous NO_x monitoring requirements are necessary to ensure compliance with the proposed emission specifications on certain larger units, units that use chemical agents for NO_x control, and units, such as kilns, that are anticipated to have variable emissions. Proposed new §117.440(c)(2) exempts units subject to the NO_x CEMS requirements of 40 CFR Part 75 because the Acid Rain NO_x monitoring requirements would meet or exceed the minimum requirements proposed in §117.440. In addition, proposed new §117.440(c)(3) specifies the methods to be used to provide substitute emissions compliance data during periods when the NO_x monitors are off-line.

New proposed subsection §117.440(d) adds an ammonia monitoring requirement for any unit subject to proposed new §117.410(b) and (c)(2) and references §117.8130 for allowed ammonia monitoring methods. Engines subject to proposed new §117.410(a), the emission specifications from existing §117.206(b)(3), are not currently subject to ammonia monitoring requirements under the existing rule. The commission is not proposing to retroactively impose this requirement on sources subject to §117.206(b)(3). Therefore, proposed new §117.440(d) excludes sources subject to proposed new §117.410(a).

Proposed new §117.440(e) specifies that all owners or operators of unit types listed in §117.440(c)(1) shall monitor CO according to the requirements of proposed new §117.8120. Proposed new §117.440(f) specifies that CEMS used for compliance with this section must be operated within the requirements of proposed new §117.8100(a). Proposed new §117.440(g) specifies that PEMS used to satisfy the monitoring requirements of proposed §117.440 must predict the pollutant emissions in the units of the applicable emission specification and comply with the requirements of proposed new §117.8100(b). The CEMS and PEMS requirements in proposed new §117.8100 are the existing requirements for CEMS and PEMS proposed to be incorporated from existing §117.213.

Proposed new §117.440(h) specifies that the owner or operator of stationary internal combustion engines not equipped with a CEMS or PEMS must comply with the monitoring requirements of §117.8140(a). Under §117.8140(a), engines are required to be testing biennially, or within 15,000 hours of operation, similar to the current requirement under existing §117.213(g).

Proposed new §117.440(i) requires the owner or operator of any stationary gas turbine or stationary internal combustion engine claimed exempt using the exemption in proposed new §117.403(a)(7)(D), (a)(8), or (a)(9) to record the operating time with a non-resettable elapsed run time meter. Proposed new §117.440(j), concerning data used for compliance, specifies that the methods required in proposed new §117.440 must be used to demonstrate compliance with the proposed emission specifications after the initial demonstration of compliance. The provisions of proposed subsection (j) also specify that the executive director may use other commission compliance methods to determine compliance with the emission specifications.

Finally, proposed new §117.440(k) specifies the testing and retesting requirements for units subject to the emission specifications of proposed §117.410. Proposed paragraph (1) specifies that the owner or operator of units that are subject to the emission specifications of §117.410(a) shall test the units as specified in proposed §117.435 in accordance with the schedule specified in proposed new §117.9030(a). Proposed paragraph (2) requires the owner or operator of units subject to the emission specifications of proposed new §117.410(b) to test the units as specified in §117.435 in accordance with the schedule specified in proposed new §117.9030(b). A retesting requirement is specified in proposed paragraph (3) that requires owners or operators to retest any unit subject to the emission specifications of proposed new §117.410(b) after any modification that could be reasonably expected to increase the NO_x emission rate. This proposed retesting provision only applies to units that are not equipped with CEMS or PEMS to monitor NO_x emissions.

Section 117.445, Notification, Recordkeeping, and Reporting Requirements

The commission proposes a new §117.445 that specifies the notification, recordkeeping, and reporting requirements for units subject to the emission specifications of this division. Proposed new §117.445(a), concerning startup and shutdown records, specifies the recordkeeping requirements for units subject to the startup and/or shutdown provisions of §101.222. The record retention and minimum content requirements are specified in proposed new subsection (a). Proposed subsection (a) also specifies that records must be made available for inspection upon request by the executive director, EPA, and any local air pollution control agency having jurisdiction.

Notification requirements are specified in proposed new §117.445(b). Proposed new §117.445(b) requires notification be provided to the appropriate regional office and any local air pollution agency having jurisdiction. The specific notification requirements are listed in proposed new §117.445(b)(1) and (2). Proposed paragraph (1) specifies the notification requirements for units subject to the emission specifications of §117.410(a). Proposed §117.445(b)(1)(A) requires verbal notification of the date of any testing conducted under proposed new §117.435 at least 15 days prior to the date of testing followed by written notification within 15 days after testing is completed. Proposed §117.445(b)(1)(B) requires verbal notification of the date of any CEMS or PEMS relative accuracy test audit (RATA) conducted under §117.440 at least 15 days prior to such date followed by written notification within 15 days after testing is completed. The notification requirements specified in proposed new §117.445(b)(2) are applicable to units subject to the emission specifications in proposed new §117.410(b). Under proposed new §117.445(b)(2), written notice is required at least 15 days in advance of the date of any RATA conducted under proposed §117.440 or test conducted under proposed §117.435. The commission is proposing the single written notification requirement under proposed new §117.445(b)(2) to eliminate the requirement for redundant notifications for units subject to the emissions specification in proposed §117.410(b). However, units subject to proposed §117.410(a) are currently regulated under existing §117.206(b)(3) and subject to the existing notification requirements of existing §117.219(b). The notification requirements in proposed new §117.445(b)(1) are identical to the requirements in existing §117.219(b) to maintain consistency with the current requirements applicable to owners or operators subject to proposed new §117.410(a).

Proposed new §117.445(c), concerning reporting of test results, specifies 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 §117.435 and any CEMS or PEMS RATA conducted under §117.440. Reports must be submitted within 60 days after completion of such testing or evaluation and not later than the compliance schedule specified in proposed new §117.9030.

Proposed new subsection §117.445(d), concerning semiannual reports, requires the owner or operator of a unit required to install a CEMS or PEMS under §117.440 to report in writing to the executive director on a semiannual basis any exceedance of the applicable emission specifications and the associated monitoring system performance. All reports must be postmarked or received by the 30th day following the end of each calendar semiannual period. The information required in the reports is detailed in proposed new §117.445(d)(1) - (5). Proposed paragraph (1) requires the magnitude of excess emissions, computed according to 40 CFR §60.13(h), to be reported, as well as conversion factors used, time period of excess emissions, and unit operating time during the reporting period. Provisions for sources subject to the proposed source cap in proposed new §117.423 are also given. Proposed paragraph (2) lists report requirements for excess emissions during startups, shutdowns, and malfunctions, and proposed paragraph (3) lists report requirements for periods when continuous monitoring systems are inoperative. If no excess emissions or downtime have occurred during the reporting period, proposed paragraph (4) specifies that the report must indicate that no excess emissions or monitoring downtime have occurred. Proposed paragraph (5) provides conditions for summary reports if excess emissions and monitor downtime are limited.

Proposed new §117.445(e) specifies the semiannual reporting requirements for owners and operators of any gas-fired engines. Written reports of excess emissions and the air-fuel ratio monitoring system performance must be submitted to the executive director. All reports must be postmarked or received by the 30th day following the end of each calendar semiannual period. Additional specific information required in the reports is detailed in proposed paragraphs (1) and (2) similar to the current requirements specified in the existing §117.219(e)(1) and (2) for engine semiannual reports.

Proposed new §117.445(f), concerning recordkeeping, specifies requirements for written or electronic records for owners or operators of units subject to the requirements of this division.

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, EPA, or local air pollution control agencies having jurisdiction. Proposed new §117.445(f)(1) specifies that for each unit subject to §117.440(a) the records must include records of annual fuel usage. For each unit using a CEMS or PEMS in accordance with §117.440, proposed new §117.445(f)(2) requires monitoring records of hourly emissions and fuel usage for units complying on a block one-hour average, or daily emissions and fuel usage for units complying with an emission specification enforced on a daily or rolling 30-day average.

For stationary internal combustion engines subject to the proposed emission specifications of the division, proposed new §117.445(f)(3) requires the owner or operator to maintain records of emissions measurements required by proposed §117.430(b)(7) and §117.440(h), as well as catalytic converter, air-fuel ratio controller, or other emissions-related control system maintenance, including the date and nature of corrective actions taken.

Proposed new §117.445(f)(4) specifies owners or operators of units claimed exempt from emission specifications using the exemption of §117.403(a)(7)(D), (a)(8), or (a)(9) must maintain records of monthly hours of operation for exemptions based on hours per year of operation. In addition, for each engine claimed exempt under §117.403(a)(7)(D), 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 dates of the emergency situation.

Proposed new §117.445(f)(5) and (6) requires owners or operators of applicable units to maintain records of ammonia and CO measurements specified in §117.440(d) and (e), respectively. Proposed new §117.445(f)(7) requires owners or operators of units operating with CEMS or PEMS to maintain records of the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance.

Proposed new §117.445(f)(8) requires owners or operators to maintain records of the results of performance testing, including initial demonstration of compliance testing conducted in accordance with proposed new §117.435. Proposed new §117.445(f)(9) specifies owners or operators of each stationary diesel or dual-fuel engine to maintain records of each time the engine is operated for testing and maintenance, including dates of operation, start and end times of operation, identification of the engine, and total hours of operation for each month and for the most recent 12 consecutive months.

Section 117.450, Initial Control Plan Procedures

The commission proposes a new §117.450, concerning initial control plan procedures. Proposed new §117.450(a) requires the owner or operator of any unit at a major source of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area that is subject to §117.410(b) to submit an initial control plan. Proposed new §117.450(a)(1) specifies that the control plan must include a list of all combustion units at the account that are listed in proposed §117.410(b). The list must include for each unit the maximum rated capacity, anticipated annual capacity factor, estimated or measured NO_x emission data in the units associated with the category of equipment from §117.410(b), the method of determination for the NO_x emission data, the facility identification number and emission point number as submitted to the Industrial Emissions Assessment Section of the commission, and the emission point number as listed on the Maximum Allowable Emissions Rate Table of any applicable commission permit.

Proposed new §117.450(a)(2) requires the initial control plan to include the identification of all units with a claimed exemption from the emission specifications in proposed §117.410(b) and the rule basis for the claimed exemption. Proposed new §117.450(a)(3) requires the initial control plan to include the identification of the election to use the source cap emission limit in proposed §117.423 to achieve compliance with this proposed rule and a list of the units to be included in the source cap.

Proposed new §117.450(a)(4) requires the initial control plan to include a list of units to be controlled and the type of control to be applied for each unit, including an anticipated construction schedule. Proposed new §117.450(a)(5) requires the initial control plan to include a list of units requiring operating modifications to comply with §117.430(b) and the type of modification to be applied for each unit, including an anticipated construction schedule. Proposed new §117.450(a)(6) specifies that for units required to install totalizing fuel flow meters in accordance with §117.440(a), the initial control plan must indicate whether the fuel meters are currently in operation, and if so, whether they have been installed as a result of the requirements of this proposed rule.

Proposed new §117.450(a)(7) specifies that for units required to install CEMS or PEMS in accordance with §117.440, the initial control plan must indicate whether the devices are currently in operation, and if so, whether they have been installed as a result of the requirements of this proposed rule.

Proposed new §117.450(b) specifies the initial control plan must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Chief Engineer's Office by the applicable date specified for initial control plans in proposed new §117.9030(b).

Finally, proposed new §117.450(c) specifies that for units located in Dallas, Denton, Collin, and Tarrant Counties, subject to proposed new §117.210, the owner or operator may elect to submit the most recent revision of the final control plan required by proposed new §117.254 in lieu of the initial control plan required by proposed subsection (a).

Section 117.454, Final Control Plan Procedures for Attainment Demonstration Emission Specifications

The commission proposes a new §117.454 that requires the owner or operator of any unit subject to proposed new §117.410(b) at a major source of NO_x to submit a final control report to show compliance with the requirements of proposed §117.410.

Proposed new §117.454(a)(1) - (5) specify the content requirements of the report. The final control report must identify which sections are used to demonstrate compliance. In addition, the report must include: the method of NO_x control for each unit; the emissions measured by testing required in proposed §117.435; the submittal date, and whether sent to the central or the regional office (or both), of any compliance stack test report or RATA report required by §117.435 not being submitted concurrently with the final compliance report; and the specific rule citation for any unit with a claimed exemption from the emission specifications of proposed §117.410.

Proposed new §117.454(b)(1) - (3) specifies that for sources complying with proposed §117.423, in addition to the requirements of proposed subsection (a), the owner or operator shall submit: the calculations used to calculate the 30-day average and maximum daily source cap allowable emission rates; the average daily heat input, H_i, specified in proposed §117.423(b)(1); the maximum daily heat input, H_{mi}, specified in proposed §117.423(b)(1); the method of monitoring emissions; the method of providing substitute emissions data when the NO_x monitoring system is not providing valid data; and an explanation of the basis of the values of H_i and H_{mi}.

Proposed new §117.454(c) specifies the report must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Chief Engineer's Office by the applicable date specified for final control plans in proposed §117.9030(b). The plan must be updated with any emission compliance measurements submitted for units using CEMS or PEMS and complying with the source cap rolling 30-day average emission limit, according to the applicable schedule given in §117.9030.

Section 117.456, Revision of Final Control Plan

The commission proposes a new §117.456, concerning revision of final control plan, to specify the conditions under which a revised final control plan may be submitted by the owner or operator, along with any required permit applications. The section specifies that such a plan must adhere to the requirements and the final compliance dates of the division, and that for sources complying with proposed §117.410, replacement new units may be included in the control plan. Also, for sources complying with proposed §117.423, 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. Finally, proposed new §117.456 specifies that the revision of the final control plan is subject to the review and approval of the executive director.

SUBCHAPTER C, COMBUSTION CONTROL AT MAJOR UTILITY ELECTRIC GENERATION SOURCES IN OZONE NONATTAINMENT AREAS

The commission proposes a new Chapter 117, Subchapter C, entitled Combustion Control at Major Utility Electric Generation Sources in Ozone Nonattainment Areas, that incorporates the rule language from existing Chapter 117, Subchapter B, Combustion at Major Sources, Division 1, Utility Electric Generation in Ozone Nonattainment Areas. The proposed new Subchapter C is structured based on regional nonattainment areas. Each proposed new division applies only to a specific ozone nonattainment area. Rule language from existing Subchapter B, Division 1 that is not applicable for the specific region is not proposed to be included in the new division for that specific region. Unless otherwise specified in this preamble, such exclusions of rule language not applicable to the specific region are considered non-substantive changes and are not specifically discussed in the preamble.

In addition, the commission proposes a new Subchapter C, Division 4, entitled Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources, that includes new rule language and requirements associated with major utility electric generation sources in the Dallas-Fort Worth eight-hour ozone nonattainment area. The new Subchapter C, Division 4 is proposed as a part of the commission's eight-hour ozone attainment demonstration for the Dallas-Fort Worth eight-hour ozone nonattainment area.

DIVISION 1, BEAUMONT-PORT ARTHUR OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

The commission proposes a new Chapter 117, Subchapter C, Division 1, entitled Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources, that incorporates the provisions in the existing Chapter 117, Subchapter B, Division 1, applicable to utility electric generation sources in the Beaumont-Port Arthur ozone nonattainment area.

Section 117.1000, Applicability

The commission proposes a new §117.1000 that incorporates the applicability rule language in existing §117.101 applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.1000(a) incorporates the rule language in the existing §117.101(a) and (a)(1) - (4). The list of applicable units in existing §117.101(a)(1) - (4), including utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in turbine exhaust ducts, is incorporated into the proposed new §117.1000(a). Proposed new §117.1000(a)(1) and (2) incorporate the language regarding owners or operators of the applicable units. Proposed new §117.1000(a)(1) incorporates the rule language from existing §117.101(a) concerning the applicability related to units owned or operated by a municipality or a PUC-regulated utility. In addition, the commission proposes a new §117.1000(a)(2) concerning the applicability of the division to electric power generating systems owned or operated by an electric cooperative, independent power producer, municipality, river authority, or public utility. This proposed change is intended to clarify the applicability of the rule and does not expand the applicability of the rule. Finally, the commission also proposes a new §117.1000(b) that incorporates the rule language in existing §117.101(b).

Section 117.1003, Exemptions

The commission proposes a new §117.1003 that incorporates the exemptions in the existing §117.103 applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.1003(a) - (c) incorporate the exemptions in the existing §117.103(a) - (c). In addition, for proposed new §117.1003(c)(1), the commission proposes to revise the existing language in §117.103(c)(1) to expand the provisions relating to emergency fuel oil firing exemptions to emergency operating conditions declared by the Southeastern Electric Reliability Council, and to remove reference to the Southwest Power Pool. This proposed change is necessary because the Southeastern Electric Reliability Council area overlaps the Beaumont-Port Arthur ozone nonattainment area. The Southwest Power Pool area does not apply to the Beaumont-Port Arthur ozone nonattainment area.

Section 117.1005, Emission Specifications for Reasonably Available Control Technology (RACT)

The commission proposes a new §117.1005 that incorporates the rule language in the existing §117.105, relating to emission specifications for RACT, applicable to the Beaumont-Port Arthur ozone nonattainment area. The commission proposes a new §117.1005(a) - (l) that incorporates the rule language in the existing §117.105(a) - (l).

The commission proposes a new equation in §117.1005(d) that incorporates the existing equation for calculating the rolling 24-hour heat input weighted average emission specification in the existing §117.105(d). The proposed new equation in §117.1005(d) presents the equation in a format consistent with other figures in Chapter 117 and provides a written description of all the terms used in the equation. In addition, for proposed new §117.1005(e), the commission proposes using auxiliary steam boilers as opposed to auxiliary boilers used in the existing language to be consistent with the definition in §117.10. For proposed new §117.1005(i), the commission proposes to change the word "ten" to the numeral "10" regarding the MW rating for stationary gas turbines subject to the CO emission specification in proposed new §117.1005(i). Finally, proposed new §117.1005(l) incorporates the rule language from existing §117.105(l) and (l)(1).

Section 117.1010, Emission Specifications for Attainment Demonstration

The commission proposes a new §117.1010 that incorporates the rule language in the existing §117.106, relating to emission specifications for attainment demonstrations, applicable to the Beaumont-Port Arthur ozone nonattainment area.

The commission proposes a new §117.1010(a), relating to NO_x emission specifications, that incorporates the rule language and emission specifications in the existing §117.106(a). Proposed new §117.1010(b) incorporates the rule language concerning related emissions in the existing §117.106(d). In addition, for proposed new §117.1010(b)(2), the commission proposes to change the emissions specification for ammonia from the word "ten" to the numeral "10." As previously discussed in this preamble, this change is necessary to ensure consistent enforcement of the emission specification. Proposed new §117.1010(c), relating to compliance flexibility, incorporates the rule language in the existing §117.106(e) and (e)(1) - (3).

Section 117.1015, Alternative System-Wide Emission Specifications

The commission proposes a new §117.1015 that incorporates the rule language in the existing §117.107, relating to alternative system-wide emission specifications, applicable to the Beaumont-Port Arthur ozone nonattainment area. The commission proposes a new §117.1015(a) - (d) that incorporates the rule language in the existing §117.107(a) - (d). In addition, for proposed new §117.1015, the commission is proposing to revise language in existing §117.107 referencing system-wide emission limit or system-wide emission limitation to specify system-wide emission specification. These changes are proposed to provide consistency and clarity in proposed new §117.1015 and to be consistent with the section title and the proposed change to the definition of system-wide emission limit in §117.10 discussed previously in this preamble.

Proposed new §117.1015(d) incorporates the rule language from existing §117.107(d). In addition, existing §117.107(d)(1) and (2) include required calculations written in paragraph form rather than in equation form. The commission is proposing to reformat the calculations in a mathematical formula rather than the paragraph form to present the equations in a format consistent with other equations in Chapter 117 and provide a written description of all the terms used in the equation. The proposed new equations are identical in content to the existing required calculations in paragraph form. The proposed new equation in §117.1015(d)(1) incorporates the calculation for allowable system-wide NO_x emission specification for each affected utility boiler in the existing §117.107(d)(1). The proposed new equations in §117.1015(d)(2) incorporate the calculation for the allowable NO_x emission rate for each affected stationary gas turbine in the existing §117.107(d)(2) as well as the existing equation for the in-stack NO_x concentration term in the existing §117.107(d)(2).

Section 117.1020, System Cap

The commission proposes a new §117.1020 that incorporates the rule language in the existing §117.108, relating to system cap, applicable to the Beaumont-Port Arthur ozone nonattainment area. The commission proposes a new §117.1020(a) - (k) that incorporates the rule language in the existing §117.108(a) - (k). In addition, the commission proposes new equations in §117.1020(c) that incorporate the equations in existing §117.108(c) and present the equations in a format consistent with other equations in Chapter 117. The proposed new equations in §117.1020(c) include only the information applicable to the Beaumont-Port Arthur ozone nonattainment area. The proposed new equation in §117.1020(c)(1) incorporates the equation for the rolling 30-day average emission cap in the existing §117.108(c)(1). The proposed new equation in §117.1020(c)(2) incorporates the equation for the maximum daily emission cap in the existing §117.108(c)(2).

The commission proposes a new §117.1020(k) that incorporates the requirements of the existing §117.108(k). The new §117.1020(k) changes source cap to system cap to be consistent with the section. Also, for proposed new §117.1020(k), the commission proposes to replace upset period with the language "emissions event, as defined in §101.1 of this title (relating to Definitions) . . .." This proposed change is necessary to update the rule to current terminology used by the commission.

The commission proposes a new §117.1020(l) relating to the use of emissions credits, that incorporates the rule language from existing §117.109, System Cap Flexibility. Proposed new §117.1020(m) relating to the sale and transfer of an electric generating system, incorporates the rule language from existing §117.110, Change of Ownership - System Cap.

Section 117.1025, Alternative Case Specific Specifications

The commission proposes a new §117.1025 that incorporates the rule language in the existing §117.121, relating to alternative case specific specifications, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.1025(a) and (b) incorporate the rule language in the existing §117.121(a) and (b). In addition, the proposed new §117.1025(a) omits the provision in the existing §117.121(a)(4) because the Engineering Services Team no longer exists within the TCEQ.

Section 117.1035, Initial Demonstration of Compliance

The commission proposes a new §117.1035 that incorporates the rule language in the existing §117.111, relating to initial demonstration of compliance, applicable to the Beaumont-Port Arthur ozone nonattainment area.

Section 117.1040, Continuous Demonstration of Compliance

The commission proposes a new §117.1040 that incorporates the rule language in the existing §117.113, relating to continuous demonstration of compliance, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.1040(a) incorporates the rule language in the existing §117.113(a), relating to NO_x monitoring. Proposed new §117.1040(b) incorporates the CO monitoring requirements from existing §117.113(b). The specific requirements and methods in the existing §117.113(b) appear in the proposed new §117.8120, relating to CO monitoring, and subsequently have been omitted from proposed new §117.1040(b) and replaced with a reference to the proposed new §117.8120. Similarly, the requirements for CEMS in the existing §117.113(c)(1) and (2) appear in the proposed new §117.8110(a), relating to emission monitoring system requirements for utility electric generation sources. Therefore, the proposed new §117.1040(c) omits the specific requirements of existing §117.113(c)(1) and (2) and references to the proposed new §117.8110(a).

Proposed new §117.1040(d) incorporates the rule language from existing §117.113(d), concerning acid rain peaking units. Proposed new §117.1040(e) incorporates the rule language from existing §117.113(e), concerning auxiliary boilers. In addition, for proposed new §117.1040(e), the commission proposes to revise auxiliary boiler to auxiliary steam boiler to be consistent with the definition in §117.10.

The commission proposes a new §117.1040(f) that incorporates the requirements for PEMS from existing §117.113(f). Proposed new §117.1040(f)(1) incorporates the rule language from existing §117.113(f)(1). The requirements in the existing §117.113(f)(2) - (4) appear in the proposed new §117.8110(b), relating to emission monitoring system requirements for utility electric generation sources, and subsequently have been omitted from the proposed new §117.1040(f) and replaced with a reference to §117.8110(b) in proposed new §117.1040(f)(2).

Proposed new §117.1040(g) - (j) incorporate the rule language applicable to the Beaumont-Port Arthur ozone nonattainment area from existing §117.113(g) - (j), respectively. Proposed new §117.1040(k) incorporates the rule language from existing §117.113(k) and (k)(1), and proposed new §117.1040(l) incorporates the rule language from existing §117.113(l).

Section 117.1045, Notification, Recordkeeping, and Reporting Requirements

The commission proposes a new §117.1045 that incorporates the requirements in the existing §117.119, relating to notification, recordkeeping, and reporting requirements, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.1045(a) - (e) incorporate the rule language from existing §117.119(a) - (e). In addition, for proposed new §117.1045(a), the commission proposes to replace the language "the startup and/or shutdown exemptions allowed under §101.222" with "the startup and/or shutdown provisions of §101.222 . . .." The reference to exemptions is not applicable to §101.222 and the proposed change is necessary to clarify proposed new §117.1045(a). The commission is soliciting comments on this specific change to the language in existing §117.119(a). The commission is also soliciting comments on whether the reference to §101.222 should be removed.

Section 117.1052, Final Control Plan Procedures for Reasonably Available Control Technology

The commission proposes a new §117.1052 that incorporates the rule language in the existing §117.115, relating to final control plan procedures for RACT, applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.1052(a), (b), and (c) incorporate the rule language from existing §117.115(a), (b) and (d), respectively. In addition, the commission proposes to revise the section title reference in proposed new §117.1052(a)(2)(B) to reference the correct title "Alternative System-Wide Emission Specifications." Also, the commission proposes to omit the existing §117.115(c), relating to electronic submission and formatting requirements for the control plan, from the proposed new §117.1052. Existing §117.115 and proposed new §117.1052 specify the content requirements for the control plan. Therefore, a mandatory format for the control plan information is not necessary.

Section 117.1054, Final Control Plan Procedures for Attainment Demonstration Emission Specifications

The commission proposes a new §117.1054 that incorporates the rule language in the existing §117.116, relating to final control plan procedures for attainment demonstration emission specifications, applicable to the Beaumont-Port Arthur ozone nonattainment area.

Section 117.1056, Revision of Final Control Plan

The commission proposes a new §117.1056 that incorporates the rule language in the existing §117.117, relating to revision of final control plan, applicable to the Beaumont-Port Arthur ozone nonattainment area.

DIVISION 2, DALLAS-FORT WORTH OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

The commission proposes a new Chapter 117, Subchapter C, Division 2, entitled Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources, that incorporates the rule language in the existing Chapter 117, Subchapter B, Division 1 applicable to utility electric generation sources in the Dallas-Fort Worth ozone nonattainment area.

Section 117.1100, Applicability

The commission proposes a new §117.1100 that incorporates the applicability rule language in the existing §117.101 applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.1100(a) incorporates the rule language in the existing §117.101(a) and (a)(1) - (4). The list of applicable units in existing §117.101(a)(1) - (4), including utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in turbine exhaust ducts, is incorporated into the proposed new §117.1100(a). Proposed new §117.1100(a)(1) and (2) incorporate the language regarding owners or operators of the applicable units. Proposed new §117.1100(a)(1) incorporates the rule language from existing §117.101(a) concerning the applicability related to units owned or operated by a municipality or a PUC-regulated utility. In addition, the commission proposes a new §117.1100(a)(2) concerning the applicability of the division to electric power generating systems owned or operated by an electric cooperative, independent power producer, municipality, river authority, or public utility. As previously indicated in this preamble, this proposed change is intended to clarify the applicability of the rule and does not expand the applicability of the rule. The commission proposes a new §117.1100(b) that incorporates the rule language in existing §117.101(b).

Finally, the commission proposes a new §117.1100(c) that specifies the provisions of the proposed new Subchapter C, Division 2 no longer apply to any electric generating facility in Collin, Dallas, Denton, and Tarrant Counties that is subject to the emission specifications in proposed new §117.1310, after the appropriate date in the proposed new §117.9130, relating to the compliance schedule for Dallas-Fort Worth eight-hour ozone nonattainment area utility electric generation sources. The emission specifications in proposed new §117.1310 and all other associated requirements in the proposed new Subchapter C, Division 4, entitled Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources, discussed later in this preamble, would supersede the requirements of Subchapter C, Division 2 after the compliance date for the proposed new rules in Subchapter C, Division 4. Therefore, the commission proposes new §117.1100(c) to avoid overlapping requirements from the two separate divisions.

Section 117.1103, Exemptions

The commission proposes a new §117.1103 that incorporates the exemptions in the existing §117.103, relating to exemptions for utility electric generation sources in ozone nonattainment areas, applicable to the Dallas-Fort Worth ozone nonattainment area. The commission proposes a new §117.1103(a) - (c) that incorporate the rule language in the existing §117.103(a) - (c). In addition, for proposed new §117.1103(c)(1), relating to emergency fuel oil firing exemptions, the commission proposes to omit reference to the Southwest Power Pool for the emergency fuel oil firing exemption provisions because the Southwest Power Pool area does not apply to the Dallas-Fort Worth ozone nonattainment area.

Section 117.1105, Emission Specifications for Reasonably Available Control Technology (RACT)

The commission proposes a new §117.1105 that incorporates the rule language in the existing §117.105, relating to emission specifications for RACT, applicable to the Dallas-Fort Worth ozone nonattainment area. The commission proposes a new §117.1105(a) - (l) that incorporates the rule language in the existing §117.105(a) - (l).

The commission proposes a new equation in §117.1105(d) that incorporates the existing equation for calculating the rolling 24-hour heat input weighted average emission specification in the existing §117.105(d). The proposed new equation in §117.1105(d) presents the equation in a format consistent with other figures in Chapter 117 and provides a written description of all the terms used in the equation. In addition, for proposed new §117.1105(e), the commission proposes using auxiliary steam boilers as opposed to auxiliary boilers used in the existing language to be consistent with the definition in §117.10. For proposed new §117.1105(i), the commission proposes to change the word "ten" to the numeral "10" regarding the MW rating for stationary gas turbines subject to the CO emission specification in proposed new §117.1105(i). Finally, proposed new §117.1105(l) incorporates the rule language from existing §117.105(l) and (l)(2).

Section 117.1110, Emission Specifications for Attainment Demonstration

The commission proposes a new §117.1110 relating to emission specifications for attainment demonstration, that incorporates the rule language in the existing §117.106, relating to emission specifications for attainment demonstrations, applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.1110(a), relating to NO_x emission specifications, incorporates the emission specifications and rule language in the existing §117.106(b). In addition, for proposed new §117.1110(a)(1) and (2), the commission proposes to change large DFW system and small DFW system in existing §117.106(b) to large utility system and small utility system to be consistent with the proposed changes to the definitions in proposed new §117.10(24) and (44). Proposed new §117.1110(a)(1) incorporates the existing emission specification for boilers that are part of a large utility system, as defined in the proposed new §117.10(24), and proposed new §117.1110(a)(2) incorporates the existing emission specification for boilers that are part of a small utility system, as defined in proposed new §117.10(44). Both proposed new §117.1110(a)(1) and (2) incorporate the provisions from existing §117.106(b) concerning use of system cap and use of emission credits for compliance. In addition, proposed new §117.1110(a)(2) incorporates the provision in existing §117.106(b) that specifies that the annual heat input exemption is not applicable to a small utility system. The reference in existing §117.106(b) also incorrectly references §117.103(2) for this heat input exemption. Therefore, for proposed new §117.1110(a)(2), the commission proposes to revise the reference to cite proposed new §117.1103(a)(2), the correct reference for the annual heat input exemption.

The commission proposes a new §117.1110(b) that incorporates the rule language concerning related emissions in the existing §117.106(d). In addition, for proposed new §117.1110(b)(2), the commission proposes to change the emissions specification for ammonia from the word "ten" to the numeral "10." As previously discussed in this preamble, this change is necessary to ensure consistent enforcement of the emission specification. Finally, proposed new §117.1110(c), relating to compliance flexibility, that incorporates the rule language in the existing §117.106(e) and (e)(1) - (3).

Section 117.1115, Alternative System-Wide Emission Specifications

The commission proposes a new §117.1115 that incorporates the specifications in the existing §117.107, relating to alternative system-wide emission specifications, applicable to the Dallas-Fort Worth ozone nonattainment area.

The commission proposes a new §117.1115(a) - (d) that incorporates the rule language in the existing §117.107(a) - (d). In addition, for proposed new §117.1115, the commission is proposing to revise language in existing §117.107 referencing system-wide emission limit or system-wide emission limitation to specify system-wide emission specification. These changes are proposed to provide consistency and clarity in proposed new §117.1115 and to be consistent with the section title and the proposed change to the definition of system-wide emission limit in §117.10 discussed previously in this preamble.

Proposed new §117.1115(d) incorporates the rule language from existing §117.107(d). In addition, existing §117.107(d)(1) and (2) include required calculations written in paragraph form rather than in equation form. The commission is proposing to reformat the calculations in a mathematical formula rather than the paragraph form to present the equations in a format consistent with other equations in Chapter 117 and provide a written description of all the terms used in the equation. The proposed new equations are identical in content to the existing required calculations in paragraph form. The proposed new equation in §117.1115(d)(1) incorporates the calculation for allowable system-wide NO_x emission specification for each affected utility boiler in the existing §117.107(d)(1). The proposed new equations in §117.1115(d)(2) incorporate the calculation for the allowable NO_x emission rate for each affected stationary gas turbine in the existing §117.107(d)(2), as well as the existing equation for the in-stack NO_x concentration term in the existing §117.107(d)(2).

Section 117.1120, System Cap

The commission proposes a new §117.1120 that incorporates the requirements in the existing §117.108, relating to system cap, applicable to the Dallas-Fort Worth ozone nonattainment area.

The commission proposes a new §117.1120(a) - (k) that incorporates the rule language in the existing §117.108(a) - (k). In addition, the commission proposes new equations in §117.1120(c) that incorporate the equations in existing

§117.108(c) and present the equations in a format consistent with other equations in Chapter 117. The proposed new equations in §117.1120(c) include only the information applicable to the Dallas-Fort Worth ozone nonattainment area. The proposed new equation in §117.1120(c)(1) incorporates the equation for the rolling 30-day average emission cap in the existing §117.108(c)(1). The proposed new equation in §117.1120(c)(2) incorporates the equation for the maximum daily emission cap in the existing §117.108(c)(2).

The commission proposes a new §117.1120(k) that incorporates the requirements of the existing §117.108(k). The new §117.1120(k) changes source cap to system cap to be consistent with the section. Also, for proposed new §117.1120(k), the commission proposes to replace upset period with the language "emissions events, as defined in §101.1 of this title (relating to Definitions)." This proposed change is necessary to update the rule to current terminology used by the commission.

The commission proposes a new §117.1120(l) relating to the use of emissions credits, that incorporates the rule language from existing §117.109, concerning system cap flexibility. Proposed new §117.1120(m), relating to the sale and transfer of an electric generating system, incorporates the rule language from existing §117.110, concerning change of ownership.

Section 117.1125, Alternative Case Specific Specifications

The commission proposes a new §117.1125 that incorporates the specifications in the existing §117.121, relating to alternative case specific specifications, applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.1125(a) and (b) incorporate the rule language in the existing §117.121(a) and (b). In addition, the proposed new §117.1125(a) omits the provision in the existing §117.121(a)(4) because the Engineering Services Team no longer exists within the TCEQ.

Section 117.1135, Initial Demonstration of Compliance

The commission proposes a new §117.1135 that incorporates the specifications in the existing §117.111, relating to initial demonstration of compliance, applicable to the Dallas-Fort Worth ozone nonattainment area.

Section 117.1140, Continuous Demonstration of Compliance

The commission proposes a new §117.1140 that incorporates the rule language in existing §117.113, relating to continuous demonstration of compliance, applicable to the Dallas-Fort Worth ozone nonattainment area.

Proposed new §117.1140(a) incorporates the rule language in the existing §117.113(a), relating to NO_x monitoring. Proposed new §117.1140(b) incorporates the CO monitoring requirements from existing §117.113(b). The specific requirements and methods in the existing §117.113(b) appear in proposed new §117.8120, relating to CO monitoring, and subsequently have been omitted from proposed new §117.1140(b) and replaced with a reference to the proposed new §117.8120. Similarly, the requirements for CEMS in the existing §117.113(c)(1) and (2) appear in the proposed new §117.8110(a), relating to emission monitoring system requirements for utility electric generation sources. Therefore, the proposed new §117.1140(c) omits the specific requirements of existing §117.113(c)(1) and (2) and references the proposed new §117.8110(a).

Proposed new §117.1140(d) incorporates the rule language from existing §117.113(d), concerning acid rain peaking units. Proposed new §117.1140(e) incorporates the rule language from existing §117.113(e), concerning auxiliary boilers. In addition, for proposed new §117.1140(e), the commission proposes to revise auxiliary boiler to auxiliary steam boiler to be consistent with the definition in §117.10.

The commission proposes a new §117.1140(f) that incorporates the requirements for PEMS from existing §117.113(f). Proposed new §117.1140(f)(1) incorporates the rule language from existing §117.113(f)(1). The requirements in the existing §117.113(f)(2) - (4) appear in the proposed new §117.8110(b), relating to emission monitoring system requirements for utility electric generation sources, and subsequently have been omitted from the proposed new §117.1140(f) and replaced with a reference to §117.8110(b) in proposed new §117.1140(f)(2).

Proposed new §117.1140(g) - (j) incorporate the rule language applicable to the Dallas-Fort Worth ozone nonattainment area from existing §117.113(g) - (j), respectively. Proposed new §117.1140(k) incorporates the rule language from existing §117.113(k) and (k)(1), and proposed new §117.1140(l) incorporates the rule language from existing §117.113(l).

Section 117.1145, Notification, Recordkeeping, and Reporting Requirements

The commission proposes a new §117.1145 that incorporates the rule language in the existing §117.119, relating to notification, recordkeeping, and reporting requirements, applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.1145(a) - (e) incorporate the rule language from existing §117.119(a) - (e). In addition, for proposed new §117.1145(a), the commission proposes to replace the language "the startup and/or shutdown exemptions allowed under §101.222" with "the startup and/or shutdown provisions of §101.222 . . . ." The reference to exemptions is not applicable to §101.222 and the proposed change is necessary to clarify proposed new §117.1145(a). The commission is soliciting comments on this specific change to the language in existing §117.119(a). The commission is also soliciting comments on whether the reference to §101.222 should be removed.

Section 117.1152, Final Control Plan Procedures for Reasonably Available Control Technology

The commission proposes a new §117.1152 that incorporates the requirements in the existing §117.115, relating to final control plan procedures for RACT, applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.1152(a), (b), and (c) incorporate the rule language from existing §117.115(a), (b) and (d), respectively. In addition, the commission proposes to revise the section title reference in proposed new §117.1152(a)(2)(B) to reference the correct title "Alternative System-Wide Emission Specifications." Also, the commission proposes to omit the existing §117.115(c), relating to electronic submission and formatting requirements for the control plan, from the proposed new §117.1152. Existing §117.115 and proposed new §117.1152 specify the content requirements for the control plan. Therefore, a mandatory format for the control plan information is not necessary.

Section 117.1154, Final Control Plan Procedures for Attainment Demonstration Emission Specifications

The commission proposes a new §117.1154 that incorporates the rule language in existing §117.116, relating to final control plan procedures for attainment demonstration emission specifications, applicable to the Dallas-Fort Worth ozone nonattainment area.

Section 117.1156, Revision of Final Control Plan

The commission proposes a new §117.1156 that incorporates the requirements in the existing §117.117, relating to revision of final control plan, applicable to the Dallas-Fort Worth ozone nonattainment area.

DIVISION 3, HOUSTON-GALVESTON-BRAZORIA OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

The commission proposes a new Chapter 117, Subchapter C, Division 3, entitled Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources, that incorporates the provisions in existing Chapter 117, Subchapter B, Division 1 applicable to utility electric generation sources in the Houston-Galveston-Brazoria ozone nonattainment area.

Section 117.1200, Applicability

The commission proposes a new §117.1200, that incorporates the provisions in the existing §117.101, relating to applicability, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.1200(a) incorporates the rule language in the existing §117.101(a) and (a)(1) - (4). The list of applicable units in existing §117.101(a)(1) - (4), including utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in turbine exhaust ducts, is incorporated into the proposed new §117.1200(a). Proposed new §117.1200(a)(1) and (2) incorporate the language regarding owners or operators of the applicable units. Proposed new §117.1200(a)(1) incorporates the rule language from existing §117.101(a) concerning the applicability related to units owned or operated by a municipality or a PUC-regulated utility. In addition, the commission proposes a new §117.1200(a)(2) concerning the applicability of the division to electric power generating systems owned or operated by an electric cooperative, independent power producer, municipality, river authority, or public utility. As previously indicated in this preamble, this proposed change is intended to clarify the applicability of the rule and does not expand the applicability of the rule. The commission proposes a new §117.1200(b) that incorporates the rule language in existing §117.101(b).

Section 117.1203, Exemptions

The commission proposes a new §117.1203 that incorporates the exemptions in the existing §117.103, relating to exemptions for utility electric generation sources in ozone nonattainment areas, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.1203(a) - (c) incorporate the exemptions in the existing §117.103(a) - (c). In addition, for proposed new §117.1203(c)(1), the commission proposes to revise the existing language in §117.103(c)(1) to expand the provisions relating to emergency fuel oil firing exemptions to emergency operating conditions declared by the Southeastern Electric Reliability Council, and to remove reference to the Southwest Power Pool. This proposed change is necessary because the Southeastern Electric Reliability Council area does overlap the Houston-Galveston-Brazoria ozone nonattainment area. The Southwest Power Pool area does not apply to the Houston-Galveston-Brazoria ozone nonattainment area.

Section 117.1205, Emission Specifications for Reasonably Available Control Technology (RACT)

The commission proposes a new §117.1205 that incorporates the specifications in the existing §117.105, relating to emission specifications for RACT, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. The commission proposes a new §117.1205(a) - (l) that incorporates the rule language in the existing §117.105(a) - (l).

The commission proposes a new equation in §117.1205(d) that incorporates the existing equation for calculating the rolling 24-hour heat input weighted average emission specification in the existing §117.105(d). The proposed new equation in §117.1205(d) presents the equation in a format consistent with other figures in Chapter 117 and provides a written description of all the terms used in the equation. In addition, for proposed new §117.1205(e), the commission proposes using auxiliary steam boilers as opposed to auxiliary boilers used in the existing language to be consistent with the definition in §117.10. For proposed new §117.1205(i), the commission proposes to change the word "ten" to the numeral "10" regarding the MW rating for stationary gas turbines subject to the CO emission specification in proposed new §117.1205(i). Finally, proposed new §117.1205(l) incorporates the rule language from existing §117.105(l) and (l)(3).

Section 117.1210, Emission Specifications for Attainment Demonstration

The commission proposes a new §117.1210 that incorporates the rule language in the existing §117.106, relating to emission specifications for attainment demonstrations, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed a new §117.1210(a) incorporates the specifications in the existing §117.106(c). The catchline is also proposed to be changed to "Emission specifications for the Mass Emission Cap and Trade Program" to more accurately reflect the purpose of the emission specifications in combination with the Mass Emission Cap and Trade Program in Chapter 101, Subchapter H, Division 3. Proposed new §117.1210(b) incorporates the rule language concerning related emissions in the existing §117.106(d). In addition, for proposed new §117.1210(b)(2), the commission proposes to change the emissions specification for ammonia from the word "ten" to the numeral "10." Consistent with EPA guidance, the commission normally enforces emission test and monitoring results to the same significant figures as the emission specifications. Using the numeral "10" for the ammonia emission specification would ensure consistent enforcement of the emission specification.

Finally, the commission proposes a new §117.1210(c) and (c)(1) - (4), relating to compliance flexibility, that incorporates the rule language in the existing §117.106(e) and (e)(2) - (4).

Section 117.1215, Alternative System-Wide Emission Specifications

The commission proposes a new §117.1215 that incorporates the rule language in the existing §117.107, relating to alternative system-wide emission specifications, applicable to the Houston-Galveston-Brazoria ozone nonattainment area.

The commission proposes a new §117.1215(a) - (e) that incorporates the rule language in the existing §117.107(a) - (e). In addition, for proposed new §117.1215, the commission is proposing to revise language in existing §117.107 referencing system-wide emission limit or system-wide emission limitation to specify system-wide emission specification. These changes are proposed to provide consistency and clarity in proposed new §117.1215 and to be consistent with the section title and the proposed change to the definition of system-wide emission limit in §117.10 discussed previously in this preamble.

Proposed new §117.1215(d) incorporates the rule language from existing §117.107(d). In addition, existing §117.107(d)(1) and (2) include required calculations written in paragraph form rather than in equation form. The commission is proposing to reformat the calculations in a mathematical formula rather than the paragraph form to present the equations in a format consistent with other equations in Chapter 117 and provide a written description of all the terms used in the equation. The proposed new equations are identical in content to the existing required calculations in paragraph form. The proposed new equation in §117.1215(d)(1) incorporates the calculation for allowable system-wide NO_x emission specification for each affected utility boiler in the existing §117.107(d)(1). The proposed new equations in §117.1215(d)(2) incorporate the calculation for the allowable NO_x emission rate for each affected stationary gas turbine in the existing §117.107(d)(2) as well as the existing equation for the in-stack NO_x concentration term in the existing §117.107(d)(2).

The commission proposes a new §117.1215(e) that incorporates the rule language in the existing §117.107(e). In addition, for proposed new §117.1215(e), the commission proposes using system-wide as opposed to plant-wide that is used in the existing language to be consistent with the section.

Section 117.1220, System Cap

The commission proposes a new §117.1220 that incorporates the rule language in the existing §117.108, relating to system cap, applicable to the Houston-Galveston-Brazoria ozone nonattainment area.

The commission proposes a new §117.1220(a) - (k) that incorporates the rule language in the existing §117.108(a) - (k). For proposed new §117.1220(b), the commission proposes to revise the language in existing §117.108(b) that specifies "that would otherwise be subject to the NO_x emission rates of §117.106 . . .." Proposed new §117.1220(b) specifies "that is subject to §117.1210(a) . . .." As previously discussed in this preamble, this change is necessary to clarify the commission's intent regarding units subject to the Mass Emission Cap and Trade Program. In addition, the commission proposes new equations in §117.1220(c) that incorporate the equations in existing §117.108(c) and present the equations in a format consistent with other equations in Chapter 117. The proposed new equations in §117.1220(c) include only the information applicable to the Houston-Galveston-Brazoria ozone nonattainment area. The proposed new equation in §117.1220(c)(1) incorporates the equation for the rolling 30-day average emission cap in the existing §117.108(c)(1). The proposed new equation in §117.1220(c)(2) incorporates the equation for the maximum daily emission cap in the existing §117.108(c)(2). The commission proposes a new §117.1220(k) that incorporates the requirements of the existing §117.108(k). The new §117.1220(k) changes source cap to system cap to be consistent with the section. Also, for proposed new §117.1220(k), the commission proposes to replace upset period with the language "emissions event, as defined in §101.1 of this title (relating to Definitions) . . .." This proposed change is necessary to update the rule to current terminology used by the commission.

The commission proposes a new §117.1220(l), relating to the use of emissions credits, that incorporates the rule language from existing §117.109, System Cap Flexibility. Proposed new §117.1220(m), relating to the sale and transfer of an electric generating system, incorporates the rule language from existing §117.110, Change of Ownership - System Cap.

Section 117.1225, Alternative Case Specific Specifications

The commission proposes a new §117.1225 that incorporates the rule language in the existing §117.121, relating to alternative case specific specifications, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.1225(a) and (b) incorporates the rule language in the existing §117.121(a) and (b). In addition, the proposed new §117.1225(a) omits the provision in the existing §117.121(a)(4) because the Engineering Services Team no longer exists within the TCEQ.

Section 117.1235, Initial Demonstration of Compliance

The commission proposes a new §117.1235 that incorporates the rule language in the existing §117.111, relating to initial demonstration of compliance, applicable to the Houston-Galveston-Brazoria ozone nonattainment area.

Section 117.1240, Continuous Demonstration of Compliance

The commission proposes a new §117.1240 that incorporates the rule language and requirements applicable to the Houston-Galveston-Brazoria ozone nonattainment area from existing §117.113, relating to initial demonstration of compliance, as well as the rule language and requirements from existing §117.114.

The commission proposes a new §117.1240(a) that incorporates the rule language in the existing §117.113(a), relating to NO_x monitoring. Proposed new §117.1240(b) incorporates the CO monitoring requirements from existing §117.113(b). The specific requirements and methods in the existing §117.113(b) appear in the proposed new §117.8120, relating to CO monitoring, and subsequently have been omitted from proposed new §117.1240(b) and replaced with a reference to the proposed new §117.8120.

The commission proposes a new §117.1240(c) that incorporates the rule language and ammonia monitoring requirements in existing §117.114(a)(4). The proposed new §117.1240(c) specifies that the owner or operator of units subject to the ammonia emission limits in the proposed new §117.1210(b)(2) shall comply with the ammonia monitoring requirements of the proposed new §117.8130. The specific ammonia monitoring procedures in existing §117.114(a)(4) are incorporated in proposed new §117.8130.

The requirements for CEMS in the existing §117.113(c)(1) and (2) appear in the proposed new §117.8110(a), relating to emission monitoring system requirements for utility electric generation sources. Therefore, the proposed new §117.1240(d) omits the specific requirements of existing §117.113(c)(1) and (2). Proposed new §117.1240(d)(1) refers to the proposed new §117.8110(a) for CEMS requirements applicable to units subject to the RACT emission specifications of proposed new §117.1205. Proposed new §117.1240(d)(2) incorporates the CEMS requirements for units subject to the emission specifications for attainment demonstration in proposed new §117.1210. Proposed new §117.1240(d)(2)(A) references to the proposed new §117.8110(a) and proposed new §117.1240(d)(2)(B) - (D) incorporate the existing rule language and CEMS requirements in existing §117.113(c)(3) that are specific to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.1240(e) incorporates the rule language from existing §117.113(d), concerning acid rain peaking units. Proposed new §117.1240(f) incorporates the rule language from existing §117.113(e), concerning auxiliary boilers. In addition, for proposed new §117.1240(f), the commission proposes to revise auxiliary boiler to auxiliary steam boiler to be consistent with the definition in §117.10.

The commission proposes a new §117.1240(g) that incorporates the requirements for PEMS from existing §117.113(f). Proposed new §117.1240(g)(1) incorporates the rule language from existing §117.113(f)(1). The requirements in the existing §117.113(f)(2) - (4) appear in the proposed new §117.8110(b), relating to emission monitoring system requirements for utility electric generation sources, and subsequently have been omitted from the proposed new §117.1240(g) and replaced with a reference to §117.8110(b) in proposed new §117.1240(g)(2).

Proposed new §117.1240(h) - (m) incorporate the rule language applicable to the Houston-Galveston-Brazoria ozone nonattainment area from existing §117.113(g) - (l), respectively. Proposed new §117.1240(n) incorporates the rule language from existing §117.114(b), and proposed new §117.1240(o) incorporates the rule language from existing §117.114(c). In addition, for proposed new §117.1240(o), the commission proposes to add language to specify "The owner or operator of units subject to §117.1210(a) of this title shall comply with the following." This change is necessary because the provisions of §117.114(c) only apply to sources subject to existing §117.106(c) and proposed new §117.1210(a).

The provisions in existing §117.114(a)(1) - (3), concerning monitoring requirements for NO_x, CO, and totalizing fuel flow meters, are redundant with existing requirements in §117.113 and proposed new §117.1240. Therefore, existing §117.114(a)(1) - (3) are not proposed to be incorporated in the proposed new §117.1240. Rule language from existing §117.114(a)(4)(E), concerning recordkeeping for ammonia monitoring, is proposed to be incorporated in proposed new §117.1245, Notification, Recordkeeping, and Reporting Requirements, to consolidate the recordkeeping requirements in the appropriate section.

Section 117.1245, Notification, Recordkeeping, and Reporting Requirements

The commission proposes a new §117.1245 that incorporates the rule language in the existing §117.119, relating to notification, recordkeeping, and reporting requirements, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.1245(a) - (e) incorporate the requirements in the existing §117.119(a) - (e). In addition, for proposed new §117.1045(a), the commission proposes to replace the language "the startup and/or shutdown exemptions allowed under §101.222" with "the startup and/or shutdown provisions of §101.222 . . .." The reference to exemptions is not applicable to §101.222 and the proposed change is necessary to clarify proposed new §117.1045(a). The commission is soliciting comments on this specific change to the language in existing §117.119(a). The commission is also soliciting comments on whether the reference to §101.222 should be removed. Finally, the commission proposes a new §117.1245(e)(8) that incorporates the recordkeeping requirement of the existing §117.114(a)(5)(E) associated with ammonia monitoring requirements.

Section 117.1252, Final Control Plan Procedures for Reasonably Available Control Technology

The commission proposes a new §117.1252 that incorporates the requirements in the existing §117.115, relating to final control plan procedures for RACT, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.1252(a), (b), and (c) incorporate the rule language from existing §117.115(a), (b) and (d), respectively. In addition, the commission proposes to omit the existing §117.115(c), relating to electronic submission and formatting requirements for the control plan, from the proposed new §117.1252. Existing §117.115 and proposed new §117.1252 specify the content requirements for the control plan. Therefore, a mandatory format for the control plan information is not necessary.

Section 117.1254, Final Control Plan Procedures for Attainment Demonstration Emission Specifications

The commission proposes a new §117.1254 that incorporates the rule language in the existing §117.116, relating to final control plan procedures for attainment demonstration emission specifications, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.1254(a) incorporates the rule language from existing §117.116(a). Proposed new §117.1254(a)(1)(A) that incorporates the existing §117.116(a)(1)(D), and replaces the existing §117.116(a)(1)(A). Proposed new §117.1254(a)(1)(B) and (C) incorporate the existing §117.116(a)(1)(B) and (D). Proposed new §117.1254(a)(2) - (5) incorporate rule language from the existing §117.116(a)(2) - (5), respectively. Finally, the commission proposes new §117.1254(b) and (c) that incorporate the rule language from existing §117.116(b) and (c), respectively.

Section 117.1256, Revision of Final Control Plan

The commission proposes a new §117.1256 that incorporates the requirements in the existing §117.117, relating to revision of final control plan, applicable to the Houston-Galveston-Brazoria ozone nonattainment area.

DIVISION 4, DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

The commission proposes a new Chapter 117, Subchapter C, Division 4, entitled Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources, that includes new rules applicable to utility electric generation sources in the Dallas-Fort Worth eight-hour ozone nonattainment area. These proposed new rules are one part of the commission's Dallas-Fort Worth eight-hour ozone attainment demonstration and are necessary for the area to demonstrate attainment.

Section 117.1300, Applicability

Proposed new §117.1300, concerning applicability, identifies the facilities and unit types in the Dallas-Fort Worth eight-hour ozone nonattainment area that would be subject to this proposed rule. Proposed subsection (a) specifies that the division applies to utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in turbine exhaust ducts used in an electric power generating system that is owned or operated by a municipality or a PUC-regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC, or owned be an electric cooperative, independent power producer, municipality, river authority, or public utility operating in the Dallas-Fort Worth eight-hour ozone nonattainment area.

Proposed subsection (b) specifies that the provisions of the propose rule are applicable for the life of each affected unit within an electric power generating system or until the rule, or sections of the rule that are applicable to an affected unit, are rescinded.

Section 117.1303, Exemptions

Proposed new §117.1303 specifies the unit types and conditions that qualify for exemption from the specifications of the proposed rule. Proposed new §117.1303(a), concerning exemptions from emission specifications for attainment demonstration, specifies the units exempt from the provisions of proposed §117.1310 and §117.1340, except as may be specified in proposed §117.1340(i) or (j). Units proposed for exemption include any new auxiliary steam boiler or stationary gas turbines placed into service after November 15, 1992, any auxiliary steam boiler with an annual heat input less than or equal to $2.2(10^{11})$ British thermal units per year, or stationary gas turbines and engines used solely to power other engines or gas turbines during startups or that are demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

Proposed new §117.1303(b) specifies the exemptions for emergency fuel oil firing conditions. Proposed new §117.1303(b)(1) specifies that the emissions specifications of proposed §117.1310 of this title do not apply during an emergency operating condition declared by the Electric Reliability Council of Texas, or any other emergency operating condition that necessitates oil firing. All findings that emergency operating conditions exist are subject to the approval of the executive director.

Proposed new §117.1303(b)(2) requires the owner or operator of an affected unit to provide the executive director, and any local air pollution control agency having jurisdiction, verbal notification as soon as possible but no later than 48 hours after declaration of the emergency. Verbal notification must identify the anticipated date and time oil firing will begin, duration of the emergency period, affected oil-fired equipment, and quantity of oil to be fired in each unit, and must be followed by written notification containing this information no later than five days after declaration of the emergency.

Proposed new §117.1303(b)(3) specifies that the owner or operator shall provide final written notification, as soon as possible but no later than two weeks after the termination of emergency fuel oil firing, to the executive director and any local air pollution control agency having jurisdiction. Final written notification must identify the actual dates and times that oil firing began and ended, duration of the emergency period, affected oil-fired equipment, and quantity of oil fired in each unit.

Section 117.1310, Emission Specifications for Eight-Hour Attainment Demonstration

The commission proposes a new section §117.1310 that specifies the proposed emission specifications for eight-hour attainment demonstration. The proposed new §117.1310(a) establishes proposed NO_x emissions specifications for units in the Dallas-Fort Worth eight-hour ozone nonattainment area that would be subject to this proposed rulemaking. In addition, emission specifications for RACT from existing §117.105 are proposed to satisfy RACT requirements for auxiliary steam boilers and stationary gas turbines in the Dallas-Fort Worth eight-hour ozone nonattainment area.

Proposed new §117.1310(a)(1) establishes an emission specification of 0.06 lb/MMBtu heat input from utility boilers that are part of a small utility system, as defined in §117.10. A NO_x emission specification of 0.033 lb/MMBtu heat input is proposed for utility boilers that are part of a large utility system, as defined in §117.10. The averaging times for these proposed emission specifications are on a rolling 24-hour average basis during the months of March through October of each calendar year, and on a rolling 30-day average basis during the months of November, December, January, and February of each calendar year. In addition, the commission is proposing a new output, or efficiency-based emission specification of 0.50 pounds per megawatt-hour output on an annual average basis.

Proposed new §117.1310(a)(2) specifies emission specifications for auxiliary steam boilers. Proposed subparagraph (A) establishes an emission specification of 0.26 lb/MMBtu heat input on a rolling 24-hour average and 0.20 lb/MMBtu heat input on a 30-day rolling average while firing natural gas or a combination of natural gas and waste oil. Proposed subparagraph (B) establishes an emission specification of 0.30 lb/MMBtu heat input on a rolling 24-hour averaging period while firing fuel oil only. The heat input weighted average of the applicable emission specifications specified in subparagraphs (A) and (B) on a rolling 24-hour averaging period while firing a mixture of natural gas and fuel oil is specified in proposed subparagraph (C). Proposed new subparagraph (C) also specifies the equation for calculating the emission specification while firing both natural gas and fuel oil. Also, for each auxiliary steam boiler that is an affected facility as defined by New Source Performance Standards (NSPS) 40 CFR Part 60, Subparts D, Db, or Dc, the applicable NSPS NO_x emission limit, unless the boiler is also subject to a more stringent permit emission limit, in which case the more stringent emission limit applies. Each auxiliary steam boiler subject to an emission specification under this subparagraph is not subject to the emission specifications of the subparagraphs of this paragraph. These emission specifications are identical to the current emission specifications for auxiliary steam boilers regulated under existing §117.105, concerning emission specifications for RACT, and the equation in proposed subparagraph (C) is identical to the equation provided in existing §117.105 for calculating the emission specification while firing both natural gas and fuel oil.

Proposed new §117.1310(a)(3) specifies emission specifications for stationary gas turbines. Proposed new subparagraph (A) establishes two emission specifications for stationary gas turbines with a MW rating greater than or equal to 30 MW and an annual electric output in megawatt-hr (MW-hr) of greater than or equal to the product of 2,500 hours and the MW rating of the unit. A NO_x emission specification of 42 ppmv at 15% O_2, dry basis, on a block one-hour average, is proposed for stationary gas turbines while firing natural gas, and an emission specification of 65 ppmv at 15% O_2, dry basis, is proposed for stationary gas turbines while firing fuel oil. Proposed subparagraph (B) establishes emission specifications for stationary gas turbines used for peaking service with an annual electric output in MW-hr of less than the product of 2,500 hours and the MW rating of the unit. The proposed NO_x emission specification under subparagraph (B) are 0.20 lb/MMBtu heat input, on a block one-hour average, while firing natural gas, and 0.30 lb/MMBtu heat input while firing fuel oil. These emission specifications are identical to the current RACT emission specifications for stationary gas turbines regulated under existing §117.105.

Proposed new §117.1310(b) establishes emission specifications of related emissions. For utility boilers or auxiliary steam boilers, a CO limit of 400 ppmv at 3.0% O_2, dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units and 0.31 lb/MMBtu heat input for oil-fired units), based on a one-hour average for units not equipped with a CEMS or PEMS for CO or a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO. For any stationary gas turbine with a MW rating greater than or equal to 10 MW, proposed §117.1310(b) establishes a CO emission specification of 132 ppmv at 15% O_2, dry basis. Proposed §117.1310(b)(2) specifies ammonia emission specifications for units that inject urea or ammonia into the exhaust stream for NO_x control, of 10 ppmv, at 3.0% O_2, dry, for boilers and 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), based on a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia. Units not subject to the ammonia emission specification in proposed §117.1310(b)(2)(A) are limited to a 20 ppmv ammonia emission specification under subparagraph (B), based on a block one-hour averaging period. This 20 ppmv ammonia emission specification is consistent with the current ammonia emission specification from existing §117.105 for RACT.

Proposed new §117.1310(c), concerning compliance flexibility, specifies that an owner or operator may use §117.9800 to comply with the NO_x emission specifications of this section. The subsection also specifies that proposed §117.1325 is not an applicable method of compliance with the NO_x emission specifications for this section. An owner or operator may petition the executive director for an alternative to the CO or ammonia specifications of proposed §117.1310 in accordance with proposed §117.1325.

Section 117.1325, Alternative Case Specific Specifications

Proposed new §117.1325 specifies that where a person can demonstrate that an affected unit cannot attain the applicable CO or ammonia emission specifications of proposed §117.1310(b), the executive director may approve emission specifications different from the CO or ammonia specifications in §117.1310(b) for that unit. Proposed §117.1325(a) specifies that the executive director shall consider on a case-by-case basis the technological and economic circumstances of the individual unit, shall determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the NO_x emission specifications of §117.1310, as applicable, and in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant that the unit is located to meet emission specifications through system-wide averaging at maximum capacity.

Proposed new §117.1325(b) specifies that any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. Proposed new subsection (b) also specifies that the requirements of §50.139 apply and that executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for EPA approval in some cases.

Section 117.1335, Initial Demonstration of Compliance

Proposed new §117.1335 specifies the procedures for the initial demonstration of compliance for owners or operators of units subject to the proposed rule. Proposed §117.1335(a) specifies that the owner or operator shall test for NO_x, CO, and O_2 emissions. Also, for units that inject urea or ammonia into the exhaust stream for NO_x control, the owner or operator must test for ammonia emissions. Testing must be performed in accordance with the schedules specified in proposed new §117.9130.

Proposed §117.1335(b) specifies that the tests required by subsection (a) must be used for determination of initial compliance with the proposed emission specifications. Test results must be reported in the units of the applicable emission specifications and averaging periods. If compliance testing is based on 40 CFR Part 60, Appendix A reference methods, the report must contain the information specified in proposed new §117.8010.

Proposed new §117.1335(c) specifies that CEMS or PEMS required by proposed new §117.1340 must be installed and operational before testing under subsection (a). Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

Proposed new §117.1335(d) specifies initial compliance with the emission specifications for units operating with CEMS or PEMS in accordance with proposed §117.1340 must be demonstrated after monitor certification testing using the NO_x CEMS or PEMS. Proposed paragraphs (1) - (5) specify the proper monitoring procedures to be followed for the different averaging times and units specified in the emission specifications of proposed §117.1310.

Section 117.1340, Continuous Demonstration of Compliance

Proposed new §117.1340 details the operating, monitoring, and testing required by owners and operators of units subject to the emissions specifications of proposed §117.1310 in order to demonstrate continuous compliance.

Proposed new §117.1340(a) requires the owner or operator of each unit subject to the emission specifications of this division to install, calibrate, maintain, and operate a CEMS, PEMS, or other system specified in proposed §117.1340, to measure NO_x on an individual basis. Each NO_x monitor (CEMS or PEMS) is subject to the RATA relative accuracy requirements of 40 CFR Part 75, Appendix B, Figure 2, except the concentration options (ppmv and lb/MMBtu) do not apply. Under proposed subsection (a), each NO_x monitor must meet either the relative accuracy percent requirement of 40 CFR Part 75, Appendix B, Figure 2, or an alternative relative accuracy requirement of ±2.0 ppmv from the reference method mean value.

Proposed new §117.1340(b), concerning CO monitoring, specifies the owner or operator shall monitor CO exhaust emissions from each unit subject to the emission specifications of proposed §117.1310, using one or more of the methods specified in proposed §117.8120. Proposed new §117.1340(c) requires the owner or operator of units that are subject to the ammonia emission specification of proposed new §117.1310(b)(2)(A) to comply with the ammonia monitoring requirements of proposed new §117.8130.

Proposed new §117.1340(d), concerning CEMS requirements, specifies that the owner or operator of any CEMS used to meet a pollutant monitoring requirement of proposed §117.1340 shall comply with the requirements of §117.8110(a).

Proposed new §117.1340(e) provides alternatives for NO_x monitoring for acid rain peaking units, as defined in 40 CFR §72.2, which are consistent with the alternatives of existing §117.113(d). Proposed new §117.1340(f) provides alternative NO_x monitoring provisions for auxiliary steam boilers. The owner or operator of each auxiliary steam boiler must either install, calibrate, maintain, and operate a CEMS in accordance with proposed new §117.1340, or comply with the appropriate (considering boiler maximum rated capacity and annual heat input) industrial boiler monitoring requirements of proposed new §117.440.

Proposed new §117.1340(g) details the requirements for any PEMS used to meet a pollutant monitoring requirement of this section. The required PEMS and fuel flow meters must be used to demonstrate continuous compliance with the proposed emission specifications. The PEMS must predict the pollutant emissions in the units of the applicable emission specification, and must meet the requirements of proposed new §117.8110(b).

Proposed new §117.1340(h), regarding stationary gas turbine monitoring, specifies the owner or operator of each stationary gas turbine subject to the emission specifications of §117.1310 of this title, instead of monitoring emissions in accordance with the monitoring requirements of 40 CFR Part 75, may comply with the following monitoring requirements. For stationary gas turbines rated less than 30 MW or peaking gas turbines that use steam or water injection to comply with the emission specifications of proposed new §117.1310(a)(3), the owner or operator may either install, calibrate, maintain and operate a CEMS or PEMS in compliance with proposed §117.1340, or install, calibrate, maintain, and operate a continuous monitoring system, accurate to within 5%, to monitor and record the average hourly fuel and steam or water consumption. The steam-to-fuel or water-to-fuel ratio monitoring data must be used for demonstrating continuous compliance with the applicable emission specification of proposed §117.1310. For stationary gas turbines subject to the emission specifications of proposed §117.1310 of this title, the owner or operator may install, calibrate, maintain and operate a CEMS or PEMS in compliance with proposed §117.1340.

Proposed new §117.1340(i), concerning totalizing fuel flow meters, specifies the owner or operator of units listed in subsection (i) shall install, calibrate, maintain, and operate totalizing fuel flow meters 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. In lieu of installing a totalizing fuel flow meter on a unit, an owner or operator may opt to assume fuel consumption at maximum design fuel flow rates during hours of the unit's operation. The units that the totalizing fuel flow meter requirements of proposed subsection (i) apply to include any unit subject to the emission specifications of proposed §117.1310, any stationary gas turbine with an MW rating greater than or equal to 1.0 MW operated more than 850 hours per year, and any unit claimed exempt from the emission specifications of using the low annual capacity factor exemption of proposed §117.1303(a)(2).

Proposed new §117.1340(j) specifies the owner or operator of any stationary gas turbine using the exemption of proposed §117.1303(a)(3) shall record the operating time with an elapsed run time meter.

Proposed new §117.1340(k), concerning monitoring for output-based NO_x emission specification, is a new eight-hour monitoring requirement detailing the monitoring required for the owner or operator of any unit that complies with the optional output-based NO_x emission specification in proposed new §117.1310(a)(1)(C). The proposed subsection requires the owner or operator to install, calibrate, maintain, and operate a system to continuously monitor, at least once every 15 minutes, and record the gross energy production of the unit in megawatt-hours (MW-hr). In addition, for each hour of operation, the owner or operator shall determine the total mass emission of NO_x, in pounds, from the unit using the NO_x monitoring requirements of proposed §117.1340(a) and the fuel monitoring requirements of proposed §117.1340(i). The owner or operator shall also, for each hour of operation, calculate and record the NO_x emissions in pounds per megawatt-hour.

Proposed new §117.1340(l), concerning loss of exemption, specifies the requirements for owners or operators of units claimed exempt under proposed new §117.1303(a)(2) or (3) that have lost exemption status because the applicable limit is exceeded.

Proposed new §117.1340(m), concerning data used for compliance, specifies that, after the initial demonstration of compliance required by proposed new §117.1335, the methods required in proposed new §117.1340 must be used for demonstrating continuous compliance with the emission specifications in proposed new §117.1310.

Section 117.1345, Notification, Recordkeeping, and Reporting Requirements

The proposed new §117.1345 specifies the notification, recordkeeping, and reporting requirements for owners or operators of units subject to the emission specifications of proposed §117.1310.

Proposed new §117.1345(a), concerning startup and shutdown records, specifies that 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 upon request by the executive director, EPA, and any local air pollution control agency having jurisdiction. These records include, but are not limited to: type of fuel burned; quantity of each type of fuel burned; gross and net energy production in MW-hr; and the date, time, and duration of the event.

Proposed new §117.1345(b), concerning notification, specifies the owner or operator of a unit subject to the emission specifications in proposed §117.1310 shall submit written notification to the appropriate regional office and any local air pollution control agency having jurisdiction of the date of any testing or any CEMS or PEMS performance evaluation conducted under §117.1335 or §117.1340 at least 15 days prior to such date.

Proposed new §117.1345(c) specifies 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 §117.1335 or any CEMS or PEMS performance evaluation conducted under §117.1340. Reports must be submitted within 60 days after completion of such testing or evaluation, and not later than the appropriate compliance schedules specified in proposed new §117.9130.

Proposed new §117.1345(d), concerning semiannual reports, specifies the owner or operator of a unit required to install a CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system under proposed §117.1340 shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations and the monitoring system performance. All reports must be postmarked or received by the 30th day following the end of each calendar semiannual period. The content requirements for the written reports are specified in proposed new paragraphs (1) - (5).

Proposed new §117.1345(e) specifies the recordkeeping requirement for the owner or operator of a unit subject to the proposed new Subchapter C, Division 4. Records must be kept for a period of at least five years and made available for inspection upon request by the executive director, EPA, or local air pollution control agencies having jurisdiction. Operating records for each unit must be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or for units claimed exempt from the emission specifications based on low annual capacity factor, monthly. Proposed new paragraph (1) requires records of emission rates in units of the applicable standards. Proposed new paragraph (2) requires records of gross energy production in MW-hr, except for auxiliary steam boilers and as specified in proposed new paragraph (8). Records of the quantity and type of fuel burned are required by proposed new paragraph (3), and the injection rate of reactant chemicals (if applicable) are required by proposed new paragraph (4). Proposed new paragraph (5) requires records of emission monitoring data, in accordance with proposed §117.1340, including: specified information regarding any monitoring system malfunctions; results of certification testing, evaluations, calibrations, checks, adjustments, and maintenance of monitoring systems; and actual emissions or operating parameter measurements, as applicable. Proposed new paragraphs (6) and (7) require records of performance testing results and hours of operation, respectively. Finally, proposed new paragraph (8) requires additional records for any unit that the owner or operator elects to comply with the output-based emission specification in §117.1310(a)(1)(C). The additional records include hourly records of the gross energy production in MW-hr, as well as records of hourly and annual average NO_x emissions in lb/MW-hr. In addition, proposed new paragraph (8) specifies that the averaging period for the annual average NO_x emissions in lb/MW-hr, for demonstrating continuous compliance is from January 1 through December 31 of each calendar year, beginning on January 1, 2010. This averaging period creates a temporary overlap with the initial demonstration of compliance period in proposed new §117.1335, but is necessary to reset the averaging period to a calendar-year basis.

Section 117.1350, Initial Control Plan Procedures

Proposed new §117.1350 requires the owner or operator of any unit in the Dallas-Fort Worth eight-hour ozone nonattainment area that is subject to proposed new §117.1310 to submit an initial control plan. Proposed new subsection (a) requires the control plan to include a list of all combustion units at the account that are listed in §117.1310. For each unit, the list must include the maximum rated capacity, anticipated annual capacity factor, estimated or measured NO_x emission data in the units associated with the category of equipment from §117.1310, the method of determination for the NO_x emission data, the facility identification number and emission point number as submitted to the Industrial Emissions Assessment Section of the commission, and the emission point number as listed on the Maximum Allowable Emissions Rate Table of any applicable commission permit. The list must also include identification of all units with a claimed exemption from the emission specifications in proposed §117.1310 and the rule basis for the claimed exemption, a list of units to be controlled and the type of control to be applied for each unit, including an anticipated construction schedule. For units required to install totalizing fuel flow meters in accordance with proposed §117.1340, the plan must indicate whether the devices are currently in operation, and if so, whether they have been installed as a result of the requirements of this proposed rule. For units required to install CEMS or PEMS, the plan must indicate whether the systems are currently in operation, and if so, whether they have been installed as a result of the requirements of this proposed rule.

Proposed new subsection (b) specifies that the initial control plan must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Chief Engineer's Office by the applicable date specified for initial control plans in proposed new §117.9130.

Finally, proposed new subsection (c) specifies that for units located in Dallas, Denton, Collin, and Tarrant Counties subject to proposed new §117.1110, the owner or operator may elect to submit the most recent revision of the final control plan required by proposed new §117.1154 in lieu of the initial control plan required by proposed §117.1350(a).

Section 117.1354, Final Control Plan Procedures for Attainment Demonstration Emission Specifications

Proposed new §117.1354 requires the owner or operator of utility boilers listed in proposed new §117.1300 at a major source of NO_x to submit a final control plan to show compliance with the requirements of proposed new §117.1310. The final control plans must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Chief Engineer's Office. As specified in proposed new §117.1354(a), the report must include: the methods of NO_x control for each utility boiler; the emissions measured by testing required in proposed §117.1335; the submittal date, and whether sent to the Austin or the regional office (or both), of any compliance stack test or RATA report required by §117.1335 not being submitted concurrently with the final compliance report; and the specific rule citation for any utility boiler with a claimed exemption. Proposed new §117.1354(b) specifies that the report must be submitted by the applicable date specified for final control plans in proposed new §117.9130.

Section 117.1356, Revision of Final Control Plan

Proposed new §117.1356 specifies the conditions under which a revised final control plan may be submitted by the owner or operator. The revised final control plan may be submitted along with any required permit applications. The section specifies that such a plan must adhere to the requirements and the final compliance dates, and that replacement new units may be included in the control plan. The revision of the final control plan is subject to the review and approval of the executive director.

SUBCHAPTER D, COMBUSTION CONTROL AT MINOR SOURCES IN OZONE NONATTAINMENT AREAS

The commission proposes a new Chapter 117, Subchapter D, entitled Combustion Control at Minor Sources in Ozone Nonattainment Areas, that incorporates the rule language from the existing Chapter 117, Subchapter D, Small Combustion Sources, Division 2, Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources.

In addition, the commission proposes a new Subchapter D, Division 2, entitled Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources, that includes new rule language and requirements associated with minor sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area. The new Subchapter D, Division 2 is proposed as a part of the commission's eight-hour ozone attainment demonstration for the Dallas-Fort Worth eight-hour ozone nonattainment area and is necessary for the area to demonstrate attainment.

DIVISION 1, HOUSTON-GALVESTON-BRAZORIA OZONE NONATTAINMENT AREA MINOR SOURCES

The commission proposes a new Subchapter D, Division 1, entitled Houston-Galveston-Brazoria Ozone Nonattainment Area Minor Sources, that incorporates the rule language from existing Subchapter D, Division 2. The existing Subchapter D, Division 2, is only applicable in the Houston-Galveston-Brazoria ozone nonattainment area.

Section 117.2000, Applicability

The commission proposes a new §117.2000 that incorporates the applicability rule language from existing §117.471.

Section 117.2003, Exemptions

The commission proposes a new §117.2003 that incorporates the exemption rule language from existing §117.473.

Section 117.2010, Emission Specifications

The commission proposes a new §117.2010 that incorporates the rule language from existing §117.475, concerning emission specifications. Proposed new §117.2010(a) - (i) incorporate the rule language from existing §117.475(a) - (i), respectively. In addition, for proposed new §117.2010(i)(2), the commission proposes to change the emissions specification for ammonia from the word "ten" to the numeral "10." Consistent with EPA guidance, the commission normally enforces emission test and monitoring results to the same significant figures as the emission specifications. Using the numeral "10" for the ammonia emission specification would ensure consistent enforcement of the emission specification.

Section 117.2025, Alternative Case Specific Specifications

The commission proposes a new §117.2025 that incorporates the rule language in the existing §117.481, relating to alternative case specific specifications. Proposed new §117.2025(a) and (b) incorporate the rule language in the existing §117.481(a) and (b), respectively. In addition, proposed new §117.2025(a) omits the existing §117.481(a)(4) because the Engineering Services Team no longer exists within the TCEQ.

Section 117.2030, Operating Requirements

The commission proposes a new §117.2030 that incorporates the rule language in the existing §117.478, relating to operating requirements. Proposed new §117.2030(a) - (c) incorporate the rule language in the existing §117.478(a) - (c), respectively. For proposed new §117.2030(a) and (b), the commission is proposing to revise the language in existing §117.478(a) and (b) that specifies unit or units "subject to the emission limitations of §117.475." Proposed new §117.2030(a) and (b) specify "subject to §117.2010 . . .." While compliance with the emission specifications in existing §117.475(c) is achieved through the Mass Emission Cap and Trade Program for sources that are required to participate in the program, and an individual unit may not necessarily be required to meet the applicable emission specification in §117.475(c), units subject to existing §117.475(c) are still required to comply with existing §117.478. This proposed change for proposed new §117.2030 would clarify the commission's intent and avoid misinterpretation of the rule requirements for units subject to the Mass Emission Cap and Trade Program. In addition, for proposed new §117.2030(b)(1), the commission proposes to omit the phrase "except for wood-fired boilers" because wood-fired boilers are not subject to either the existing rule or the proposed rule. The commission is concurrently proposing a new §117.8140(b) that incorporates the engine testing requirements in the existing §117.478(b)(5). Therefore, the engine testing requirements in existing §117.478(b)(5) have been omitted from the proposed new §117.2030(b)(5) and replaced with a reference to the proposed new §117.8140(b).

Section 117.2035, Monitoring and Testing Requirements

The commission proposes a new §117.2035 that incorporates the rule language regarding monitoring and testing from the existing §117.479, relating to monitoring, recordkeeping, and reporting requirements. Proposed new §117.2035(a) - (f) incorporate the rule language from existing §117.479(a) - (f), respectively. Proposed new §117.2035(g) incorporates the rule language from existing §117.479(i), concerning run time meters. The recordkeeping and reporting requirements in existing §117.479(g), (h), and (j) are proposed to be incorporated in a new proposed §117.2045, as discussed elsewhere in this preamble. In addition, for proposed new §117.2035, the commission is proposing to revise the language in existing §117.479(a) and (e) that specifies "subject to the emission limitations of §117.475." Proposed new §117.2035(a) and (e) would specify "subject to §117.2010 . . .." As previously indicated in this preamble, this proposed change would clarify the commission's intent and avoid misinterpretation of the rule requirements for units subject to the Mass Emission Cap and Trade Program.

For proposed new §117.2035(b) and (c), the references to existing §117.213(e) and (f) are proposed to be updated to §117.8100(a) and (b), as applicable, because the applicable requirements for CEMS and PEMS from existing §117.213 are proposed to be incorporated in a new §117.8100. For proposed new §117.2035(c), concerning NO_x monitors, the commission proposes to add a provision that specifies that if a PEMS is used, the PEMS must predict the pollutant emissions in units of the applicable emission specifications of the division. This change is necessary because this requirement from existing §117.213(f) is not included in the proposed new §117.8100(b).

The commission is concurrently proposing a new §117.8000 that incorporates some of the testing requirements in the existing §117.479(e)(3). Therefore, the commission proposes a new §117.2035(e)(3) that replaces specific requirements from existing §117.479(e)(3)(A) - (F) with a reference to the proposed new §117.8000. Existing §117.479(e)(3)(G), regarding the provision allowing the use of American Society for Testing and Materials (ASTM) D6522-00 for performance testing on natural gas-fired engines, turbines, boilers, and process heaters, is proposed to be incorporated into the new §117.2035(e)(3). Also, the commission is concurrently proposing a new §117.8010 that incorporates the report content requirements in the existing §117.211(g). Therefore, for proposed new §117.2035(e)(3), the reference to §117.211(g) in existing §117.479(e)(3)(G), for report content requirements, is revised to reference the proposed new §117.8010.

As indicated previously in this preamble, the commission is concurrently proposing a new §117.8010 that incorporates the report content requirements in the existing §117.211(g). Therefore, proposed new §117.2035(e)(4) changes the reference to §117.211(g) to the proposed new §117.8010. Also, for proposed new §117.2035(e)(6), the commission proposes to revise the language "Initial compliance with the emission specifications of §117.475" to specify that "Initial compliance with §117.2010 . . .." As indicated previously in this preamble, this proposed change would clarify the commission's intent and avoid misinterpretation of the rule requirements for units subject to the Mass Emission Cap and Trade Program.

Section 117.2045, Recordkeeping and Reporting Requirements

The commission proposes a new §117.2045 that incorporates the rule language regarding recordkeeping and reporting from the existing §117.479, relating to monitoring, recordkeeping, and reporting requirements. Proposed new §117.2045(a) - (c) incorporates the rule language from existing §117.479(g), (h), and (j), respectively. For proposed new §117.2045, the commission is proposing to revise the language in existing §117.479(g) that specifies "subject to the emission limitations of §117.475 . . .." Proposed new §117.2045(a) specifies "subject to §117.2010 . . .." As previously indicated in this preamble, this proposed change would clarify the commission's intent and avoid misinterpretation of the rule requirements for units subject to the Mass Emission Cap and Trade Program.

DIVISION 2, DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MINOR SOURCES

The commission proposes a new Subchapter D, Division 2, entitled Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources, that includes new rule language and requirements associated with minor sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area.

Section 117.2100, Applicability

Proposed new §117.2100 specifies that the new Division 2, Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources, applies to stationary reciprocating internal combustion engines, boilers, process heaters, gas turbines, and associated duct burners located in the Dallas-Fort Worth eight-hour ozone nonattainment area at a stationary source of NO_x that is not a major source of NO_x.

Section 117.2103, Exemptions

Proposed new §117.2103 would specify those boilers and process heaters, stationary, reciprocating internal combustion engines, and stationary gas turbines, including duct burners that would be exempt from the requirements of Chapter 117, Subchapter D, Division 2. Proposed new §117.2103(a)(1) exempts boilers and process heaters with a maximum rated capacity of 2.0 MMBtu/hr or less. This exemption level is proposed because units with a maximum rated capacity of 2.0 MMBtu/hr or less are already regulated under existing Subchapter B, Division 1, which is proposed to be incorporated in proposed new Subchapter E, Division 3.

In addition, proposed new §117.2103(a)(2)(A) - (G) would exempt stationary reciprocating internal combustion engines: with a hp rating of 50 hp or less; used for research and testing; used for performance verification and testing; used solely to power other engines and gas-turbines during startups; used exclusively for emergency situations, except for 52 hours of operation for testing and maintenance purposes; used in response to and during any officially declared disaster or state of emergency; or used directly and exclusively by the owner or operator for agricultural operations necessary for growing crops or raising of fowl or animals. The exemption in proposed new §117.2103(a)(2)(E), for engines used exclusively for emergency situations, would not be applicable to any new, modified, reconstructed, or relocated engines placed into service on or after June 1, 2007. Proposed new §117.2103(a)(2)(E) also provides the definitions for modified, reconstruction, or relocated.

Proposed new §117.2103(a)(2)(H), specifies that any stationary diesel engines placed into service before January 1, 2007, in the Dallas-Fort Worth eight-hour ozone nonattainment area is eligible for the exemption in §117.2103(a)(2)(H) provided the engine meets the conditions of clauses (i) and (ii). Proposed new §117.2103(a)(2)(H)(i) and (ii) specify that engines claimed exempt under §117.2103(a)(2)(H) must operate less than 100 hours per year, based on a rolling 12-month average and not have been modified, reconstructed, or relocated on or after January 1, 2007, in the Dallas-Fort Worth eight-hour ozone nonattainment area.

Proposed new §117.2103(a)(2)(I) specifies that any stationary diesel engines placed into service on or after January 1, 2007, in the Dallas-Fort Worth eight-hour ozone nonattainment area is eligible for the exemption in §117.2103(a)(2)(I) provided the engine meets the conditions of clauses (i) and (ii). Proposed new §117.2103(a)(2)(I)(i) and (ii) specify that new, modified, reconstructed, or relocated stationary diesel engines claimed exempt under §117.2103(a)(2)(I) must operate less than 100 hours per year, based on a rolling 12-month average, and must meet the corresponding emissions standards in 40 CFR §89.112(a), Table 1 (October 23, 1998) and in effect at the time of installation, modification, reconstruction, or relocation.

Proposed new §117.2103(a)(3) specifies that any stationary gas turbines rated at less than 1.0 megawatt with initial start of operation on or before June 1, 2007, in the Dallas-Fort Worth eight-hour ozone nonattainment area is exempt.

Proposed new §117.2103(b) establishes an exemption for certain low usage boilers and process heaters. Proposed new §117.2103(b)(1) provides an exemption for boilers and process heaters with the maximum rated capacity greater than 2.0 MMBtu/hr and less than 5.0 MMBtu/hr that have an annual heat input less than or equal to 1.8 (10^9) Btu per calendar year or a monthly average heat input less than or equal to 1.5 (10^8) Btu per month for the months of May through October. Proposed new §117.2103(b)(2) provides an exemption for boilers and process heaters with the maximum rated capacity greater than 5.0 MMBtu/hr that have an annual heat input less than or equal to 9.0 (10^9) Btu per calendar year or a monthly average heat input less than or equal to 7.5 (10^8) Btu per month for the months of May through October. The proposed annual fuel usage exemptions are consistent with the fuel usage exemptions applicable to minor sources of NO_x in the Houston-Galveston-Brazoria ozone nonattainment area. The commission is proposing the alternative monthly average-based exemption for the months of May through October to provide an exemption for sources, such as independent school districts, that have significant variation in seasonal usage and very low usage during typical ozone season months. The months of May through October represent the portion of ozone season for the Dallas-Fort Worth eight-hour ozone nonattainment area when the majority of ozone exceedances occur. This proposed exemption would allow sources that exceed the annual fuel usage criteria due to higher usage in winter months to still potentially qualify for exemption if usage during ozone-season months is sufficiently limited. However, the totalizing fuel flow requirements in §117.2135(a) and §117.2145(a)(1) would still apply to these exempted units in order to document that the annual or monthly heat input conditions of the exemption are being met.

Section 117.2110, Emission Specifications for Eight-Hour Attainment Demonstration

Proposed new §117.2110 establishes the proposed emission specifications for units in the Dallas-Fort Worth eight-hour ozone nonattainment area that would be subject to this rulemaking.

Proposed new §117.2110(a) establishes the NO_x emission specifications for each applicable category of units. Proposed new §117.2110(a)(1) establishes the NO_x emission specifications for boilers and process heaters. The proposed emission specification for gas-fired boilers and process heaters is 0.036

lb/MMBtu heat input or, alternatively, 30 ppmv, at 3.0% O_2, dry basis. The proposed emission specification for liquid-fired boilers and process heaters is 0.072 lb/MMBtu heat input or, alternatively, 60 ppmv, at 3.0% O_2, dry basis. The commission has determined that combustion modifications such as the installation of low-NO_x burners is expected to be the primary means of owners and operators to comply with the proposed emission specification for boilers and process heaters.

Proposed new §117.2110(a)(2) establishes NO_x emission specifications for stationary, gas-fired, reciprocating internal combustion engines. Gas-fired engines fired on landfill gas are proposed to be limited to 0.60 g/hp-hr and all other gas-fired engines are proposed to be limited to 0.50 g/hp-hr. NSCR technology is anticipated to be the primary control technology for rich-burn engines to comply with this proposed rule. In some cases, the owner or operator may have to install an additional catalyst module with the NSCR control package in order to comply with the 0.50 g/hp-hr emission specification. One possible control technology available for lean-burn engines is the application of an EGR kit (in order to reduce the excess O_2) combined with NSCR control. While NSCR is not normally applied to lean-burn engines, the use of the exhaust gas recirculation kit reduces exhaust gas O_2 and allows NSCR to be installed. It is possible that owners or operators of some lean-burn engines may not be able to apply the exhaust gas recirculation kit coupled with NSCR. In these instances, SCR may be required to achieve the proposed emission specifications. No landfill gas-fired engines were identified in the inventory in the counties impacted by this proposed rule; however, the 0.60 g/hp-hr for gas-fired engines fired on landfill gas is consistent with the emission specification for this category of engines in the Houston-Galveston-Brazoria ozone nonattainment area and is expected to be achievable through combustion modifications or by purchasing a new engine meeting the emission specification.

Stationary, dual-fuel, reciprocating internal combustion engines would be limited to 5.83 g/hp-hr by proposed new §117.2110(a)(3). For stationary, dual-fuel reciprocating internal combustion engines, combustion modifications are expected to be necessary to meet the 5.83 g/hp-hr emission specification requirements.

Proposed new §117.2110(a)(4) would establish emission specifications for stationary, diesel, reciprocating internal combustion engines based on engine hp rating and the date that the engine was installed, modified, reconstructed, or relocated. These emission specifications are similar to the emission specifications for stationary diesel engines subject to existing Subchapter D, Division 2 in the Houston-Galveston-Brazoria ozone nonattainment area; however, the commission is not proposing to require engines to meet previous specifications for which the dates have passed. Proposed new §117.2110(a)(4)(A) specifies that stationary diesel engines placed into service before June 1, 2007, that have not been modified, reconstructed, or relocated after June 1, 2007, would be limited to the lower of 11.0 g/hp-hr or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data. Section 117.2110(a)(4)(A) would define modification, reconstruction, and relocated consistent with §117.2010(c)(4). Proposed new §117.2110(a)(4)(B) would establish the NO_x emission limits for stationary diesel engines installed, modified, reconstructed, or relocated on or after June 1, 2007. The proposed emission specifications in §117.2110(a)(4)(B) are consistent with the standards for stationary diesel engines in the Houston-Galveston-Brazoria nonattainment area that have not yet passed by the time of the anticipated adoption date of this rulemaking.

The commission expects that the majority of stationary diesel engines at minor sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area would qualify for exemption under §117.2103(a)(2)(H) or (I). When owners or operators modify, reconstruct, or relocate existing stationary diesel engines on or after June 1, 2007, if used exclusively in emergency situations, these engines would continue to be exempt from the new emission specifications, but would be required to meet the EPA Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of installation, modification, reconstruction, or relocation. This would ensure that as turnover of older, higher-emitting stationary diesel engines occurs, the replacements would be cleaner engines. For engines that do not qualify for exemption, the commission does not anticipate that engines placed into service prior to June 1, 2007, would require combustion modifications to meet the 11.0 g/hp-hr emission specification. The cost of combustion modifications to stationary diesel engines to meet the emission standards proposed in §117.2110(a)(4)(B) is expected to be near the cost of a new engine; therefore, the commission anticipates that for engines placed into service on or after June 1, 2007, the owner or operator would likely purchase new equipment rather than retrofit or modify existing equipment.

In addition, the proposed new §117.2110(a)(5) establishes a NO_x emission specification of 0.15 lb/MMBtu heat input, approximately 42 ppmv, dry at 15% O_2, for stationary gas turbines and duct burners used in turbine exhaust ducts. For stationary gas turbines (including duct burners), the commission anticipates that combustion modifications such as water or steam injection would be necessary to achieve the proposed emission specification of 0.15 lb/MMBtu.

The proposed new §117.2110(a)(6), provides an alternative emission specification of 0.060 lb/MMBtu in lieu of the emissions specifications in §117.2110(a)(1) - (5) for a unit with an annual capacity factor of 0.0383 or less. The capacity factor as of December 31, 2000, must be used to determine eligibility for this alternative emission specification. For units placed into service after December 31, 2000, a 12-month rolling average must be used to determine the annual capacity factor.

Proposed new §117.2110(b) specifies that the averaging time for determining compliance with the NO_x emission specifications. Proposed new §117.2110(b)(1) specifies the averaging time for units equipped with CEMS or PEMS must be either a rolling 30-day average in the units of the applicable standard, a block one-hour average in the units of the applicable standard, or a block one-hour average in pounds per hour for boilers or process heaters. Proposed new §117.2110(b)(2) specifies that averaging time for units not operated with CEMS or PEMS must be a block one-hour average in the units of the applicable standard.

Proposed new §117.2110(c) specifies that the maximum rated capacity used to determine the applicability of the emissions specifications must be the greater of the maximum rated capacity as of December 31, 2000, or the maximum rated capacity after December 31, 2000. For example, if a boiler rated at 1.8 MMBtu/hr was placed into service prior to December 31, 2000, and then subsequently modified to increase its maximum capacity to 2.5 MMBtu/hr after December 31, 2000, that boiler would no longer qualify for the exemption under §117.2103(a)(1) and would be required to comply with the rule.

Proposed new §117.2110(d) specifies that 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 stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, would remain classified as a stationary gas-fired engine for the purposes of this proposed rule.

Proposed new §117.2110(e) specifies that changes after December 31, 2000, to a unit subject to an emission specification in subsection (a) that result in increased NO_x emissions from a unit not subject to the emission specifications is only allowed if the conditions of proposed §117.2110(e)(1) and (2) are met. Proposed §117.2110(e)(1) would require the increase in NO_x emissions at the unit not subject to an emission specification be determined using CEMS or PEMS monitoring or through stack testing that meets the requirements of §117.2135. In addition, proposed §117.2110(e)(2) would require that emission credits equal to the increase in NO_x emissions must be obtained and used in accordance with proposed new §117.9800, concerning use of emissions credits for compliance. An example of this is redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator or a flare.

Proposed new §117.2110(f) specifies that a source that met the definition of major source on December 31, 2000, must always be classified as a major source for purposes of this proposed rule. In addition, a source that was a minor source on December 31, 2000, but becomes a major source after December 31, 2000, would from that time forward always be classified as a major source for purposes of Chapter 117.

Proposed new §117.2110 also adds a new §117.2110(g) that specifies that the low annual capacity factor available under §117.2110(a)(6) for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. In addition, proposed §117.2110(g) specifies that reduced operation after December 31, 2000, cannot be used to qualify for a more lenient emission specification under subsection (a)(6).

Proposed new §117.2110(h) establishes ammonia and CO emission specifications. The CO emission specification in proposed §117.2110(h)(1) is 400 ppmv at 3.0 O_2, dry basis, or alternatively, 3.0 g/hp-hr for stationary internal combustion engines. Proposed new §117.2110(h)(1)(A) and (B) specify the averaging time for the CO emission specification. The CO specification is necessary to prevent large increases in CO emissions concurrent with the installation of NO_x controls, and represents good engineering practice. For units that inject urea or ammonia into the exhaust stream to control NO_x emissions, proposed §117.2110(h)(2) includes a 10 ppmv ammonia emission specification (at 3.0% O_2, dry basis, for boilers and process heaters; 15% O_2 for stationary gas turbines, including duct burners used in turbine exhaust ducts, and gas-fired lean-burn engines; and 3.0 O_2 for all other units). Proposed new §117.2110(h)(2)(A) and (B) specify the averaging time for the ammonia emission specification. This ammonia emission specification is necessary to ensure that excessive ammonia slip emissions do not occur should an owner or operator use a control technology such as SCR.

Finally, proposed new §117.2110(i) specifies that an owner or operator may use emission reduction credits as specified in proposed new §117.9800 to comply with the proposed NO_x emission specifications.

Section 117.2125, Alternative Case Specific Specifications

The commission proposes a new §117.2125, concerning alternative case specific specifications, that establishes provisions that allows owners or operators to petition the executive director for alternative case specific emission specifications for CO and ammonia. Proposed §117.2125(a) specifies that the executive director may approve emission specifications different from the CO or ammonia specifications for a unit where a person can demonstrate that the affected unit cannot attain the CO or ammonia specifications of §117.2110(h). Proposed subsection (a)(1) specifies that the executive director shall consider on a case-by-case basis the technological and economic circumstances of the individual unit. Proposed subsection (a)(2) requires that the executive director must determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the NO_x emission specifications of §117.2110. Proposed subsection (a)(3) specifies that the executive director, in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through system-wide averaging at maximum capacity. Finally, proposed §117.2125(b) specifies that any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision, and that the requirements of §50.139 (relating to Motion to Overturn Executive Director's Decision) apply to §117.2125.

Section 117.2130, Operating Requirements

The commission proposes a new §117.2130 that establishes operating requirements for units subject to the emission specifications of this division. Proposed new §117.2130(a) specifies that the owner or operator must operate any unit subject to the emission specifications in compliance with those specifications. Proposed new §117.2130(b) specifies that all units subject to the emission specifications 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.

Proposed new §117.2130(b)(1) requires each boiler to be operated with O_2, CO, or fuel trim. Proposed new §117.2130(b)(2) requires that each boiler and process heater controlled with forced 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. Proposed new §117.2130(b)(3) requires that 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. Proposed new §117.2130(b)(4) requires each stationary internal combustion engine controlled with NSCR to be equipped with an 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. Proposed new §117.2130(b)(5) requires that each stationary internal combustion engine must be checked for proper operation according to §117.8140(b). Proposed new §117.2130(c) specifies that 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 as provided in subsection (c)(1) - (3). Proposed new subsection (c)(1) allows for specific manufacturer's recommended testing requiring a run of over 18 consecutive hours. Proposed subsection (c)(2) allows for operation 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. Proposed new subsection (c)(3) allows for operation for firewater pumps for emergency response training conducted during April through October. This provision is identical to a requirement implemented for the Houston-Galveston-Brazoria ozone nonattainment area. The requirement, if adopted, would delay emissions of NO_x from testing of these engines until after noon in order to help limit ozone formation.

Section 117.2135, Monitoring, Notification, and Testing Requirements

The commission proposes a new §117.2135 that specifies the monitoring, notification, and testing requirements that apply to minor sources in the Dallas-Fort Worth eight-hour ozone nonattainment area subject to this proposed rule. Proposed new §117.2135(a) establishes totalizing fuel flow meter requirements. Proposed new §117.2135(a)(1) specifies the accuracy of totalizing fuel flow meters to an accuracy of ±5%. This subsection also allows the amount of fuel burned in pilot flames to be calculated using good engineering methods instead of requiring a separate fuel flow meter. The calculated result would be added to the metered value for total fuel use. Proposed new §117.2135(a)(2) specifies alternatives to the fuel flow monitoring requirements of this subsection. Proposed new §117.2135(a)(2)(A) provides an alternative to the total fuel flow meter requirements for independent school districts. Proposed new §117.2135(a)(2)(A)(i) specifies that owners or operators that elect to follow this alternative provision must maintain monthly records of fuel usage for the entire site and monthly records for each unit of the hours of operation, average operating rate, and estimated fuel usage. Proposed new §117.2135(a)(2)(A)(ii) specifies that within 60 days of written request by the executive director, the owner or operator must submit for review and approval all methods, engineering calculations, and process information used to estimate the hours of operation, operating rates, and fuel usage for each unit. Proposed new §117.2135(a)(2)(B) allows the owner or operator to share a single totalizing fuel flow meter on multiple units provided certain conditions are met. Proposed new §117.2135(a)(2)(B)(i) requires that all affected units at the site qualify for exemption under proposed new §117.2103(b). Proposed new §117.2135(a)(2)(B)(ii)(I) and (II) require that the total fuel usage for the site is less than the annual or monthly fuel usage limitation in §117.2103(b)(1), or the annual or monthly fuel usage limitation in §117.2103(b)(2) when all affected units at the site are equal to or greater than 5.0 MMBtu/hr.

Proposed new §117.2135(b) specifies that if an owner or operator installs an O_2 monitor, then the criteria in §117.8100(a) is the appropriate guidance for the location and calibration of the monitor. Proposed new §117.2135(c) specifies that if an owner or operator installs a NO_x monitor, then it must meet the CEMS or PEMS requirements of §117.8100(a) or (b). Proposed new §117.2135(d) specifies that monitors must be installed on the schedule specified in §117.9210.

Proposed new §117.2135(e) lists the testing requirements for units subject to the emission specifications of §117.2110. Proposed §117.2135(e)(1) requires that each unit must be tested for NO_x, CO, and O_2 emissions and proposed subsection (e)(2) requires that each unit that injects urea or ammonia for NO_x control be tested for ammonia emissions. Proposed new §117.2135(e)(3) specifies all testing must be conducted according to §117.8000 for units not equipped with CEMS or PEMS. In lieu of the test methods specified in §117.8000 of this title, the owner or operator may use ASTM D6522-00 to perform the NO_x, CO, and O_2 testing required by this subsection on natural gas-fired reciprocating engines, combustion turbines, boilers, and process heaters. Also, if the owner or operator elects to use ASTM D6522-00 for the testing requirements, the report must contain the information specified in §117.8010. Proposed new §117.2135(e)(4) specifies that the results must be reported in the units of the applicable standard and averaging periods, and that if compliance testing is based on 40 CFR 60 Appendix A test methods then the report must contain the information specified in §117.8010.

Proposed new §117.2135(e)(5) specifies that for units equipped with CEMS or PEMS, the CEMS or PEMS must be installed and operational before testing under this subsection. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device. Proposed new §117.2135(e)(6) specifies that on units operating with CEMS or PEMS, initial compliance with the emission specifications of §117.2110 of this title must be demonstrated using the CEMS or PEMS after monitor certification. Proposed new §117.2135(e)(7) specifies retesting requirements for units not operating with CEMS or PEMS. Proposed new §117.2135(e)(7)(A) requires retesting within 60 days after any modification that could reasonably be expected to increase the NO_x emission rate. Proposed new §117.2135(e)(7)(B) allows retesting at the discretion of the owner or operator after any modification that could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), FGR, and fuel-lean and conventional (fuel-rich) reburn. Proposed new §117.2135(e)(8) specifies that testing be performed in accordance with the schedule specified in §117.9210. Proposed new §117.2135(e)(9) requires that all test reports be submitted to the executive director for review and approval within 60 days after completion of the testing. Notification requirements are specified in proposed new §117.2135(e)(10). Written notification is required at least 15 days in advance of any testing or RATA required under §117.2135. Finally, proposed new §117.2135(f) specifies the owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.2103(a)(2)(E), (H), or (I) of this title shall record the operating time with a non-resettable elapsed run time meter.

Section 117.2145, Recordkeeping and Reporting Requirements

The commission proposes a new §117.2145 to specify recordkeeping and reporting requirements for sources subject to the proposed rule. Proposed new §117.2145(a) requires that the owner or operator of a unit subject to the emission specifications of §117.2110 must 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 EPA, or local air pollution control agencies having jurisdiction. Proposed new §117.3345(a)(1) specifies that, for units claimed exempt under proposed new §117.2103(b), records must be maintained of annual or monthly fuel usage, as applicable. Proposed new §117.3345(a)(2) requires that records of hourly emissions be maintained for each unit using a CEMS or PEMS. Proposed new §117.3345(a)(2)(A) requires hourly emissions for units complying with an emission specification enforced on a block one-hour average. Proposed new §117.3345(a)(2)(B) requires daily emissions for units complying with an emission specification enforced on a rolling 30-day average. Proposed new §117.3345(a)(2)(B)(i) and (ii) specify that emissions must be recorded in units of lb/MMBtu heat input and pounds or tons per day. Proposed new §117.2145(a)(3) specifies records for each stationary internal combustion engine subject to the emission specifications of §117.2110. Records required under proposed new §117.2145(a)(3) include emissions measurements required by §117.2130(b)(5) as well as any catalytic converter, AFR controller, or other emissions-related control system maintenance, including the date and nature of corrective actions taken. Proposed new subsection (a)(4) requires records of the CO measurements specified in subsection §117.2130(b)(5). Proposed new subsection (a)(5) requires 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. Proposed new subsection (a)(6) requires the owner or operator to maintain records of the results of performance testing.

Proposed new §117.2145(b) specifies that written records of the number of hours of operation for each day's operation must be made for each engine claimed exempt under §117.2103(a)(2)(E), (H), or (I) of this title or §117.2130(b)(5). In addition, for each engine claimed exempt under §117.2103(a)(2)(E), written records must be maintained that reflect 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 dates of the emergency situation. The records must be maintained for at least five years and must be made available upon request to representatives of the executive director, the EPA, or any local air pollution control agency having jurisdiction. Proposed new §117.2145(c) specifies the requirements for records of operation for testing and maintenance. The owner or operator of each stationary diesel or dual-fuel engine shall maintain the following records for at least five years and make them available upon request by authorized representatives of the executive director, the EPA, or local air pollution control agencies having jurisdiction. Proposed new §117.2145(c)(1) specifies the owner or operator of each stationary diesel or dual-fuel engine shall maintain records of dates of operation. Proposed new subsection (c)(2) requires records of start and end times of operation. Proposed new subsection (c)(3) requires records with engine identification and proposed new subsection (c)(4) requires records of the total hours of operation for each month and for the most recent 12 consecutive months.

SUBCHAPTER E, MULTI-REGION COMBUSTION CONTROL

The commission proposes a new Chapter 117, Subchapter E, entitled Multi-Region Combustion Control, that incorporates the portions of the existing Chapter 117 that are applicable to multiple regions of the state. Proposed new Subchapter E incorporates rules from existing Subchapter B, Divisions 2 and 4, and existing Subchapter D, Division 1. In addition, the commission proposes a new Subchapter E, Division 4, entitled East Texas Combustion, that proposes new rule language and requirements associated with stationary, gas-fired, reciprocating internal combustion engines in certain counties in the northeast Texas area. The new Subchapter E, Division 4 is proposed as a part of the commission's eight-hour ozone attainment demonstration for the Dallas-Fort Worth eight-hour ozone nonattainment area.

DIVISION 1, UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS

The commission proposes a new Chapter 117, Subchapter E, Division 1 to incorporate the rule language from existing Chapter 117, Subchapter B, Division 2, regarding utility electric generation in East and Central Texas.

Section 117.3000, Applicability

The commission proposes a new §117.3000 that incorporates the applicability language from existing §117.131.

Section 117.3003, Exemptions

The commission proposes a new §117.3003 that incorporates the exemption language from existing §117.133.

Section 117.3005, Gas-Fired Steam Generation

The commission proposes a new §117.3005 that incorporates the requirements and specifications from existing §117.134.

Section 117.3010, Emission Specifications

The commission proposes a new §117.3010 that incorporates the requirements and emission specifications from existing §117.135. The commission also proposes to correct a typographical error in existing §117.135(1) that incorrectly specified "nitrogen oxide (NO_x) . . .." The correct terminology is for the regulated pollutant is "nitrogen oxides (NO_x)." Because all other sections in the division correctly specify "nitrogen oxides," the commission does not anticipate that any regulated entities have misinterpreted the commission's intent with regard to the emission specifications in §117.135. Therefore, the commission does not consider the correction in proposed new §117.3010(1) to have any impact to the regulated community.

In addition, the commission proposes to revise the ammonia emission specification in proposed new §117.3010(2), incorporated from existing §117.135(2), to be the numeral "10" instead of the word "ten." Consistent with EPA guidance, the commission normally enforces emission test and monitoring results to the same significant figures as the emission specifications. Using the numeral "10" for the ammonia emission specification would ensure consistent enforcement of the emission specification. Finally, the commission proposes to move the existing requirement for ammonia monitoring procedures in existing §117.135(2)(B), that references the ammonia monitoring procedures in existing §117.114(a)(4) to the appropriate monitoring section in proposed new §117.3040, concerning continuous demonstration of compliance.

Section 117.3020, System Cap

The commission proposes a new §117.3020 that incorporates the language from existing §117.138, concerning System Cap requirements, and §117.139, concerning System Cap Flexibility. Existing §117.138(a) - (k) are proposed to be incorporated in proposed new §117.3020(a) - (k). Existing §117.139 is proposed to be incorporated in proposed new §117.3020(l). In addition, the commission proposes a revised equation in §117.3020(c) that incorporates the equation in existing §117.138(c) and presents the equation in a format consistent with other equations in Chapter 117.

Section 117.3025, Alternative Case Specific Specifications

The commission proposes a new §117.3025 that incorporates the provisions in the existing §117.151, relating to alternative case specific specifications. Proposed new §117.3025(a) and

(b) incorporates the rule language in the existing §117.151(a) and (b); however, the proposed new §117.3025(a) omits the existing §117.151(a)(4) because the Engineering Services Team no longer exists within the TCEQ.

Section 117.3035, Initial Demonstration of Compliance

The commission proposes a new §117.3035 that incorporates the requirements for initial demonstration of compliance from existing §117.141. Proposed new §117.3035(a) - (d) incorporate the rule language from existing §117.141(a) - (d). Additionally, in proposed new §117.3035(a), the commission proposes to revise the language from existing §117.141(a) to clarify that the units subject to the emission specifications should be tested, and not the owner or operator of the units.

Section 117.3040, Continuous Demonstration of Compliance

The commission proposes a new §117.3040 that incorporates the requirements for continuous demonstration of compliance from existing §117.143. Proposed new §117.3040(a) incorporates the rule language from existing §117.143(a). The CO monitoring provisions in existing §117.143(b) are incorporated in proposed new §117.3040(b); however, the actual monitoring methods in existing §117.143(b)(1) and (2) are proposed to be incorporated in proposed new §117.8120. Therefore, proposed new §117.3040(b) specifies that if the owner or operator chooses to monitor CO exhaust emissions, the methods specified in §117.8120 should be considered appropriate guidance for determining CO emissions.

Proposed new §117.3040(c) incorporates the ammonia monitoring provisions from existing §117.135(2)(B) because the continuous demonstration of compliance section is the most appropriate section for the ammonia monitor requirements. The ammonia monitoring procedures in existing §117.114(a)(4), referenced by existing §117.135(2)(B), are proposed to be incorporated in a new §117.8130. Proposed new §117.3040(c) specifies that, for units that inject urea or ammonia into the exhaust stream for NO_x control, one of the ammonia monitoring procedures in proposed new §117.8130 must be used to demonstrate compliance with the ammonia emission specification.

Proposed new §117.3040(d) incorporates the CEMS requirements from existing §117.135(c). The requirements for CEMS in existing §117.135(c) are sufficiently different from the requirements in §117.113(e) that referencing the general CEMS requirements for utility electric generation sources in proposed new §117.8110(a) would result in substantive changes to the requirements for affected CEMS. Therefore, the commission is not proposing to merge the CEMS requirements in existing §117.135(c) with proposed new §117.8110(a).

Proposed new §117.3040(e) incorporates the rule language from existing §117.135(d), concerning monitoring for acid rain peaking units. The commission proposes a new §117.3040(f) that incorporates the rule language from existing §117.135(e), concerning PEMS requirements. Proposed new §117.3040(f)(1) incorporates the provision in existing §117.135(f)(1), that specifies that the PEMS must predict the pollutant emissions in the units of the applicable emission specifications of the division. The commission proposes a new §117.3040(f)(2) that references the proposed new §117.8110(b) as a replacement for the rule language in existing §117.135(f)(2) - (4). The general requirements for PEMS in proposed new §117.8110(b) are identical to the requirements in existing §117.135(f)(2) - (4).

Finally, the commission proposes new §117.3040(g) - (l) that incorporate the rule language from existing §117.135(f) - (k), respectively.

Section 117.3045, Notification, Recordkeeping, and Reporting Requirements

The commission proposes a new §117.3045, concerning notification, recordkeeping, and reporting requirements, that incorporates the rule language from existing §117.149. Proposed new §117.3045(a) - (e) incorporate the rule language from existing §117.149(a) - (e). In addition, for proposed new §117.3045(a), the commission proposes to replace the language "the startup and/or shutdown exemptions allowed under §101.222" with "the startup and/or shutdown provisions of §101.222 . . .." The reference to exemptions is not applicable to §101.222 and the proposed change is necessary to clarify proposed new §117.3045(a). The commission is soliciting comments on this specific change to the language in existing §117.149(a). The commission is also soliciting comments on whether the reference to §101.222 should be removed.

Section 117.3054, Final Control Plan Procedures

The commission proposes a new §117.3054, concerning final control plan procedures, that incorporates the rule language from existing §117.145.

Section 117.3056, Revision of Final Control Plan

The commission proposes a new §117.3056, concerning revision of final control plan, that incorporates the rule language from existing §117.147.

DIVISION 2, CEMENT KILNS

The commission proposes a new Chapter 117, Subchapter E, Division 2 to incorporate the rule language from existing Chapter 117, Subchapter B, Division 4, regarding cement kilns. In addition, the commission proposes new control, monitoring, testing, and recordkeeping requirements for cement kilns in Ellis County as a part of the commission's Dallas-Fort Worth eight-hour ozone attainment demonstration.

Section 117.3100, Applicability

The commission is proposing new §117.3100 that incorporates the applicability rule language from existing §117.261. In addition, the language in existing §117.261, regarding applicability of the rule to units placed into service before December 31 1999, is proposed to be moved to the proposed new §117.3103, Exemptions.

Section 117.3101, Cement Kiln Definitions

The commission is proposing new §117.3101 that incorporates the definition rule language from existing §117.260.

Section 117.3103, Exemptions

The commission is proposing new §117.3103, concerning exemptions, that incorporates the exemption in applicability language of existing §117.261 that exempted certain units placed into service on or after December 31, 1999, and proposes a new exemption regarding units subject to proposed new §117.3123. The proposed new §117.3103(a) specifies that units exempted from the division include any portland cement kiln placed into service on or after December 31, 1999, except as specified in proposed new §§117.3110, 117.3120, and 117.3123. Proposed new §117.3110 and §117.3120 are corresponding new sections that incorporate existing rule language from existing §117.265

and §117.283, respectively, which are already referenced in the existing language in §117.261. The reference to proposed new §117.3123 is necessary to ensure that cement kilns located at existing accounts in Ellis County, regardless of date placed into service, are subject to the proposed emission control requirements for the Dallas-Fort Worth eight-hour attainment demonstration described in §117.3123 and other associated requirements discussed later in this preamble.

Proposed new §117.3103(b) specifies that any account in Ellis County that had no portland cement kilns in operation prior to January 1, 2001, is exempt from proposed new §117.3123. All existing accounts are proposed to be regulated under the source cap control measure in proposed new §117.3123, including any new kilns placed into service at those accounts. Any newly permitted accounts would be addressed under New Source Review permitting. Proposed new §117.3103(c) specifies that §117.3110 and §117.3120 would no longer apply to cement kilns subject to §117.3123 after the compliance date specified in proposed new §117.9320(c). This provision is necessary to avoid overlapping requirements for sources that are subject to the mandatory source cap requirement in proposed new §117.3123.

Section 117.3110, Emission Specifications

The commission is proposing a new §117.3110 that incorporates the rule language regarding emission specifications from existing §117.265. Proposed new §117.3110(a) - (e) incorporate the rule language from existing §117.265(a) - (e).

Section 117.3120, Source Cap

The commission is proposing new §117.3120 that incorporates the rule language from existing §117.283. Proposed new §117.3120(a) - (f) incorporate the rule language from existing §117.283(a) - (f), respectively. In addition, the commission proposes a new equation in §117.3120(a) that incorporates the equation in existing §117.283(a). The proposed new equation in §117.3120(a) presents the equation in a format consistent with other equations in Chapter 117 and provides a definition for each term used in the equation.

Section 117.3123, Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements

The commission is proposing a new §117.3123, entitled Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements, that includes a new mandatory source cap requirement for all units located in Ellis County. Proposed new §117.3123(a) specifies that the owner or operator of any portland cement kiln in Ellis County shall not allow the total NO_x emissions from all cement kilns located at the account to exceed the source cap limitation in proposed new §117.3123(b). Proposed new §117.3123(a) also specifies that compliance with the source cap must be in accordance with the compliance schedule in proposed new §117.9320(c).

Proposed new §117.3123(b) specifies that the NO_x source cap for an account subject to proposed new §117.3123 must be calculated according to the equation in proposed new §117.3123(b). The source cap for an account is determined according to the equation in proposed new §117.3123(b), the number and type of cement kilns located at the account, and specified NO_x emission factors for each type of kiln. The source cap, identified as resultant Cap_{8hour} in the equation, is the total allowable NO_x emissions from all cement kilns located at an account in tons per day and on a 30-day rolling average basis. The NO_x emission factor to determine the cap contribution from each dry preheater-precalciner or precalciner kiln, variable K_D, is 2.84 tons per day. The NO_x emission factor to determine the cap contribution from each long wet kiln, variable K_W, is 1.39 tons per day. Variables N_D and N_W are the total number of dry preheater-precalciner or precalciner kilns and long wet kilns located at the account and operational during calendar year 2000. The total source cap for an account subject to proposed new §117.3123 would be the product of variables K_D and N_D, plus the product of variables K_W and N_W. Cement kilns that began operation after calendar year 2000 would be excluded from the calculation of the source cap; however, as described later in this preamble, NO_x emissions from cement kilns that began operation after calendar year 2000 would be included in the total emissions accounted for when determining compliance with the source cap. This approach is consistent with source cap option currently allowed under existing §117.283. The emission factors used for the source cap calculation, K_D and K_W, were determined based on the future 2009 projected emission rates from the commission's modeling sensitivities study using 35 - 50% controls. Variable K_D, 2.84 tons per day, is the average of the 2009 projected controlled NO_x emissions of all dry preheater-precalciner or precalciner kilns from the modeling sensitivity study. Variable K_W, 1.39 tons per day, is the average of the 2009 projected controlled NO_x emissions of five of the seven long wet kilns from the modeling sensitivity study.

Proposed new §117.3123(c) specifies the NO_x emission monitoring requirements of proposed new §117.3142 must be used to demonstrate continuous compliance with the source cap. Proposed new §117.3123(d) specifies the requirements that apply to kilns that were not operational prior to calendar year 2001. Proposed new §117.3123(d)(1) specifies that a cement kiln not in operation prior to calendar year 2001 is subject to the source cap but must not be included in the source cap calculation in proposed new §117.3123(b). Proposed new subsection (d)(2) specifies that the requirements of proposed new §117.3142 and §117.3145 apply, and proposed new subsection (d)(3) specifies that the NO_x emissions from the kiln must be included in the calculation of the rolling 30-day average for compliance with the source cap. The intent of the source cap in proposed new §117.3123 is to establish a maximum cap on the total NO_x emissions from cement kilns at each account, based on the number of kilns in operation in calendar year 2000. The provisions of proposed new §117.3123(d) prohibit expanding the source cap based on new units installed after calendar year 2000.

The commission proposes a new §117.3123(e) that requires the owner or operator to submit a control plan for compliance with the source cap. Control plans are required to be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Chief Engineer's Office. Proposed new §117.3123(e)(1) specifies the minimum content of the control plan, including: the emission point number for each kiln at the account; the facility identification number for each kiln at the account; the source cap for the account calculated according to the equation in proposed new §117.3123(b); and a description of the control measures that have been or will be implemented for each cement kiln for compliance with the source cap. Proposed new §117.3123(e)(2) provides for revisions to the control plan and specifies that the revised control plan must be submitted with any required permit application. The revised control plan must adhere to the requirements of the rule.

Proposed new §117.3123(f) specifies an ammonia emission specification of 10 ppmv at 7% O_2 for units that inject ammonia or urea to control NO_x emissions. Because SNCR and SCR are among the potential control technologies available for compliance with the source cap, an ammonia emission specification is necessary to prevent excessive ammonia slip.

Finally, proposed new §117.3123(g) provides compliance flexibility by allowing owners or operators to comply with the proposed source cap limitation, in whole or in part, using emission reduction credits as provided in proposed new §117.9800.

Section 117.3125, Alternative Case Specific Specifications

The commission is proposing new §117.3125 that sets forth provisions for alternative case emission specifications for ammonia. Proposed §117.3125(a) specifies that the executive director may approve emission specifications different from the ammonia specification for a unit where a person can demonstrate that the affected unit cannot attain the ammonia specification of §117.3123(f). Proposed subsection (a)(1) specifies that the executive director shall consider, on a case-by-case basis, the technological and economic circumstances of the individual unit. Proposed subsection (a)(2) requires that the executive director must determine that such specifications are the result of the lowest emission specification the unit is capable of meeting after the application of controls to meet the NO_x emission specifications of §117.3123. Proposed subsection (a)(3) specifies that the executive director, in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through system-wide averaging at maximum capacity. Finally, proposed §117.3125(b) specifies that any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision, and that the requirements of §50.139 apply to §117.3125.

Section 117.3140, Continuous Demonstration of Compliance

The commission proposes a new §117.3140 that incorporates the rule language from existing §117.243, concerning continuous demonstration of compliance. Proposed new §117.3140(a) - (c) incorporate the rule language from existing §117.273(a) - (c), respectively. In addition, for proposed new §117.3140(c)(2), the cross-reference to existing §117.213(f)(2) - (7) is proposed to be changed to new §117.8100(b) because the applicable requirements for PEMS in existing §117.213(f)(2) - (7) are proposed to be incorporated in proposed new §117.8100(b).

Section 117.3142, Emission Testing and Monitoring for Eight-Hour Attainment Demonstration

The commission is proposing a new §117.3142 that specifies emission testing and monitoring requirements for units subject to the source cap in proposed new §117.3123. Proposed new §117.3142(a) specifies that the owner or operator of any portland cement kiln subject to proposed new §117.3123 must comply with the monitoring requirements in proposed new §117.3142(a)(1) - (4). Proposed new §117.3142(a)(1) specifies that the NO_x monitoring requirements of §117.3140 apply. The affected facilities are already required to monitor NO_x emissions under either existing §117.473, which is proposed to be incorporated in the new §117.3140, or due to TCEQ air permit requirements. In addition, proposed new §117.3142(a)(1)(A) - (C) specify additional requirements for NO_x CEMS. Proposed new subparagraph (A) requires that each individual stack must be analyzed for NO_x separately for single units with multiple exhaust stacks. Proposed new subparagraph (B) allows sharing of CEMS among units or among multiple exhaust stacks on a single unit provided the conditions of subparagraph (B)(i) and (ii) are met. Proposed new §117.3142(a)(1)(B)(i) requires that exhaust of each stack is analyzed and reported separately, and proposed new §117.3142(a)(1)(B)(ii) requires that the CEMS meet the certification requirements in §117.3140(b) for each exhaust stream while the CEMS is operating in time-shared mode. Proposed new §117.3142(a)(1)(C) requires that all bypass stacks be monitored to quantify emissions directed through the bypass stack. If the CEMS is located upstream of the bypass stack to satisfy this requirement, the proposed new clauses (i) and (ii) specify additional requirements for monitoring of bypass stacks. Proposed new clause (i) specifies that no stream from other potential sources of NO_x may be introduced between the CEMS and the bypass stack. Proposed new clause (ii) requires the owner or operator to install, operate, and maintain a continuous monitoring system to record automatically the date, time, and duration of each event when the bypass stack is open. These additional requirements for CEMS are necessary to ensure that NO_x emissions are accurately quantified for compliance with the source cap in proposed new §117.3123.

The commission also proposes a new §117.3142(a)(2) to require monitoring of stack exhaust flow rate using the monitoring specifications of 40 CFR Part 60, Appendix B, Performance Specification 6, or 40 CFR Part 75, Appendix A. This new flow monitoring requirement is necessary to ensure that total NO_x emissions are accurately quantified for compliance with the new source cap in proposed new §117.3123. The affected facilities in Ellis County are already required to perform similar flow monitoring due to the TCEQ air permit requirements. Therefore, this proposed new flow monitoring requirement should not require the installation of any new monitoring equipment. In addition, the certification requirements proposed in new §117.3142(a)(2) are similar to the flow monitor certification requirements already required for the monitoring systems by permit.

For units that inject ammonia or urea to control NO_x emissions, proposed new §117.3142(a)(3) requires that ammonia emissions must be monitored according to either proposed new §117.8130(1), (2), or (4). These ammonia monitoring procedures include the mass balance approach, the oxidation of ammonia to nitric oxide approach, or other methods approved by the executive director. The method of stain tubes method in §117.8130(3) is not appropriate for cement kilns in determining compliance with the ammonia emission specification in §117.3123(f) due to the infrequency of sample collection using this method and the potential high variability of ammonia emissions from kilns using urea or ammonia injection for NO_x control. The commission proposes a new §117.3142(a)(4) specifying that the installation of monitors must be performed in accordance with the schedule specified in §117.9320(c).

The commission also proposes a new §117.3142(b) that specifies the calculations and equations used to demonstrate compliance with the source cap. Proposed new §117.3142(b)(1) specifies the equation used to calculate hourly NO_x emissions from each kiln, in pounds per hour, identified as resultant "EH" in the equation. Variable "C" is the block hour average NO_x concentration in ppmv, dry basis, corrected to 7% O_2. Variable "F" is the block hour average exhaust flow rate in dry standard cubic feet per minute, corrected to 7% O_2, and variable "K" is a conversion factor from 40 CFR 60, Appendix A, Method 19 for calculating NO_x mass emission rates from ppmv concentrations. Proposed new §117.3142(b)(2) specifies the equation for calculating the total daily NO_x emissions, expressed as resultant "ED" in the equations, in tons per day from the hourly emissions determined according to proposed new subsection (b)(1) and the number of hours of operation per day for each kiln, expressed as variable "N" in the equation. Proposed new §117.3142(b)(3) specifies the equation for determining the rolling 30-day average NO_x emissions, expressed as resultant "E_{30day}" in the equation, in tons per day for the account, computed for the preceding 30 days. The rolling 30-day average is calculated based on the total daily NO_x emissions from each kiln determined according to proposed new subsection (b)(2), the number of kilns located at the account, expressed as variable "K," and the preceding 30 days, expressed as variable "N" in the equation.

Section §117.3145, Notification, Recordkeeping, and Reporting Requirements

The commission is proposing a new §117.3145 that incorporates the rule language from existing §117.279, concerning notification, recordkeeping, and reporting requirements. Proposed new §117.3145(a) - (c) incorporates the notification, recordkeeping, and reporting rule language from existing §117.279(a) - (c). In addition, modifications to the existing rule language and additional requirements are proposed for the sources subject to the proposed new source cap in §117.3123. For proposed new §117.3145(a), concerning notification, the commission proposes to add a reference to proposed new §117.3142 to the existing language from §117.279. This change is necessary to require notification of any CEMS or PEMS performance evaluation for monitoring systems required under §117.3142. Similarly, the commission proposes to add a reference to proposed new §117.3142 in proposed new §117.3145(b) to require reporting of test results for any CEMS or PEMS relative accuracy test audit. Proposed new §117.3145(c)(1) is revised to specify that for each kiln subject to §117.3110 or §117.3120, the records in subparagraphs (A) - (C) are required. This change is necessary to clarify that sources subject to the source cap in §117.3123 are not required to maintain the records under §117.3145(c)(1)(A) - (C). In addition, for proposed new §117.3145(c)(1)(B), the commission is proposing to revise the language from existing §117.279(c)(1)(B) to specify that records of the production of clinker should be in United States short tons. Metric tons are typically used by the cement manufacturing industry to express production and this change is necessary to clarify the appropriate units for the records and for the emissions calculated in pounds per ton of clinker.

Proposed new §117.3145(c)(4) specifies new recordkeeping requirements for each kiln subject to the source cap in proposed new §117.3123 and the monitoring requirements of proposed new §117.3142. Proposed new §117.3145(c)(4)(A) requires records of the control plan required by proposed new §117.3123. Proposed new §117.3145(c)(B) and (C) require hourly records of the average NO_x concentration in ppmv, dry basis, at 7% O_2, and hourly records of the NO_x emission in pounds per hour. Proposed new §117.3145(c)(4)(D) and (E) require daily records of the NO_x emissions from each kiln in tons per day, and daily records of the NO_x emissions in tons per day expressed as rolling 30-day average. Proposed new §117.3145(c)(4)(F) requires hourly records of the average exhaust gas flow rate in dry standard cubic feet per minute, corrected to 7% O_2, and proposed new §117.3145(c)(4)(G) requires records of the ammonia monitoring required under proposed new §117.3142(a)(3).

DIVISION 3, WATER HEATERS, SMALL BOILERS, AND PROCESS HEATERS

The commission proposes a new Chapter 117, Subchapter E, Division 3 to incorporate the rule language from existing Chapter 117, Subchapter D, Division 1, regarding water heaters, small boilers, and process heaters.

Section §117.3200, Applicability

The commission proposes a new §117.3200 that incorporates the applicability rule language from existing §117.461.

Section 117.3201, Definitions

The commission proposes a new §117.3201, concerning definitions, that incorporates the rule language from existing §117.460. In addition, the commission proposes to delete the definitions of direct-vent unit and power-vent unit. These definitions were added in the previous rulemaking because direct-vent and power-vent units were not required to meet the 10 ng/J NO_x emission standard. Because proposed new §117.3205, concerning emission specifications, specifies the same standard for all Type 0 water heaters manufactured on or after July 1, 2002, the separate emission specifications and definitions for direct-vent and power-vent units are superfluous. Subsequent definitions are renumbered accordingly.

Section 117.3203, Exemptions

The commission proposes a new §117.3203 that incorporates the rule language regarding exemptions from existing §117.463. In addition, for proposed new §117.3203(3), the commission proposes to change the exemption in existing §117.463(3), concerning Type 0 units used exclusively to heat swimming pools and hot tubs. Proposed new §117.3203(3) adds language to allow Type 1 and 2 units at single-family residences to qualify for this exemption. It was the commission's intent that the exemption in existing §117.463(3) apply to water heaters used exclusively to heat swimming pools and hot tubs at single-family residences. It was anticipated that only Type 0 units would be used for this purpose. It has come to the commission's attention that some single-family residences have installed Type 1 or 2 units to heat swimming pools and hot tubs. Therefore, the commission is proposing this change to clarify the intent of the exemption. Type 1 and 2 units installed after the appropriate compliance dates at multi-family residences or commercial properties are still required to comply with emission limits set forth in proposed new §117.3205.

Section 117.3205, Emission Specifications

The commission proposes a new §117.3205, concerning emission specifications, that incorporates the rule language from existing §117.465. Also, the commission proposes changes to existing §117.465(b) to implement the requirements of HB 965. For proposed new §117.3205(b)(1), the language "but no later than December 31, 2006," in existing §117.465(b)(1) is proposed to be removed to clarify that Type 0 units manufactured after July 1, 2002, must comply with the requirements in subsection (b)(1)(A) and (B) of this section. As previously discussed in this preamble, the existing NO_x emission specifications, 10 ng/J of heat output or 15 ppmv at 3.0% O_2, in existing §117.465(b)(2)(A) for Type 0 units (except power-vent and direct-vent units) are proposed to be repealed. Therefore, proposed new §117.3205(b) excludes these emission specifications for Type 0 units.

In addition, the emission specifications for power-vent and direct-vent units in existing §117.465(b)(2)(B) are identical to the emission specifications in existing §117.465(b)(1) and proposed new §117.3205(b)(1). Therefore, proposed new §117.3205(b) excludes the emission specifications for power-vent and direct-vent units from existing §117.465(b)(3). All Type 0 gas-fired water heaters, including power-vent and direct vent units, manufactured on or after July 1, 2002, would be subject to the NO_x

emissions specifications in proposed new §117.3205(b)(1). Finally, proposed new §117.3205(b)(2) and (3) incorporate the rule language from existing §117.465(b)(4) and (5), respectively, concerning the emission specifications for Type 1 and 2 units.

Section 117.3210, Certification Requirements

The commission proposes a new §117.3210 that incorporates the rule language from existing §117.467, concerning certification requirements. Proposed new §117.3210(a) and (b) incorporate the requirements from existing §117.467(a) and (b), respectively. In addition, for proposed new §117.3210(a), the commission proposes to remove the date reference for Test Method 7. This proposed change would allow the most recent versions of EPA Test Methods 7 through 7E to be used for the certification testing.

Section 117.3215, Notification and Labeling Requirements

The commission proposes a new §117.3215 that incorporates the rule language from existing §117.469, concerning notification and label requirements.

DIVISION 4, EAST TEXAS COMBUSTION

The commission proposes a new Chapter 117, Subchapter E, Division 4, regarding new requirements for stationary, gas-fired reciprocating internal combustion engines in specified counties in the northeast Texas area. The new Subchapter E, Division 4 is proposed as a part of the commission's eight-hour ozone attainment demonstration for the Dallas-Fort Worth eight-hour ozone nonattainment area. Any engines located in the Dallas-Fort Worth eight-hour ozone nonattainment area would not be subject to this proposed rule. Engines located in the Dallas-Fort Worth eight-hour ozone nonattainment area that would otherwise be subject to this proposed rule, are either currently regulated by equivalent or more stringent requirements under other divisions of Chapter 117, or are proposed to be regulated in separate rulemakings concurrent with this proposed rule. Therefore, applying this rule to the Dallas-Fort Worth eight-hour ozone nonattainment counties would be superfluous.

Section 117.3300, Applicability

The proposed new §117.3300 specifies that the new division would apply to stationary, gas-fired reciprocating internal combustion engines in certain counties in the northeast Texas area. The specific counties included in the applicability for this rulemaking include the following counties: Anderson, Bosque, Brazos, Burleson, Camp, Cass, Cherokee, Cooke, Franklin, Freestone, Grayson, Gregg, Grimes, Harrison, Henderson, Hill, Hood, Hopkins, Hunt, Lee, Leon, Limestone, Madison, Marion, Morris, Nacogdoches, Navarro, Panola, Rains, Robertson, Rusk, Shelby, Smith, Somervell, Titus, Upshur, Van Zandt, Wise, and Wood Counties.

Section 117.3303, Exemptions

The proposed new §117.3303 would specify those stationary, reciprocating internal combustion engines that would be exempt from the requirements of Chapter 117, Subchapter E, Division 4. Engines with a hp rating less than 50 hp, diesel engines, and dual-fuel engines would be exempt from the proposed rule. Proposed §117.3303 would also exempt engines used: for research and testing; for performance verification and testing; solely to power other engines and gas-turbines during startups; exclusively for emergency situations, except for 52 hours of operation for testing and maintenance purposes; in response to and during any officially declared disaster or state of emergency; or directly and exclusively by the owner or operator for agricultural operations necessary for growing crops or raising of fowl or animals.

Section 117.3310, Emission Specifications for Eight-Hour Attainment Demonstration

The emission specifications for attainment demonstration, and additional requirements related to the emission specifications, are included in proposed new §117.3310. Proposed §117.3310(a) specifies the NO_x emission specifications for stationary gas-fired reciprocating internal combustion engines. Proposed new §117.3310(a)(1) establishes a 1.00 g/hp-hr NO_x emission specification for gas-fired rich-burn engines with a maximum rated capacity less than 500 hp. The NO_x emission specifications for gas-fired rich-burn engines with a maximum rated capacity equal to or greater than 500 hp are proposed in new §117.3310(a)(2) and include 0.60 g/hp-hr for engines fired on landfill gas and 0.50 g/hp-hr on all other gas-fired rich-burn engines. Emission specifications for gas-fired lean-burn engines are included in proposed new §117.3310(a)(3). Proposed new subsection (a)(3)(A) establishes a NO_x emission specification of 2.00 g/hp-hr for lean-burn engines placed into service before June 1, 2007. Proposed new subsection (a)(3)(B) establishes a NO_x emission specification of 1.50 g/hp-hr for lean-burn engines placed into service on or after June 1, 2007. The commission is proposing these specifications based on informal comments received during the stakeholder process and staff recommendations.

The commission estimates that approximately 850 stationary gas-fired engines would require combustion modifications or post-combustion control in order to meet these proposed emission specifications. NSCR technology is anticipated to be the primary control technology that would be used for rich-burn engines to meet the proposed emission specifications. Some engines with maximum rated capacities equal to or greater than 500 hp may have to install an additional catalyst module with the NSCR control package in order to comply with the more stringent 0.50 g/hp-hr emission specification. No landfill gas-fired rich-burn engines were identified in the counties impacted by this proposed rule. Should a landfill gas-fired rich-burn engine become subject to this proposed rule, the 0.60 g/hp-hr emission specification is consistent with the emission specifications for this category of engines in the Houston-Galveston-Brazoria ozone nonattainment area and is achievable through combustion modifications rather than installation of NSCR.

One possible control technology available for lean-burn engines is the application of an EGR kit (in order to reduce the excess O_2) combined with NSCR control. While NSCR is not normally applied to lean-burn engines, the use of the EGR kit reduces exhaust gas O_2 and allows NSCR to be installed. It is possible that owners or operators of some lean-burn engines may not be able to apply the EGR kit coupled with NSCR. In these instances, engine modifications identified by EPA as low-emission combustion (LEC) modifications are anticipated to be necessary to comply with the emission specifications. SCR is another possible control technology that may be applied to lean-burn engines to meet the emission specifications; however, because there are other technologies that can achieve equivalent reductions, SCR should not be necessary to achieve the proposed emission specifications.

A block one-hour averaging time for determining compliance with the NO_x emission specifications is specified in proposed new §117.3310(b). The block one-hour average must be calculated in the units of the applicable standard. Proposed new §117.3310(c) specifies that the maximum rated capacity used to determine the applicability of the emission specifications of §117.3310(a), or the exemption status of a unit under §117.3303(1), must be the greater of the maximum rated capacity as of December 31, 2000, or the maximum rated capacity after December 31, 2000.

Proposed new §117.3310(d) specifies that 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 stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, must be classified as a stationary gas-fired engine for the purposes of this proposed rule. Proposed new §117.3310(e) establishes emission specifications for CO and ammonia, and specifies that the owner or operator of any unit subject to the NO_x emission specifications of subsection (a), shall not allow the discharge into the atmosphere emissions in excess of the emission specifications in proposed new subsection (e)(1) or (2), except as provided in §117.3325 of this title. To prevent an ancillary increase in other emissions as a result of the implementation of this proposed NO_x control strategy, proposed new §117.3310(e)(1) includes emission specifications for CO. CO emissions are limited to 400 ppmv at 3.0% O_2 on a dry basis, or 3.0 g/hp-hr for stationary internal combustion engines. In addition, proposed new §117.3310(e)(1)(A) and (B) specify the averaging times for demonstrating compliance with the CO emission specification. Proposed new subparagraph (A) specifies a rolling 24-hour averaging period, for units equipped with CEMS or PEMS for CO, and proposed new subparagraph (B) specifies a one-hour average period, for units not equipped with CEMS or PEMS for CO. Proposed new §117.3310(e)(2) includes an ammonia emission specification for units that inject urea or ammonia into the exhaust stream for NO_x control. The proposed ammonia emission specifications are 10 ppmv at 15% O_2, dry basis, for gas-fired lean-burn engines, and 10 ppmv at 3.0% O_2, dry basis, for all others. The averaging times for these ammonia specifications are specified in proposed new §117.3310(e)(2)(A) and (B). Subparagraph (A) specifies a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia. Subparagraph (B) specifies a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia. Finally, proposed new §117.3310(f) specifies that an owner or operator may use emission reductions credits as specified in §117.9800 of this title to comply with the NO_x emission specifications of this section.

Section 117.3325, Alternative Case Specific Specifications

Proposed new §117.3325, Alternative Case Specific Specifications, sets forth provisions for alternative case emission specifications for CO and ammonia. Proposed §117.3325(a) specifies that the executive director may approve emission specifications different from the CO or ammonia specifications for a unit where a person can demonstrate that the affected unit cannot attain the CO or ammonia specifications of §117.3310(e). Proposed subsection (a)(1) specifies that the executive director shall consider on a case-by-case basis the technological and economic circumstances of the individual unit. Proposed subsection (a)(2) requires that the executive director must determine that such specifications are the result of the lowest emission specification the unit is capable of meeting after the application of controls to meet the NO_x emission specifications of §117.3310. Proposed subsection (a)(3) specifies that the executive director, in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through system-wide averaging at maximum capacity. Finally, proposed §117.3325(b) specifies that any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision, and that the requirements of §50.139 (relating to Motion to Overturn Executive Director's Decision) apply to §117.3325.

Section 117.3330, Operating Requirements

Operating requirements for units subject to the emission specifications of the division are listed in proposed new §117.3330. Proposed new §117.3330(a) specifies that the owner or operator shall operate any unit subject to the emission specifications in compliance with those specifications. Proposed new §117.3330(b) specifies that all units subject to the emission specifications 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. Proposed new §117.3330(b)(1) requires that 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. Proposed new §117.3330(b)(2) requires that each stationary internal combustion engine controlled with NSCR must be equipped with an automatic AFR controller that operates on exhaust O_2 or CO control and maintains the AFR in the range required to meet the engine's applicable emission specifications. Proposed new §117.3330(b)(3) requires that each stationary internal combustion engine must be checked for proper operation according to proposed new §117.8140(b). This testing includes recorded measurements of NO_x and CO emissions at least quarterly and as soon as practicable within two weeks after each occurrence of engine maintenance that may reasonably be expected to increase emissions, O_2 sensor replacement, catalyst cleaning, or catalyst replacement. Proposed new §117.8140(b) also specifies that stain tubes and portable NO_x analyzers are acceptable for this documentation. The quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours; however, this exemption does not apply to the requirement to test emissions after installation of controls, major repair work, or any time the owner or operator has reason to believe the emissions may have changed.

Section 117.3335, Monitoring, Notification, and Testing Requirements

Proposed new §117.3335 specifies the monitoring, notification, and testing requirements. Proposed new §117.3335(a) and (b) require that if the owner or operator installs a CEMS or PEMS to monitor O_2 or NO_x, the CEMS or PEMS must meet the requirements of proposed new §117.8100(a) or (b), as applicable. Proposed new §117.3335(c) specifies that if the owner or operator elects to install CEMS or PEMS, the installation and certification of the monitoring systems must be in accordance with the compliance schedule in §117.9340.

Proposed new §117.3335(d) lists the testing requirements of units subject to the emission specifications of §117.3310. Proposed §117.3335(d)(1) requires that each unit must be tested for NO_x, CO, and O_2 emissions and proposed subsection (d)(2) requires that each unit that injects urea or ammonia for NO_x control be tested for ammonia emissions. Proposed subsection (d)(3) requires that all testing be conducted according to proposed new §117.8000, which includes the general stack testing procedures and methods for Chapter 117. The specific requirements of proposed new §117.8000 are discussed later in this preamble. Proposed new §117.3335(d)(3) also specifies the owner or operator of a natural gas-fired engine may use ASTM D6522-00 to perform the NO_x, CO, and O_2 testing required in lieu of the methods specified in §117.8000. If ASTM D6522-00 is used, the test report must contain the information specified in proposed new §117.8010.

Proposed new subsection (d)(4) requires that test results must be reported in the units of the applicable emission limits and averaging periods. Proposed new §117.3335(d)(5) specifies that, for units equipped with CEMS or PEMS, the CEMS or PEMS must be installed and operational before testing under this subsection. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device. Proposed new §117.3335(d)(6) specifies that on units operating with CEMS or PEMS, initial compliance with the emission specifications of §117.3310 of this title may be demonstrated using the CEMS or PEMS, after monitor certification testing, in lieu of the methods specified in §117.3335(d)(3).

Proposed new §117.3335(d)(7) specifies retesting requirements for units not operating with CEMS or PEMS. Engines must be periodically tested according to proposed new §117.8140(a). The specific procedures and requirements in proposed new §117.8140(a) are discussed later in this preamble. In addition, proposed new §117.3335(d)(7)(A) requires retesting within 60 days after any modification that could reasonably be expected to increase the NO_x emission rate. Proposed new §117.3335(d)(7)(B) allows retesting at the discretion of the owner or operator after any modification that could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), FGR, and fuel-lean and conventional (fuel-rich) reburn. Proposed new §117.3335(d)(8) specifies that testing be performed in accordance with the schedule specified in §117.9340.

Proposed new §117.3335(e) requires that each unit that injects urea or ammonia into the exhaust stream for NO_x control must be monitored according to one of the ammonia monitoring procedures specified in proposed new §117.8130. These ammonia monitoring procedures include the use of the mass balance equation in §117.8130(1), the molybdenum oxidizer and NO_x analyzer approach in §117.8130(2), the use of stain tubes in §117.8130(3), or other methods approved by the executive director as allowed in §117.8130(4). Proposed new §117.3335(f) requires the owner or operator of an affected source to submit written notification of any CEMS or PEMS RATA or testing required under this section, except for any testing related to the ammonia monitoring specified in §117.3335(e), to the appropriate regional office and any local air pollution control agency having jurisdiction at least 15 days in advance of the date of RATA or testing.

Section 117.3345, Recordkeeping and Reporting Requirements

Proposed new §117.3345(a) requires that the owner or operator of a unit subject to the emission specifications of §117.3310 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 EPA, or local air pollution control agencies having jurisdiction. Proposed new §117.3345(a)(1) requires that records of hourly emissions be maintained for each unit using a CEMS or PEMS. Proposed new §117.3345(a)(2) specifies records for each stationary internal combustion engine subject to the emission specifications of §117.3310, including: emissions measurements required by §117.3330(b)(3); and catalytic converter, air-fuel ratio controller, or other emissions-related control system maintenance, including the date and nature of corrective actions taken. Proposed new subsection (a)(3) requires records of the CO measurements specified in §117.3330(b)(3). Proposed new subsection (a)(4) requires 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. Proposed new subsection (a)(5) requires the owner or operator to maintain records of the results of performance testing and proposed new subsection (a)(6) requires records of the ammonia monitoring required by §117.3335(e).

Proposed new §117.3345(b) specifies that written records of the number of hours of operation for each day's operation must be made for each engine claimed exempt under §117.3303(5) of this title or §117.3330(b)(3) of this title. Proposed new §117.3330(b)(3) references the engine testing provisions in proposed new §117.8140(b), which also includes an exemption for which proposed new §117.3345(b) would require written records. In addition, for each engine claimed exempt under §117.3303(5) of this title, written records must be maintained that reflect 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 of the emergency situation. The records must be maintained for at least five years and must be made available upon request to representatives of the executive director, the EPA, or any local air pollution control agency having jurisdiction.

Proposed new §117.3345(c) specifies that, except for the ammonia monitoring requirements of proposed §117.3335(e), the owner or operator of an affected unit must furnish the appropriate regional office and the Office of Compliance and Enforcement reports of all testing and monitor certification required under proposed new §117.3335. Reports must be submitted for review and approval within 60 days after completion of the testing and must contain the information specified in proposed new §117.8010.

SUBCHAPTER F, ACID MANUFACTURING

The commission proposes a new Chapter 117, Subchapter F, entitled Acid Manufacturing, that incorporates the divisions and associated rule language of the existing Chapter 117, Subchapter C, Acid Manufacturing.

DIVISION 1, ADIPIC ACID MANUFACTURING

The commission proposes a new Chapter 117, Subchapter F, Division 1, entitled Adipic Acid Manufacturing, that incorporates rule language from the existing Chapter 117, Subchapter C, Division 1, Adipic Acid Manufacturing.

Section 117.4000, Applicability

The commission proposes a new §117.4000 that incorporates the rule language from existing §117.301, concerning the applicability for adipic acid manufacturing.

Section 117.4005, Emission Specifications

The commission proposes a new §117.4005 that incorporates the rule language from existing §117.305 concerning the emission specifications for units subject to the Adipic Acid Manufacturing Division.

Section 117.4025, Alternative Case Specific Specifications

The commission proposes a new §117.4025 that incorporates the rule language from existing §117.321, concerning provisions for alternative case specific specifications for units that cannot attain the emission specifications in proposed new §117.4005.

Section 117.4035, Initial Demonstration of Compliance

The commission proposes a new §117.4035 that incorporates the rule language from existing §117.311, concerning initial demonstration of compliance for units subject to the emission specifications in proposed new §117.4005.

Section 117.4040, Continuous Demonstration of Compliance

The commission proposes a new §117.4040 that incorporates the rule language from existing §117.313, concerning continuous demonstration of compliance for units subject to the emission specifications in proposed new §117.4005. Proposed new §117.4040(a) - (e) incorporate the rule language from existing §117.313(a) - (e). In addition, for proposed new §117.4040(c), the reference to existing §117.213(f) is proposed to be changed to reference proposed new §117.8100(b). The requirements for PEMS in existing §117.213(f) are proposed to be incorporated in proposed new §117.8100(b).

Section 117.4045, Notification, Recordkeeping, and Reporting Requirements

The commission proposes a new §117.4045 that incorporates the rule language from existing §117.319, concerning notification, recordkeeping, and reporting requirements for affected facilities subject to the emission specifications in proposed new §117.4005.

Section 117.4050, Control Plan Procedures

The commission proposes a new §117.4050 that incorporates the rule language from existing §117.309, concerning the control plan procedures for persons affected by the division.

DIVISION 2, NITRIC ACID MANUFACTURING - OZONE NONATTAINMENT AREAS

The commission proposes a new Chapter 117, Subchapter F, Division 2, entitled Nitric Acid Manufacturing - Ozone Nonattainment Areas, that incorporates rule language from the existing Chapter 117, Subchapter C, Division 2, Nitric Acid Manufacturing - Ozone Nonattainment Areas.

Section 117.4100, Applicability

The commission proposes a new §117.4100 that incorporates the rule language from existing §117.401, concerning the applicability for nitric acid manufacturing in ozone nonattainment areas.

Section 117.4105, Emission Specifications

The commission proposes a new §117.4105 that incorporates the rule language from existing §117.405, concerning the emission specifications for affected nitric acid manufacturing units in ozone nonattainment areas.

Section 117.4125, Alternative Case Specific Specifications

The commission proposes a new §117.4125 that incorporates the rule language from existing §117.421, concerning provisions for alternative case specific specifications for units that cannot attain the emission specifications in proposed new §117.4105.

Section 117.4135, Initial Demonstration of Compliance

The commission proposes a new §117.4135 that incorporates the rule language from existing §117.411, concerning initial demonstration of compliance for units subject to the emission specifications in proposed new §117.4105.

Section 117.4140, Continuous Demonstration of Compliance

The commission proposes a new §117.4140 that incorporates the rule language from existing §117.413, concerning continuous demonstration of compliance for units subject to the emission specifications in proposed new §117.4105. Proposed new §117.4140(a) - (e) incorporate the rule language from existing §117.413(a) - (e). In addition, for proposed new §117.4140(c), the reference to existing §117.213(f) is proposed to be changed to reference proposed new §117.8100(b). The requirements for PEMS in existing §117.213(f) are proposed to be incorporated in proposed new §117.8100(b).

Section 117.4145, Notification, Recordkeeping, and Reporting Requirements

The commission proposes a new §117.4145 that incorporates the rule language from existing §117.419, concerning notification, recordkeeping, and reporting requirements for affected facilities subject to the emission specifications in proposed new §117.4105.

Section 117.4150, Control Plan Procedures

The commission proposes a new §117.4150 that incorporates the rule language from existing §117.409, concerning the control plan procedures for persons affected by the division.

DIVISION 3, NITRIC ACID MANUFACTURING - GENERAL

The commission proposes a new Chapter 117, Subchapter F, Division 3, entitled Nitric Acid Manufacturing - General, that incorporates rule language from the existing Chapter 117, Subchapter C, Division 3, Nitric Acid Manufacturing - General.

Section 117.4200, Applicability

The commission proposes a new §117.4200 that incorporates the rule language from existing §117.451, concerning the general applicability for nitric acid production units, except for units in applicable ozone nonattainment areas.

Section 117.4205, Emission Specifications

The commission proposes a new §117.4205 that incorporates the rule language from existing §117.455 concerning the emission specification for affected nitric acid production units.

Section 117.4210, Applicability of Federal New Source Performance Standards

The commission proposes a new §117.4210 that incorporates the rule language from existing §117.458, concerning the applicability of 40 CFR Part 60, Subpart G (Standards of Performance for Nitric Acid Plants).

SUBCHAPTER G, GENERAL MONITORING AND TESTING REQUIREMENTS

The commission proposes a new Chapter 117, Subchapter G that incorporates general monitoring and testing requirements from various divisions of Chapter 117 that are commonly cross-referenced from other divisions.

DIVISION 1, COMPLIANCE STACK TESTING AND REPORT REQUIREMENTS

Section 117.8000, Stack Testing Requirements

The commission proposes a new §117.8000, Stack Testing Requirements, that incorporates the common stack testing requirements from existing §117.211(e) and §117.479(e), concerning testing requirements for initial demonstration of compliance. Proposed new §117.8000(a) specifies that the requirements of proposed new §117.8000 are applicable when required by a provision of Chapter 117. When owners or operators are required to comply with §117.8000, the relevant section of Chapter 117 would reference proposed new §117.8000. Proposed new §117.8000(b) incorporates language from §117.479(e)(3) specifying that shorter test times may be used, if approved by the executive director. This provision is not included in existing §117.211(e), and incorporating the language in proposed new §117.8000(b) would ensure that the executive director has sufficient flexibility to consider allowing shorter test times, if warranted, whether the testing is conducted at sites that are minor or major sources of NO_x.

Proposed new §117.8000(c)(1) - (3), (5), and (6) incorporate the test method requirements from existing §117.211(e)(1) - (5). Also, proposed new §117.8000(c)(5) updates the section references to Test Method 1 and Performance Specification 2, because the EPA has reformatted the test methods and performance specifications from 40 CFR Part 60, Appendices A and B. The reference to §2.1 of Test Method 1 is proposed to be changed to §11.1, and the reference to §3.2 of Performance Specification 2 is proposed to be changed to §8.1.3. In addition, the commission proposes a new §117.8000(c)(4) to specify that, for units that inject ammonia or urea to control NO_x emissions, the methods required to determine ammonia are the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method 27. The initial demonstration of compliance requirements from existing §117.211 require ammonia testing on units that inject urea or ammonia for NO_x control; however, existing §117.211 does not specify methods for conducting the ammonia testing. The methods in proposed new §117.8000(c)(4) are the same methods required to determine the correction factor "d" from the mass balance equation approach of monitoring for ammonia slip in existing §117.114 and §117.214. The commission is soliciting comments specifically regarding including the specified ammonia test methods in proposed new §117.8000(c)(4).

Finally, proposed new §117.8000(d) incorporates the language from existing §117.211(e)(6), concerning the provisions for EPA-approved alternative test methods and minor modifications to test methods.

Section 117.8010, Compliance Stack Test Reports

The commission proposes a new §117.8010, Compliance Stack Test Reports, that incorporates the compliance stack test report content requirements from existing §117.211(g) that was commonly referenced from other divisions. Proposed new §117.8010 specifies that the requirements of proposed new §117.8010 are applicable when required by a provision of Chapter 117. When owners or operators are required to comply with §117.8010, the relevant section of Chapter 117 would reference proposed new §117.8010. The report content requirements from existing §117.211(g)(1) - (8) are incorporated in proposed new §117.8010(1) - (8). Also, proposed new §117.8010(8)(B) updates the section reference to Performance Specification 2, because the EPA has reformatted the test methods and performance specifications from 40 CFR Part 60, Appendices A and B. The reference to §9 of Performance Specification 2 is proposed to be changed to §8.5.

DIVISION 2, EMISSION MONITORING

The commission proposes a new Chapter 117, Subchapter G, Division 2, Emission Monitoring, that incorporates general monitoring requirements from various divisions of Chapter 117 that are commonly cross-referenced from other divisions.

Section 117.8100, Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources

The commission proposes a new §117.8100, that incorporates the general requirements from existing §117.213(e) and (f) for CEMS and PEMS used at industrial, commercial, and institutional sources to comply with a monitoring requirement of Chapter 117. Proposed new §117.8100(a) specifies that the requirements for CEMS in proposed new §117.8100(a) are applicable when required by a provision of Chapter 117. When owners or operators are required to comply with §117.8100(a), the relevant section of Chapter 117 would reference proposed new §117.8100. The requirements for CEMS in existing §117.213(e)(1) - (3), (5), and (6) are proposed to be incorporated in proposed new §117.8100(a)(1) - (6). Existing §117.213(e)(4) includes CEMS requirements specific to the Houston-Galveston-Brazoria ozone nonattainment area and is not proposed to be included in proposed new §117.8100(a).

Proposed new §117.8100(b) specifies that the requirements for PEMS in proposed new §117.8100(b) are applicable when required by a provision of Chapter 117. When owners or operators are required to comply with §117.8100(b), the relevant section of Chapter 117 would reference proposed new §117.8100. The requirements for PEMS in existing §117.213(f)(2) - (7) are proposed to be incorporated in proposed new §117.8100(b)(1) - (6). Existing §117.213(f)(1) specifies that the PEMS must predict the pollutant emissions in the units of the applicable emission specifications of the division, and is not proposed to be incorporated in proposed new §117.8100(b) because division-specific requirements might apply.

The commission proposes a new §117.8100(c) that specifies that reports of any RATA performed in accordance with §117.8100 must comply with the proposed new §117.8010, concerning compliance stack test report contents. Proposed new §117.8100(c) is necessary to clarify that the report for any RATA performed in accordance with §117.8100(a) or (b) must still meet the report content requirements.

Section 117.8110, Emission Monitoring System Requirements for Utility Electric Generation Sources

The commission proposes a new §117.8110, that incorporates the general requirements from existing §117.113(c) and (f) for CEMS and PEMS used at utility electric generation sources to comply with a monitoring requirement of Chapter 117. The requirements for CEMS and PEMS at utility electric generation sources in existing §117.113(c) and (f) are sufficiently different from the requirements for industrial, commercial, and institutional sources in existing §117.213 that combining the requirements for both source categories would result in significant substantive changes impacting owners and operators. Therefore, the commission has proposed to maintain the monitoring system requirements for CEMS and PEMS at a utility electric generation source separate from other source categories. Proposed new §117.8110(a) specifies that the requirements for

CEMS in proposed new §117.8110(a) are applicable when required by a provision of Chapter 117. When owners or operators are required to comply with §117.8110(a), the relevant section of Chapter 117 would reference proposed new §117.8110. The requirements for CEMS in existing §117.113(c)(1) and (2) are proposed to be incorporated in proposed new §117.8110(a)(1) and (2). Existing §117.113(c)(3) is a Houston-Galveston-Brazoria ozone nonattainment area specific requirement for CEMS and is not proposed to be incorporated into §117.8110(a).

Proposed new §117.8110(b) specifies that the requirements for PEMS in proposed new §117.8110(b) are applicable when required by a provision of Chapter 117. When owners or operators are required to comply with §117.8110(b), the relevant section of Chapter 117 would reference proposed new §117.8110. The requirements for PEMS in existing §117.113(f)(2) - (4) are proposed to be incorporated in proposed new §117.8110(b)(1) - (3). Existing §117.113(f)(1) specifies that the PEMS must predict the pollutant emissions in the units of the applicable emission specifications of the division, and is not proposed to be incorporated in proposed new §117.8110(b) because division-specific requirements might apply. In addition, the reference in existing §117.113(f)(4)(B) to existing §117.213(f) is proposed to be changed to §117.8100(b), because the applicable requirements from §117.213(f) are proposed to be incorporated in new §117.8100(b).

Section 117.8120, Carbon Monoxide (CO) Monitoring

The commission proposes a new §117.8120, that incorporates the CO monitoring requirements from existing §117.113(b) and §117.213(d), and the optional CO monitoring requirements from existing §117.143(b). Proposed new §117.8120 specifies that the requirements for CO monitoring in proposed new §117.8120 are applicable when required by a provision of Chapter 117. When owners or operators are required to comply with §117.8120, the relevant section of Chapter 117 would reference proposed new §117.8120. The references to applicable subsections for CEMS or PEMS used to monitor CO in existing §§117.113(b)(1), 117.143(b)(1), and 117.213(b)(1) are proposed to be changed to proposed new §117.8100(a) or §117.8110(a) and §117.8100(b) or §117.8110(b), as applicable.

Section 117.8130, Ammonia Monitoring

The commission proposes a new §117.8130, that incorporates the ammonia monitoring requirements from existing §117.114(a)(4) and §117.214(a)(1)(D) that are commonly referenced from various divisions of Chapter 117. Proposed new §117.8130 specifies that the requirements for ammonia monitoring in proposed new §117.8130 are applicable when required by a provision of Chapter 117. When owners or operators are required to comply with §117.8130, the relevant section of Chapter 117 would reference proposed new §117.8130. Existing §117.114(a)(4)(A) - (D) and §117.214(a)(1)(D)(i) - (iv) are incorporated in proposed new §117.8030(1) - (4). The O_2 correction for ammonia concentrations to 3.0% for boilers and 15% gas turbines in the equation in existing §117.114(a)(4)(A) is identical to the O_2 corrections for boilers and gas turbines in existing §117.214(a)(1)(D)(i); therefore, proposed new §117.8030(1) incorporates the O_2 correction criteria for the ammonia concentrations from §117.214(a)(1)(D)(i). The methods specified for variable "d" of the equations in §117.114(a)(4)(A) and §117.214(a)(1)(D)(i) are identical and are proposed to be incorporated in proposed new §117.8000(c)(4). Variable "d" of the equation in proposed new §117.8130(1) is proposed to specify that the correction factor is the ratio of measured slip to calculated ammonia slip, where the measured slip is obtained from the stack sampling for ammonia during an initial demonstration of compliance required by Chapter 117 and using the methods specified in proposed new §117.8000.

Section 117.8140, Emission Monitoring for Engines

The commission proposes a new §117.8140, that incorporates certain testing requirements for stationary internal combustion engines from existing §§117.208(d)(7), 117.213(g)(1), 117.214(b)(2), and 117.478(b)(5). Proposed new §117.8140(a), concerning periodic testing for engines, specifies that the requirements in proposed new §117.8140(a) are applicable when required by a provision of Chapter 117. When owners or operators are required to comply with §117.8140(a), the relevant section of Chapter 117 would reference proposed new §117.8140(a). Proposed new §117.8140(a)(1) - (3) incorporate the engine testing provisions for NO_x and CO from §117.213(g)(1)(A) - (C). Proposed new §117.8140(a)(1) specifies that the methods in proposed new §117.8000 must be used. The provisions for testing on a biennial calendar basis or with 15,000 hours of operation in existing §117.213(g)(1)(B) are incorporated in proposed new §117.8140(a)(2). The exemption from periodic testing in existing §117.213(g)(1)(C) for engines used exclusively in emergency situations is incorporated in proposed new §117.8140(a)(3).

Proposed new §117.8140(b), concerning checks for proper operation of engines, specifies that the requirements in proposed new §117.8140(a) are applicable when required by a provision of Chapter 117. Proposed new §117.8140(b) incorporates the engine-testing provisions for proper operation from §§117.208(d)(7), 117.214(b)(2)(A), and 117.478(b)(5). The exemption from quarterly testing for engines with a monthly run time of 10 hours or less in existing §117.214(b)(2)(A) and §117.478(b)(5) is only applicable in the Houston-Galveston-Brazoria ozone nonattainment area. This exemption is not in §117.208(d)(7). The commission is proposing to incorporate the exemption for engines with a monthly run time of 10 hours or less in proposed new §117.8140(b), expanding the applicability of the exemption to affected engines in the Beaumont-Port Arthur and Dallas-Fort Worth ozone nonattainment areas. The provision in existing §117.214(b)(2)(A) and §117.478(b)(5) that specifies the exemption does not diminish the requirement to test emissions after installation of controls, major repair work, or any time the owner or operator believes emissions may have changed is also proposed to be incorporated in proposed new §117.8140(b).

SUBCHAPTER H, ADMINISTRATIVE PROVISIONS

The commission proposes a new Chapter 117, Subchapter H, entitled Administrative Provisions, that incorporates the administrative provisions from existing Chapter 117, Subchapter E, concerning compliance schedules and certain compliance flexibility provisions, and includes new compliance schedules and changes to reflect new proposed rules for the Dallas-Fort Worth eight-hour ozone attainment demonstration.

DIVISION 1, COMPLIANCE SCHEDULES

The commission proposes a new Chapter 117, Subchapter H, Division 1, entitled Compliance Schedules, that incorporates the compliance schedules from existing Chapter 117, Subchapter E, §§117.510, 117.512, 117.520, 117.524, 117.530, and 117.534, and includes new compliance schedules and changes to reflect new proposed rules for the Dallas-Fort Worth eight-hour ozone attainment demonstration.

Section 117.9000, Compliance Schedule for Beaumont-Port Arthur Ozone Nonattainment Area Major Sources

The commission proposes a new §117.9000 that incorporates the compliance schedule rule language from existing §117.520(a), applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.9000(1) incorporates the rule language from existing §117.520(a)(1), concerning the compliance schedule for RACT requirements. Proposed new §117.9000(2) incorporates the rule language from existing §117.520(a)(2), concerning the compliance schedule for lean-burn engine requirements, and proposed new §117.9000(3) incorporates the rule language from existing §117.520(a)(3), concerning the compliance schedule for requirements associated with the emission specifications for attainment demonstration. In addition, as previously indicated in this preamble, the commission is proposing to incorporate general requirements from existing §117.213 for CEMS and PEMS at industrial, commercial, and institutional sources in a new §117.8100. Therefore, for proposed new §117.9000(1)(B)(i) and (3)(B)(iii), the commission proposes to change the reference for the CEMS or PEMS performance evaluation and quality assurance procedures from existing §117.213(e)(1)(A) and (B) and (f)(3) - (5)(A) to the proposed new §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A). Also, existing §117.520(a)(3)(C)(ii) incorrectly references to semiannual reports required by existing §117.213(c)(1)(C). Existing §117.213(c)(1)(C) does not include a requirement for semiannual reports. Therefore, the commission proposes to exclude this cross-reference from the proposed new §117.9000(3)(C)(ii).

Section 117.9010, Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Major Sources

The commission proposes a new §117.9010 that incorporates the compliance schedule rule language from existing §117.520(b), applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.9010(1) incorporates the rule language from existing §117.520(b)(1)(A). Proposed new §117.9010(2) incorporates the rule language from existing §117.520(b)(1)(B). As previously indicated in this preamble, the commission is proposing to incorporate general requirements from existing §117.213 for CEMS and PEMS at industrial, commercial, and institutional sources in a new §117.8100. Therefore, for proposed new §117.9010, the commission proposes to change the reference for the CEMS or PEMS performance evaluation and quality assurance procedures from existing §117.213(e)(1)(A) and (B) and (f)(3) - (5)(A) to the proposed new §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A).

In addition, the compliance schedule in existing §117.520(b)(2), for engines subject to existing §117.206(b)(3), is proposed to be incorporated in proposed new §117.9030, concerning the compliance schedule for the Dallas-Fort Worth eight-hour ozone nonattainment area. The applicability for existing §117.520(b)(2) is the nine-county area of the Dallas-Fort Worth eight-hour ozone nonattainment area and proposed new §117.9030 is the most appropriate location to incorporate these requirements.

Section 117.9020, Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources

The commission proposes a new §117.9020 that incorporates the compliance schedule rule language from existing §117.520(c), applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.9020(1) incorporates the rule language from existing §117.520(c)(1), concerning the compliance schedule for RACT requirements. Proposed new §117.9020(2) incorporates the rule language from existing §117.520(c)(2), concerning the compliance schedule for requirements associated with the emission specifications for attainment demonstration. In addition, as previously indicated in this preamble, the commission is proposing to incorporate general requirements from existing §117.213 for CEMS and PEMS at industrial, commercial, and institutional sources in a new §117.8100. Therefore, for proposed new §117.9020, the commission proposes to change the reference for the CEMS or PEMS performance evaluation and quality assurance procedures from existing §117.213(e)(1)(A) and (B) and (f)(3) - (5)(A) to the proposed new §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A).

Finally, for proposed new §117.9020(2)(B)(ii), the commission proposes to revise the compliance schedule language in existing §117.520(c)(2)(B)(ii) regarding submitting the certification of activity level for electric generating facilities subject to the system cap in existing §117.210. The current language in existing §117.520(c)(2)(B)(ii) might be incorrectly interpreted that an owner or operator is required to use the first two consecutive third quarters of actual activity level data out of the first five years of operation. The commission's intent in existing §117.210 and §117.520(c)(2)(B)(ii) is that the owner or operator may select any two consecutive third quarters of actual level of activity data out of the first five years of operation, and that the selection must be made no later than 60 days after the end of the first five years of operation. Therefore, the language in proposed new §117.9020(2)(B)(ii) is revised to specify this requirement more accurately.

Section 117.9030, Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources

The commission proposes a new §117.9030, Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources, that specifies the compliance schedules for units subject to the emissions specifications of §117.410 and §117.423.

Proposed new §117.9030(a) specifies the compliance schedule for any stationary, reciprocating, internal combustion engines subject to the emission specifications of §117.410(a), and incorporates the existing compliance schedule rule language from existing §117.520(b)(2). Proposed new §117.9030(a)(1) incorporates the rule language from existing §117.520(b)(2)(A). Proposed new §117.9030(a)(2) and (a)(2)(A) - (D) incorporate the rule language from existing §117.520(b)(2)(B) and (B)(i) - (iv).

In addition, for proposed new §117.9030(a)(1)(C), the commission is proposing to revise the requirement in existing §117.520(b)(2)(B)(iii) to submit final control plans required by existing §117.215. As previously indicated in this preamble, the commission is proposing to incorporate the requirements for engines subject to existing §117.206(b)(3) and §117.520(b)(2) in the proposed new division for the Dallas-Fort Worth eight-hour ozone nonattainment area. Existing §117.520(b)(2)(B)(iii) incorrectly references the final control plan procedures for RACT. The correct cross-reference for final control plans for engines subject to existing §117.206(b)(3) should be existing §117.216, Final Control Plan Procedures for Attainment Demonstration Emission Specifications. Therefore, the applicable final control plan procedures for attainment demonstration emission specifications for the engines under proposed new Subchapter B, Division 3 are in proposed new §117.454. Because this proposed change could result in a change in the information required, the commission is proposing to change the compliance date in proposed new §117.9030(a)(1)(C) for submitting the final control plans to January 1, 2008. The commission is soliciting comment on this specific change to the final control plan requirements for engines subject to existing §117.206(b)(3) and §117.520(b)(2). The commission is not proposing to change, nor accepting comment on, any other existing compliance schedule requirements from existing §117.520(b)(2).

Proposed new §117.9030(b) specifies the compliance schedule requirements for units subject to the emissions specifications of §117.410(b). Proposed new §117.9030(b)(1) requires the owner or operator of any stationary source of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area that is a major source of NO_x and is subject to §117.410(b) to submit the initial control plan required by §117.450 of this title no later than June 1, 2008, and to comply with all other requirements of Subchapter B, Division 4 as soon as practicable, but no later than March 1, 2009.

Proposed new §117.9030(b)(2) specifies the owner or operator of any stationary source of NO_x that becomes subject to the requirements of Subchapter B, Division 4 of this chapter on or after March 1, 2009, shall comply with the requirements of Subchapter B, Division 4 as soon as practicable, but no later than 60 days after becoming subject. For example, new units placed into service after March 1, 2009, would be required to comply within 60 days after startup of the unit. Existing units previously exempt from the rule, but no longer qualifying for that exemption after March 1, 2009, would be required to comply with the proposed rule no later that 60 days after the date that the exemption status was lost.

Section 117.9100, Compliance Schedule for Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources

The commission proposes a new §117.9100 that incorporates the compliance schedule rule language from existing §117.510(a), applicable to the Beaumont-Port Arthur ozone nonattainment area. Proposed new §117.9100(1) incorporates the rule language from existing §117.510(a)(1), concerning the compliance schedule for RACT requirements. Proposed new §117.9100(2) incorporates the rule language from existing §117.510(a)(2), concerning the compliance schedule for requirements associated with the emission specifications for attainment demonstration.

Section 117.9110, Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources

The commission proposes a new §117.9110 that incorporates the compliance schedule rule language from existing §117.510(b), applicable to the Dallas-Fort Worth ozone nonattainment area. Proposed new §117.9110(1) incorporates the rule language from existing §117.510(b)(1), concerning the compliance schedule for RACT requirements. Proposed new §117.9110(2) incorporates the rule language from existing §117.510(b)(2), concerning the compliance schedule for requirements associated with the emission specifications for attainment demonstration.

Section 117.9120, Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources

The commission proposes a new §117.9120 that incorporates the compliance schedule rule language from existing §117.510(c), applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.9120(1) incorporates the rule language from existing §117.510(c)(1), concerning the compliance schedule for RACT requirements. Proposed new §117.9120(2) incorporates the rule language from existing §117.510(c)(2), concerning the compliance schedule for requirements associated with the emission specifications for attainment demonstration.

Section 117.9130, Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources

The commission proposes a new §117.9130, Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources, that specifies the compliance schedule for owners or operators subject to the proposed new Subchapter C, Division 4. Proposed new §117.9130(a) specifies the compliance schedule for existing units subject to the proposed rule. Proposed new §117.9130(a)(1) requires the owner or operator to submit the initial control plan required by proposed new §117.1350 by no later than June 1, 2008. Proposed new §117.9130(a)(2) specifies that the owner or operator must comply with all other requirements of proposed new Subchapter C, Division 4 as soon as practicable, but no later that March 1, 2009. Finally, the commission proposes a new §117.9130(b) that specifies, for units in the Dallas-Fort Worth eight-hour ozone nonattainment area that become subject to proposed new Subchapter C, Division 4 on or after March 1, 2009, the owner or operator must comply as soon as practicable, but no later than 60 days after becoming subject.

Section 117.9200, Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Minor Sources

The commission proposes a new §117.9200 that incorporates the compliance schedule rule language from existing §117.534, concerning the compliance schedule for boilers, process heaters, and stationary engines and gas turbines at minor sources, applicable to the Houston-Galveston-Brazoria ozone nonattainment area. Proposed new §117.9200(1) incorporates the rule language from existing §117.534(1), concerning the compliance schedule for sources subject to the Mass Emission Cap and Trade Program. Proposed new §117.9200(2) incorporates the rule language from existing §117.534(2), concerning the compliance schedule for sources not subject to the Mass Emission Cap and Trade Program. In addition, as previously indicated in this preamble, the commission is proposing to incorporate general requirements from existing §117.213 for CEMS and PEMS at industrial, commercial, and institutional sources in a new §117.8100. Therefore, for proposed new §117.9200, the commission proposes to change the reference for the CEMS or PEMS performance evaluation and quality assurance procedures from existing §117.213(e)(1)(A) and (B) and (f)(3) - (5)(A) to the proposed new §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A).

Section 117.9210, Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources

Proposed new §117.9210 specifies the compliance schedule for sources subject to the proposed new Subchapter D, Division 2, Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources. Proposed new §117.9210(a) specifies the owner or operator of each stationary source of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area that is not a major source of NO_x shall comply with the requirements of Subchapter D, Division 2 as soon as practicable, but no later than March 1, 2009. Proposed new §117.9210(b) specifies the owner or operator of any stationary source of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area that becomes subject to the requirements of Subchapter D, Division 2 on or after March 1, 2009, must comply with the requirements of Subchapter D, Division 2 as soon as practicable, but no later than 60 days after becoming subject.

Section 117.9300, Compliance Schedule for Utility Electric Generation in East and Central Texas

The commission proposes a new §117.9300 that incorporates the compliance schedule rule language from existing §117.512, concerning the compliance schedule for utility electric generation in East and Central Texas. Proposed new §117.9300(1) incorporates the rule language from existing §117.512(1), and proposed new §117.9300(2) incorporates the rule language from existing §117.512(2).

Section §117.9320, Compliance Schedule for Cement Kilns

The commission is proposing a new §117.9320 that incorporates the rule language regarding the compliance schedule for cement kilns from existing §117.524. Proposed new §117.9320(a) and (b) incorporate the rule language from existing §117.524(a) and (b), respectively. In addition, for proposed new §117.9320(a), the commission proposes to add the language "Except as specified in subsection (c) of this section . . .." This change is necessary to clarify that the compliance schedule in subsection (a) is not applicable to the new proposed requirements in §§117.3123, 117.3142, and 117.3145.

A new §117.9320(c) is proposed to specify that the owner or operator of each portland cement kiln in Ellis County must be in compliance with the requirements of §117.3123 and §117.3142, and the applicable requirements of §117.3145 as soon as practicable, but no later than March 1, 2009. In addition, proposed new §117.9320(c) specifies that the provisions in proposed new §117.9320(b), regarding extension of compliance schedules, do not apply to subsection (c) or the requirements of §117.3123, §117.3142, or the applicable requirements of §117.3145. Proposed new §117.9320(c) is necessary to ensure that the required reductions under the source cap of proposed §117.3123 occur by the date necessary to demonstrate attainment.

Section 117.9340, Compliance Schedule for East Texas Combustion

The commission proposes a new §117.9340 to specify the compliance schedule for owner or operators to comply with the requirements of Chapter 117, Subchapter E, Division 4, East Texas Combustion. Proposed §117.9340(a) specifies that the owner or operator of each stationary, reciprocating internal combustion engine subject to Subchapter E, Division 4 must comply with the requirements of Subchapter E, Division 4 as soon as practicable, but no later than March 1, 2009. Proposed §117.9340(b) specifies that the owner or operator of a stationary, reciprocating internal combustion engine that becomes subject to the requirements of Subchapter E, Division 4 on or after March 1, 2009, must comply with the requirements of that division as soon as practicable, but no later than 60 days after becoming subject.

Section 117.9500, Compliance Schedule for Nitric Acid and Adipic Acid Manufacturing Sources

The commission proposes a new §117.9500 that incorporates the compliance schedule rule language from existing §117.530, concerning the compliance schedule for nitric acid and adipic acid manufacturing sources. Proposed new §117.9300(1) - (3) incorporate the rule language from existing §117.530(1) - (3), respectively.

DIVISION 2, COMPLIANCE FLEXIBILITY

The commission proposes a new Chapter 117, Subchapter H, Division 2, entitled Compliance Flexibility, that incorporates the rule language from existing Chapter 117, §117.570 and §117.571, and includes changes to reflect new proposed rules for the Dallas-Fort Worth eight-hour ozone attainment demonstration.

Section 117.9800, Use of Emission Credits for Compliance

The commission proposes a new §117.9800 that incorporates the rule language from existing §117.570, concerning the use of emission credits for compliance. Proposed new §117.9800(a) - (d) incorporate the rule language from existing §117.570(a) - (d), respectively. In addition, proposed new §117.9800(a) is restructured for clarity. The list of applicable sections in existing §117.570(a) is proposed to be listed as separate paragraphs in proposed new §117.9800(a)(1) - (8). Applicable section number references for the new proposed rules for the Dallas-Fort Worth eight-hour ozone attainment demonstration are included in proposed new §117.9800(a)(5), (7), and (8). Also, for proposed new §117.9800(d), the list of applicable sections in existing §117.570(d), concerning final control plans, is also proposed to be revised to include proposed new §117.456 and §117.1356.

Section 117.9810, Use of Emission Reductions Generated from the Texas Emissions Reduction Plan (TERP)

The commission proposes a new §117.9810 that incorporates the rule language from existing §117.571, concerning the use of emission reductions generated from the Texas Emissions Reduction Plan. Proposed new §117.9810(a) and (b) incorporate, and restructure for clarity, the rule language from existing §117.571(a). Proposed new §117.9810(a) revises the applicability of §117.571 to include the Dallas-Fort Worth eight-hour ozone nonattainment area. The list of applicable sections in existing §117.571(a) is proposed to be listed as separate paragraphs in proposed new §117.9810(a)(1) - (6). Applicable section number references for the new proposed rules for the Dallas-Fort Worth eight-hour ozone attainment demonstration are included in proposed new §117.9810(a)(6). The rule language concerning provisions for obtaining emission reductions generated from TERP in existing §117.571(a)(1) - (6) is proposed to be incorporated in new §117.9810(b) and (b)(1) - (6). Also, for proposed new §117.9810(b)(6), the commission proposes to remove the language "of this division" regarding applicable emission reduction requirements, because this reference has no meaning under the proposed new format for the division that incorporates this rule language. The proposed new §117.9810(b)(6) specifies "applicable emission reduction requirements of this chapter." Finally, proposed new §117.9810(c) incorporates the rule language from existing §117.571(b).

FISCAL NOTE: COSTS TO STATE AND LOCAL GOVERNMENT

Nina Chamness, Analyst, Strategic Planning and Assessment Section, has determined that, for the first five-year period the proposed rules are in effect, no significant fiscal implications are anticipated for the agency. However, the proposed rules may increase the workload for some agency staff. The proposed rules would have fiscal implications, some of which may be significant for other state agencies, units of local governments and federal entities in the Dallas-Fort Worth eight-hour ozone nonattainment area or in northeast Texas if they own or operate sources of NO_x emissions. The proposed rules may cost all governmental entities as much as $9.6 million to comply with the major NO_x source requirements and the minor NO_x source requirements during the first five years they are in effect. Industry would also experience fiscal implications, which could be significant depending on the entity and the controls required. Total capital, testing, and fuel meter costs for all industries in the areas affected by the proposed rules could range from $255 million to $350.6 million for the first five years the rules are in effect.

The proposed rules would repeal and reformat the existing version of Chapter 117 to provide greater clarity and ease of use, provide space for future rulemaking activities, and retain current one-hour ozone rules for all ozone attainment and nonattainment areas of the state. The proposed rules also provide for the Dallas-Fort Worth eight-hour ozone attainment demonstration as required by EPA and propose to reduce NO_x emissions from certain sources in northeast Texas. Finally, the proposed rules would also implement provisions of HB 965, 79th Legislature, 2005.

The proposed rules apply to many areas and sources of NO_x in Texas and are intended to become part of the SIP. Some of the proposed rules may have significant fiscal implications for some governmental entities and industry in the Dallas-Fort Worth eight-hour ozone nonattainment area. This area includes nine counties, specifically Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant. Certain northeast Texas counties would also be affected by parts of the proposed rules that would reduce NO_x emissions from stationary, gas-fired reciprocating, internal combustion engines. These counties are Anderson, Bosque, Brazos, Burleson, Camp, Cass, Cherokee, Cooke, Franklin, Freestone, Grayson, Gregg, Grimes, Harrison, Henderson, Hill, Hood, Hopkins, Hunt, Lee, Leon, Limestone, Madison, Marion, Morris, Nacogdoches, Navarro, Panola, Rains, Robertson, Rusk, Shelby, Smith, Somervell, Titus, Upshur, Van Zandt, Wise, and Wood. These proposed rules can be found in: Subchapter B, Division 4; Subchapter C, Division 4; Subchapter D, Division 2; and Subchapter E, Divisions 2, 3, and 4.

The fiscal implications of the proposed rules for governmental entities are summarized as follows:

CHAPTER 117 REFORMAT

The reformatting under the proposed rules should make it easier for affected owners or operators in all designated nonattainment areas (Houston-Galveston-Brazoria, Beaumont-Port Arthur, and Dallas-Fort Worth) to find rules that apply specifically to their respective areas. Any minor clarifications and corrections under the proposed rules are not anticipated to have any fiscal implications for any governmental entities or industry. One proposed change would allow an additional option for providing substitute data to the agency when NO_x monitors are down. Owners or operators of major sources of NO_x in the Houston-Galveston-Brazoria nonattainment area that voluntarily choose this option may have to pay for reprogramming of their emission monitoring system and data acquisition and handling system. Costs of this possible reprogramming are dependent on a number of variables unique to the owner/operator. As such, staff cannot estimate the cost of this voluntary option, although it is not anticipated to be significant.

SUBCHAPTER B, DIVISION 4: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MAJOR SOURCES

This section of the proposed rules would require owners/operators of major sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area to reduce NO_x emissions by March 1, 2009, from industrial, commercial, or institutional (ICI) boilers and gas turbines; duct burners used in turbine exhaust ducts; process heaters and furnaces; stationary internal combustion engines; brick, ceramic and lime kilns; metallurgical heat treating and reheat furnaces; electric arc furnaces used in steel production; lead smelting blast (cupola) and reverberatory furnaces; glass melting furnaces, fiberglass and mineral wool fiber melting furnaces, fiberglass and wool fiber curing and forming ovens; heaters and ovens, and dryers used in organic solvent, printing ink, and ceramic tile, clay, and brick drying, and calcining and vitrifying; and incinerators. The proposed emission specifications for these source categories are consistent with current emission specifications effective in the Houston-Galveston-Brazoria ozone nonattainment area.

Governmental entities that own or operate the previously mentioned units would experience fiscal implications, some of which may be significant, under the proposed rules. Most fiscal implications for governmental entities would result from the proposed rules for major sources of NO_x emissions as well as proposed rules for minor sources of NO_x emissions.

As many as five ICI boilers and one dual-fuel engine at two state-supported medical centers; eight boilers at three federal institutions; and one boiler and two dual-fuel engines at two local governments may be required to implement emission controls under the proposed rules for major NO_x sources. Estimates for capital costs, CEMS, compliance testing, and fuel meters could be as much as $3.3 million for state medical centers in the Dallas-Fort Worth eight-hour ozone nonattainment area to retrofit five ICI boilers and one dual-fuel engine in the first year the proposed rules are in effect. Federal entities could spend as much as $704,000 for eight boilers, and local governments could spend as much as $1 million to retrofit one ICI boiler and two dual-fuel engines. Costs to retrofit major NO_x sources owned by governmental entities could total $5 million area wide. Annual costs for all governmental entities in the area are estimated to be $2.9 million. Cost-effectiveness for the proposed emission reduction is approximately $3,800 to $5,700 per ton of NO_x reduced.

The cost estimates that follow are used to project the fiscal implications of controls and other required monitoring and testing for both governmental and industrial major and minor NO_x sources in the Dallas-Fort Worth eight-hour ozone nonattainment area.

Capital costs for emission controls vary depending on the size of the unit and the control technology selected. Emission control options for ICI boilers could include installation of SCR and low-NO_x burners. Emission control options for rich-burn engines could include NSCR and secondary catalyst retrofits. Emission control options for lean-burn engines could include installation of EGR kits combined with the use of NSCR or installation of SCR. Emission controls for dual-fuel engines would probably require SCR installation.

Estimates for SCR installation costs for boilers range from $4,000 to $6,000 per MMBtu/hr, and low-NO_x burner installation costs for boilers are approximately $3,100 per MMBtu/hr.

Annual costs are estimated to be $700 per MMBtu/hr for SCR controls and $600 per MMBtu/hr for low-NO_x burners.

Installation of NSCR to meet the 0.50 g/hp-hr standard of the proposed rules for rich-burn engines is estimated to cost $16,667 plus $16.67 per hp of the engine. Cost of a secondary catalyst, if needed, is approximately $15 per hp. For lean-burn engines, installation of an EGR kit plus NSCR can cost $39,167 plus $41.67 per hp, plus an additional $15 per hp if a secondary NSCR catalyst is required. If SCR is required to meet the proposed emission limits for lean-burn engines, installation can cost $310,000 plus $72.70 per hp. Annual costs for NSCR and secondary catalyst would be approximately $2,600 plus $11 per hp for NSCR and $5.00 per hp for the catalyst for either rich-burn or lean-burn engines. Annual costs for SCR would be approximately $37,300 plus $16.30 per hp. Installation of SCR for dual-fuel engines is estimated to cost $187,000 plus $98 per hp. The annual costs for SCR installed on a dual-fuel engine would be the same as annual costs associated with SCR installed on a lean-burn engine.

Installation of emission controls could also require installation of CEMS equipment, periodic testing, quarterly testing, and fuel meter installation. Capital costs for installation of CEMS are estimated to be $148,300 per unit. Fuel meters are estimated to cost $2,500 per meter, and initial compliance tests are estimated to cost $3,500. Quarterly tests are estimated to cost $100 per test.

SUBCHAPTER C, DIVISION 4: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

Governmental entities that own or operate utility boilers, auxiliary steam boilers, and stationary gas turbines at electric generating facilities (EGFs) would be required to limit NO_x emissions to the appropriate emission specifications for each unit type under the proposed rules. Governmental entities owning or operating EGFs may already be in compliance with the proposed emission specifications, have the capability to meet the specifications with existing control technologies, or could utilize a megawatt-hour output based efficiency option to calculate emission rates to comply with the proposed rules. If a governmental entity chooses to utilize an efficiency option to comply with the proposed rules, it may have to alter its general operating practices to favor more efficient units during applicable operating conditions. Costs to alter operating procedures for this option are not anticipated to be significant because they may be offset by savings generated by greater efficiencies, but any costs or savings would depend on the conditions found at each facility and cannot be quantified by staff. Therefore, this part of the proposed rules is not anticipated to have significant fiscal implications for governmental entities.

SUBCHAPTER D, DIVISION 2: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MINOR SOURCES

Current rules do not require owner/operators of minor sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area to control emissions. The proposed rules would require installation of control technology or combustion modifications on these minor sources. In effect, the proposed rules require that minor sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area comply with the same requirements as minor sources of NO_x in the Houston-Galveston-Brazoria ozone non attainment area. Affected owner/operators would also be required to comply with monitoring, recordkeeping, and reporting requirements. There may be as many as 1,057 boilers and 207 stationary internal combustion engines in the Dallas-Fort Worth eight-hour ozone nonattainment area that may be required to comply with the proposed rules by March 1, 2009. Owner/operators of boilers may have to install low-NO_x burners, and owner/operators of stationary internal combustion engines would either have to install emission controls or modify combustion methods to satisfy the requirements of the proposed rules.

Approximately 147 boilers that belong to independent school districts would be required to install low-NO_x burners. This is estimated to cost approximately $2.6 million for the burners and $441,000 for testing. Approximately 200 minor source boilers are owned by other city, county, and state governmental entities, 43 of which may be required to install low-NO_x burners. Total capital cost for the burners is estimated to be $994,000, and testing costs are estimated to cost $129,000. The remaining 157 boilers owned by other governmental entities would be required to install fuel meters on low fuel usage boilers to demonstrate that they are exempt from the requirements of the proposed rules for minor NO_x sources. Costs for fuel meters on 157 boilers are estimated to be $392,500. Total costs for all governmental entities owning minor source boilers could be as much as $4.6 million for the first five years the proposed rules are in effect. Annual costs for low-NO_x burners are estimated to be $600 per year per MMBtu/hr. Cost-effectiveness for the proposed emission reduction from minor sources is approximately $5,050 per ton of NO_x reduced.

SUBCHAPTER E, DIVISION 2: CEMENT KILNS

The proposed rules would require owners/operators of cement kilns in the Dallas-Fort Worth ozone nonattainment area to reduce NO_x emissions. There are ten cement kilns that might be required to install SNCR systems to comply with the proposed emission limits. No fiscal implications are anticipated for governmental entities as a result of this requirement because none of these kilns are owned or operated by them.

SUBCHAPTER E, DIVISION 3: WATER HEATERS, SMALL BOILERS, AND PROCESS HEATERS

The proposed rule would repeal current rules that require water heaters, small boilers, and process heaters throughout the state to meet specific NO_x emission limits. These rules were part of a SIP implementation strategy for attainment of ozone NAAQS. However, HB 965, 79th Legislature, 2005, required the agency to study the economic feasibility of regulating residential water heaters. Based on the study and comments received, the commission is proposing to repeal the 10 ng/J NO_x emissions standard for Type 0 water heaters and retain the current 40 ng/J NO_x emission standard. No fiscal implications are anticipated for governmental entities because the compliance date for the current rule has not yet been reached.

SUBCHAPTER E, DIVISION 4: EAST TEXAS COMBUSTION

The proposed rules would require owners/operators in 39 northeast Texas counties to limit NO_x emissions from stationary, gas-fired reciprocating, internal combustion engines. Approximately 854 of the 985 engines impacted by the proposed rules would need to make engine modifications or install controls to limit NO_x emissions. No local governments were identified as owners/operators of the engines expected to be affected by the proposed rules. If governmental entities in this region do own/operate such engines, they would incur the same costs as those incurred by business entities.

PUBLIC BENEFITS AND COSTS

Ms. Chamness also determined that for each year of the first five years the proposed new rules are in effect, the public benefit anticipated from the changes seen in the proposed rules would be greater ease and efficiency in the application of agency rules and improved air quality and health in the Dallas-Fort Worth nine-county eight-hour ozone nonattainment area due to lower ozone levels. It is estimated that the proposed rules would reduce the amount of NO_x in the affected areas by 68 tons per day. Lowering the level of ozone would benefit the public by enhancing the protection of public health and the environment.

Cost estimates that follow for major and minor NO_x sources are the same as those used to analyze total control, CEMS, annual operating, fuel meter, and testing costs for government al entities. Total capital, testing, and fuel meter costs for complying with all sections of the proposed rules in all the affected areas of the state could range from $255 million to $350.6 million for the first five years the rules are in effect.

SUBCHAPTER B, DIVISION 4: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MAJOR SOURCES

The proposed rules would require industrial owners/operators of major sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area to control emissions. There would be fiscal implications for industrial entities required to install controls or modify operations. Fiscal implications could be significant depending on the type of emission source, the size of the source, and the type of emission control technology chosen by the affected business. Cost-effectiveness for the proposed emission reduction is estimated to be between $3,800 and $5,700 per ton of NO_x reduced. Total capital, testing, and fuel meter costs to comply with this division of the proposed rules are estimated to range from $66 million to $82 million.

An estimated 50 out of 254 ICI boilers owned/operated by industry are anticipated to require installation of SCR. CEMS installation would also be required for 13 of the 50 heaters. The remaining 204 ICI boilers owned/operated by industry would require low-NO_x burners to meet emission specifications. Capital costs for SCR, capital costs for required CEMS, capital costs for low-NO_x burners, costs for fuel meters as needed, and costs for compliance testing could total as much as $29 million for all affected ICI boilers in the area for the first five years the rules are in effect. Estimates for annual costs for CEMS total $715,500. Annual costs for SCR and low-NO_x burners are estimated to be $4 million.

Approximately 55 process heaters; 116 natural gas heaters, dryers, and ovens; 22 brick and ceramic kilns; and four stationary gas turbines owned/operated by businesses are expected to install low-NO_x burners to comply with the proposed rules. The low-NO_x burners required for the 55 process heaters larger than 2 MMBtu/hr in the Dallas-Fort Worth eight-hour ozone nonattainment area are expected to cost $3,280 per MMBtu/hr for a total capital cost of $1.3 million, and associated annual costs are expected to be $219,000. Capital costs for low-NO_x burner installation for the 116 natural gas-fired heaters, dryers, and ovens are estimated to be $4.3 million. Annual costs are estimated at $739,000. It is expected that CEMS installation, costing $148,300 would be required at one of these units with annual costs estimated to be $48,000. For the 22 brick and ceramic kilns in the area, capital costs may be as much as $3.5 million, and annual costs may total $1.6 million. Capital costs to install low-NO_x burners for the four stationary gas turbines in the area are estimated to be $400,000 per unit, for an area-wide total of $1.6 million. Annual costs for low-NO_x burners installed at these turbines are estimated to total $210,000. Fuel metering costs for process heaters, natural gas heaters, dryers, and ovens, brick and ceramic kilns, and gas turbines are approximately $2,500 per meter for a combined total cost of $490,000 for all units. Initial compliance testing, estimated to cost $3,500 per control, for these units totals $609,000. All capital, monitoring, and testing costs for these units are estimated to total $11.9 million.

Oxy-fuel firing retrofits are expected to be needed at 11 glass and fiberglass melting furnaces in the area. In addition, there are 20 curing ovens for glass and fiberglass activities in the area. The retrofits for fiberglass producing furnaces may cost from $1.9 million to $5.07 million per plant and $9.8 million per plant for glass melting facilities. Total capital costs for all furnace retrofits are estimated to range from $13.7 million to $16.8 million. Annual costs associated with these retrofits are estimated to range from $706,000 to $4.1 million per plant. Installation of low-NO_x burners at the 20 curing ovens is estimated to cost $1.3 million. Annual costs for low-NO_x burners at the 20 curing ovens are estimated to be $220,000. Initial compliance testing for all 31 furnaces and ovens is estimated to cost $108,500, and total costs for required fuel meters are approximately $77,500. Total capital, testing, and fuel meter cost estimates for these units range from $15 million to $18 million.

The proposed rules would also require an estimated ten steel reheat/heat treat furnaces to install low-NO_x burners and two lead smelting furnaces to install low-NO_x burners and FGR to comply with emission specifications. Estimated capital costs for the steel reheat/heat treat furnaces are $1.5 million with annual costs of $287,000. Capital costs to install low-NO_x burners and FGR at the two lead smelting furnaces are estimated to range from $900 to $1,800 per ton of NO_x reduced. Total capital and annual costs for these furnaces cannot be accurately estimated because the control costs are based on EPA estimates for iron and copper smelting furnaces and actual reductions for this technology as applied to lead are unknown. Annual costs associated with control technologies are estimated to total $287,000. Installation of CEMS and associated CEMS annual costs are approximately $445,000 and $143,000, respectively. Required fuel meters are anticipated to cost $45,000 for all ten furnaces, and required initial compliance tests are projected to cost $52,500. Total capital, fuel meters, and testing are estimated at $2 million.

As many as 15 rich-burn and 32 lean-burn engines at major industrial NO_x sources in the Dallas-Fort Worth eight-hour ozone nonattainment area would require retrofit to comply with proposed emission standards. Based on the control costs discussed previously, capital costs associated with NSCR and secondary catalyst retrofits for 15 rich burn engines are estimated to be $635,439 with annual costs of $233,720. Capital costs associated with EGR with NSCR and secondary catalyst for all 32 lean-burn engines could total $2.1 million with associated annual costs projected to be $280,375. If SCR is installed for all 32 lean-burn engines, capital costs could be as high as $11.2 million for SCR plus $4.7 million in capital costs for any required CEMS controls. Annual costs for SCR and CEMS on 32 lean-burn engines are approximately $5.2 million and $1.5 million, respectively. Fuel meters, expected to be required for all engines that are not exempt, are estimated to total $125,000. All engines would be required to conduct initial and periodic compliance tests as well as quarterly tests. For all 47 engines, initial and periodic compliance tests are required along with three quarterly checks. These are estimated to cost $190,000 in the first year and every other year. Quarterly checks, required for years where periodic testing is not required, is estimated to cost $20,000 per year for all 47 engines. For the first five years the proposed rules are in effect, testing costs for these engines could total $570,000 in years one, three, and five and $40,000 for years two and four. Total testing costs for the first five years the rules are in effect are estimated to be $610,000. All capital, fuel meter, and testing costs for five years for these engine types could range from $3.4 million to $17 million depending on the control used for lean-burn engines.

As many as three incinerators would probably require installation of SCR and fuel meters. The capital costs for these controls at the three units are estimated at $3.6 million for SCR and $7,500 for fuel meters. Annual costs associated with SCR controls may be as much as $816,000. One of the three incinerators may also require CEMS installation at an estimated cost of $148,300 and associated annual costs projected at $47,700. Costs for initial compliance testing for all three incinerators are estimated at $7,000. Total capital, fuel meter, and testing costs are estimated to be $3.89 million.

Four lime kilns would require installation of CEMS for monitoring, if the kilns are not already equipped with CEMS. Capital costs for CEMS at the four kilns are estimated to be $593,200. Associated annual costs for CEMS at the four kilns are projected at $190,800. Fuel meters are expected to be required at the four kilns and are estimated to cost $10,000. All capital, CEMS, and fuel meter costs for these kilns are estimated to total $603,200.

The stationary diesel engines at major sources in the Dallas-Fort Worth eight-hour ozone nonattainment area are anticipated to be exempt from retrofit under the proposed rules because these engines are expected to be emergency back-up generators. If these engines become subject to the proposed rules, it would probably be more expensive to retrofit them with controls than to buy a new engine, which must meet EPA tier standards. If required to purchase a new engine, owners/operators could pay as much as $2,000 to $10,000 more than they would pay for an older diesel engine. Because it is not known how many of these engines could lose exemption under the proposed rules, staff cannot estimate area-wide costs of engine replacement.

SUBCHAPTER C, DIVISION 4: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

Businesses that own or operate utility boilers, auxiliary steam boilers, and stationary gas turbines at EGFs would be required to limit NO_x emissions to the appropriate emission specifications for each unit type under the proposed rules.

As many as four EGFs in the Dallas-Fort Worth nonattainment area are anticipated to be required to install SCR to meet proposed emission specifications. The installation of an SCR is estimated to cost of $125,000 per MW capacity. The total cost of installing an SCR would depend on the capacity of each of the four EGFs anticipated to need an SCR control, but estimates for area-wide capital costs could be as much as $87.5 million. In addition to capital costs, an EGF would also incur annual costs. The amount of these annual costs would depend on a number of factors including the capacity of the EGF and the ability to use available efficiency options to manage daily operations. Based on a concept of annual costs utilized by EPA, staff has estimated that these costs, area wide, could be as much as $5.45 million per year.

SUBCHAPTER D, DIVISION 2: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MINOR SOURCES

The proposed rules regarding minor NO_x emission sources in the Dallas-Fort Worth eight-hour ozone nonattainment area may require owners/operators of certain boilers, stationary internal combustion engines, gas turbines, and process heaters to limit emissions. If required to control emissions, owners/operators would incur control implementation costs as well as testing costs. Minor source boilers and internal combustion engines would be most affected by the proposed rules. The following cost detail is based on the same costs used in the cost analysis for major NO_x sources.

An estimated 867 boilers and 207 stationary internal combustion engines owned by businesses in the affected area would be subject to testing requirements. Total one-time initial testing costs for all 867 boilers is estimated to be $2.6 million. The estimated 207 engines would also be required to perform initial and periodic compliance tests as well as quarterly checks. For the first year and every other year, testing costs for all 207 engines could be as much as $683,100. For the second and fourth years, quarterly tests are estimated to be $82,800. For the first five years the rule is in effect, testing costs for engines are estimated to be $2.2 million. Combined area-wide testing costs for minor sources of NO_x is estimated to be $4.8 million for the first five years the proposed rules are in effect.

Owners or operators of process heaters and stationary diesel engines qualifying as minor sources are not expected to experience any fiscal implications for emission controls. Either their low emission levels or their use as emergency back-up generators are expected to comply with the proposed rules exemption definitions. If these heaters and engines fail to comply with the exemption specifications, owners/operators could incur costs to retrofit or buy new equipment.

Owners or operators of boilers and stationary gas-fired (rich-burn and lean-burn) engines that are classified as minor sources of NO_x may experience significant fiscal implications under the proposed rules if they are required to retrofit equipment, make combustion modifications, or install totalizing fuel flow meters.

There may be as many as 923 boilers owned by industry that would be exempt from the proposed rule due to low fuel usage. These boilers would be required to install fuel meters to demonstrate that they qualify for exemption from the proposed rules. Using a cost per fuel meter of $2,500, total fuel meter costs for these exempt boilers would total $2.3 million.

As many as 867 boilers in the Dallas-Fort Worth area may have to be retrofitted with low-NO_x burners. For all 867 boilers requiring retrofit, low-NO_x burner costs could be as much as $26 million, and associated annual costs could be as much as $600 per MMBtu/hr. Over the first five years the rules are in effect, total capital, testing, and fuel meter costs to retrofit minor source burners are estimated to be $33 million.

Under the proposed rules, approximately 207 stationary gas fired engines, of which 146 are rich-burn and 61 are lean-burn, would be required to install emission controls or make combustion modifications to comply with emission specifications. Required emission controls are likely to be NSCR with a secondary catalyst, a SCR, or an EGR kit.

Rich-burn engines would likely require installation of NSCR and secondary catalyst to meet the 0.50 g/hp-hr standard. An estimated 90 of the 146 rich-burn engines are expected to already have primary catalyst modules installed and would only need a secondary catalyst to complete the needed retrofit. For all 90 engines, secondary catalyst costs are estimated to total $202,500. Approximately 56 of the 146 rich-burn engines would need to install NSCR and a secondary catalyst. Installation of NSCR and a secondary catalyst for all 56 rich-burn engines totals approximately $1.26 million. In addition to NSCR and catalyst costs, owners or operators of these 146 rich-burn engines would incur annual operating costs estimated to total $377,000.

Installation of an EGR kit combined with NSCR or installation of SCR is expected to be required for 61 lean-burn engines to meet the 0.50 g/hp-hr standard of the proposed rules. Total capital costs for all 61 lean-burn engines, if installation of EGR and NSCR is chosen, are estimated to be $3.9 million with annual costs totaling $595,000 per year. Total capital costs for all 61 lean-burn engines, if SCR controls are used, could be as much as $20.9 million with annual costs of $9.6 million.

For the first five years the proposed rules are in effect, capital, monitoring, and testing costs for all affected boilers and engines at minor sources of NO_x emissions in the Dallas-Fort Worth eight-hour ozone nonattainment area could range from $38 million to $55 million depending on the control technology selected for lean-burn engines. Overall cost-effectiveness for controls on minor sources is estimated to range from $5,050 to $10,500 per ton of NO_x removed.

SUBCHAPTER E, DIVISION 2: CEMENT KILNS

The proposed rules would require owners or operators of cement kilns in the Dallas-Fort Worth ozone nonattainment area to reduce NO_x emissions. There are ten cement kilns, seven wet and three dry, that may be required to install SNCR systems to comply with the proposed emission limits. For wet kilns, capital costs are estimated to range from $1.2 million to $1.4 million for the installation of one SNCR system. Annual costs per system, which include costs for operation and maintenance, electricity, ammonia and/or urea, steam, overhead, taxes, insurance, administration, and capital recovery, could be as much as $300,000 to $500,000. Area-wide capital costs for all wet kilns may be as much as $8.4 million to $9.8 million. For dry kilns, capital costs for one SCR installation are estimated to be $2.3 million with annual costs of approximately $1 million. For all dry kilns, area-wide costs are estimated to be $6.9 million. The proposed rules would also require kiln owners or operators to incur additional monitoring costs upon the installation of SCR controls. Monitoring equipment is anticipated to cost $83,800 per unit, and annual costs per monitoring unit are estimated to be $19,000. Area-wide monitoring costs would total $838,000 for the ten kilns. Total capital costs for controls and monitoring equipment for all kilns are estimated to range from $16 million to $17.5 million. Overall cost-effectiveness is estimated to be $2,196 per ton of NO_x removed.

SUBCHAPTER E, DIVISION 3: WATER HEATERS, SMALL BOILERS, AND PROCESS HEATERS

Under current rules affecting water heaters, small boilers, and process heaters, those subject to the rules have not yet reached the deadline associated with meeting the 10 ng/J emission standard. Because of the repeal of this emissions limit under these proposed rules, persons subject to the rules would be able to continue manufacturing and selling water heaters that meet the 40 ng/J standard. Therefore, this part of the proposed rules would have no fiscal implication for the residential water heater industry.

SUBCHAPTER E, DIVISION 4: EAST TEXAS COMBUSTION

Owners or operators of stationary, gas-fired reciprocating, internal combustion engines equal to or greater than 50 hp in 39 northeast Texas counties would be required to limit NO_x emissions under the proposed rules. Approximately 854 of the estimated 985 engines in this area would need to make engine modifications or install controls to limit NO_x emissions.

All affected engines in the affected counties, whether they are required to limit emission controls or not, would be subject to testing requirements. Initial tests would cost approximately $3,000. Periodic tests, which must be performed every other year, are expected to cost the same. In addition, quarterly tests would be required to be conducted for three quarters in the first, third, and fifth years. Initial, periodic, and quarterly testing costs are estimated to be $3.25 million for the first, third, and fifth years. In the second and fourth years only, quarterly tests would be required. These quarterly tests are estimated to cost $100 each. Annual testing costs in the second and fourth years are estimated to be $394,000 per year. Total testing costs for the first five years the proposed rules are in affect are estimated to be $10.5 million.

Approximately 854 engines in northeast Texas would be required to install emission controls or make combustion modifications to meet the emission specifications of the proposed rules. Costs to install emission controls or make combustion modifications would vary depending on engine type (rich-burn or lean-burn) and size.

Approximately 557 rich-burn engines in northeast Texas would be required to install NSCR systems to meet the proposed 1.0 g/hp-hr standard for engines less than 500 hp or the 0.50 g/hp-hr standard for engines of 500 hp and greater. With the installation of NSCR, an additional catalyst module would also be required. The cost of an NSCR package is estimated to be $16,667 plus $16.67 per hp of the engine. A catalyst module required for NSCR installation, regardless of engine size, is estimated to cost $15 per hp. Total costs for NSCR installation plus additional catalyst for a 500 hp rich-burn engine could be as much as $33,000. For the 39-county region, total first-year capital costs for NSCR retrofits on rich-burn engines could total $16.8 million.

Approximately 297 lean-burn engines in northeast Texas would be required to retrofit those engines by installing an EGR kit combined with NSCR or by making LEC modifications. In general, costs for retrofitting engines using EGR combined with NSCR are lower than costs for LEC, but some engines might not be able to use an EGR kit and thus choose LEC. In some cases LEC may equal or exceed the cost of buying a new engine. There would also be annual recurring costs for both options. The capital cost of an EGR kit combined with NSCR is estimated to be $39,167 plus $41.67 per hp of the engine. LEC costs are estimated to be $226,000 plus $66.80 per hp. Annual recurring costs for EGR with NSCR are estimated to range from $23,000 to $56,000. For LEC, annual costs are estimated to be $57,800 plus $14.60 per hp. Total areas-wide costs are dependent on how many engines are retrofitted using the EGR/NSCR control approach and how many are controlled by LEC. If all lean-burn engines in the northeast Texas area utilize EGR/NSCR, capital costs alone could be as much as $20.5 million. If LEC is used area wide, total capital costs are estimated to be as much as $81.3 million.

Capital and testing costs for both rich-burn and lean-burn engines could range from $47.8 million to $108.6 million depending on the engine and the control technology chosen. Cost-effectiveness for the proposed emission reduction is approximately $1,980 per ton of NO_x reduced.

SMALL BUSINESS AND MICRO-BUSINESS ASSESSMENT

Adverse fiscal implications are anticipated for small or micro-businesses in the Dallas-Fort Worth eight-hour ozone nonattainment area and northeast Texas if they own sources of NO_x that would be regulated by the proposed rules. Staff is not able to determine the number of small or micro-businesses in the affected area, but dry cleaners or small hotels may be required to control emissions of small boilers by installing low-NO_x burners on a boiler averaging 5 MMBtu/hr. Costs to install low-NO_x burners on a boiler this size are estimated to be $15,500 with annual costs of $600 per MMBtu/hr. A small business is defined as having fewer than 100 employees and less than $1 million in annual gross receipts. A micro-business is defined as having no more than 20 employees. If a small or micro-business has a small boiler and installs a low-NO_x burner to meet the requirements of the proposed rules, the cost per employee for a small business is estimated to be $161 during the first year the proposed rules are implemented and $6.00 per employee in the second through fifth years. For a micro-business, the cost is estimated to be $805 per employee during the first year of implementation and $30 per employee in the second through fifth years.

LOCAL EMPLOYMENT IMPACT STATEMENT

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

DRAFT REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed the proposed rulemaking for a new Chapter 117 in 30 TAC in light of the regulatory impact analysis requirements of Texas Government Code, §2001.0225, and determined that, except for the proposed repeal and reformatting of Chapter 117 and as specifically discussed later regarding proposed rules in Subchapter E, Division 3, the proposed rulemaking meets the definition of a major environmental rule as defined in that statute. A major environmental rule means a rule, the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure, and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

The proposed repeal and reformatting of Chapter 117 is necessary to accommodate new proposed rules for the eight-hour ozone attainment demonstration and to provide for future potential rulemaking. The reformatting includes proposed minor technical changes and corrections to existing language for rule language associated with the one-hour ozone NAAQS. The repeal and reformatting of Chapter 117, if adopted, will not negatively impact the status of the state's attainment with the ozone NAAQS because all existing rules remain in effect until the effective date of the proposed reformatted chapter. All requirements in the existing rules for the one-hour ozone NAAQS, applicable to a particular region or area that the rules apply to, have been incorporated into the proposed new formatted rules. This is necessary so there will be no backsliding or temporary lapse in the enforcement or effectiveness of the current requirements in 30 TAC Chapter 117.

The proposed rulemaking does not, however, meet any of the four applicability criteria for requiring a regulatory impact analysis for a major environmental rule, which are listed in Texas Government Code, §2001.0225(a). Texas Government Code, §2001.0225, applies only to a major environmental rule, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

Specifically, the remainder of this rulemaking can be summarized as indicated in the following categories.

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

DIVISION 4: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MAJOR SOURCES

These rules propose new emission control requirements for major ICI sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area. These rules are a part of the area's attainment demonstration and the emission reductions associated with this rulemaking will help bring the area into compliance with the eight-hour ozone NAAQS.

Specifically, the proposed new Subchapter B, Division 4 would require owners or operators of major ICI sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area to reduce NO_x emissions from a wide variety of stationary sources. The proposed rules also include monitoring, testing, recordkeeping, reporting, and other requirements associated with the proposed emission specifications necessary to ensure compliance with the emission specifications and that the necessary NO_x emission reductions will be achieved.

Further, the emission specifications for attainment demonstration in proposed new §117.410 specify stricter emission limits for NO_x for all unit and industry types in the Dallas-Fort Worth eight-hour nonattainment area that are specified in the EPA's Alternative Controls Techniques (ACT). The FCAA RACT requirement would be fulfilled by the emission specifications for attainment demonstration proposed in §117.410 for the Dallas-Fort Worth eight-hour ozone nonattainment area.

If these rules are adopted, the emission reductions will result in reductions in ozone formation in the Dallas-Fort Worth eight-hour ozone nonattainment area, and help bring the area into compliance with the eight-hour ozone NAAQS. These emission reductions are one component of the Dallas-Fort Worth attainment demonstration SIP revision the state is required to submit to EPA to assure attainment and maintenance of the eight-hour ozone NAAQS, and the proposed new rules in Subchapter B, Division 4 are one step toward meeting the state's obligations under the FCAA.

SUBCHAPTER C: COMBUSTION CONTROL AT MAJOR UTILITY ELECTRIC GENERATION SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 4: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

These rules propose new requirements for utility electric generation sources in the Dallas-Fort Worth eight-hour ozone nonattainment area. These rules are a part of the area's attainment demonstration and the emission reductions associated with this rulemaking will help bring the area into compliance with the eight-hour ozone NAAQS.

Specifically, the proposed new Subchapter C, Division 4 would apply to utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in turbine exhaust ducts used in an electric power generating system owned or operated by a municipality or a PUC-regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC; or an electric cooperative, independent power producer, municipality, river authority, or public utility located within the Dallas-Fort Worth eight-hour ozone nonattainment area. The proposed rules establish a unit-by-unit, or command and control-based system for compliance with the existing emission specifications for units subject to the proposed rule. Further, as discussed elsewhere in this preamble, the rules satisfy RACT requirements for the five new counties in the nine-county Dallas-Fort Worth eight-hour ozone nonattainment area.

If these rules are adopted, the emission reductions will result in reductions in ozone formation in the Dallas-Fort Worth eight-hour ozone nonattainment area, and help bring the area into compliance with the eight-hour ozone NAAQS. These emission reductions are one component of the Dallas-Fort Worth attainment demonstration SIP revision the state is required to submit to EPA to assure attainment and maintenance of the eight-hour ozone NAAQS, and the proposed new rules in Subchapter C, Division 4 are one step toward meeting the state's obligations under the FCAA.

SUBCHAPTER D: COMBUSTION CONTROL AT MINOR SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 2: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MINOR SOURCES

These rules propose requirements for minor stationary sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area to meet new emission specifications and other reductions of NO_x emissions from affected boilers, process heaters, stationary internal combustion engines, and gas turbines (including duct burners). This proposed rulemaking would regulate units at sites including small businesses and industries, hospitals, hotels, public and private office and administrative buildings, and school districts that were previously unregulated.

If these rules are adopted, the emission reductions will result in reductions in ozone formation in the Dallas-Fort Worth eight-hour ozone nonattainment area, and help bring the area into compliance with the eight-hour ozone NAAQS. These emission reductions are one component of the Dallas-Fort Worth attainment demonstration SIP revision the state is required to submit to EPA to assure attainment and maintenance of the eight-hour ozone NAAQS, and the proposed new rules in Subchapter D, Division 2 are one step toward meeting the state's obligations under the FCAA.

SUBCHAPTER E: MULTI-REGION COMBUSTION CONTROL

DIVISION 2: CEMENT KILNS

These rules implement a proposed control strategy for cement kilns in the Dallas-Fort Worth eight-hour ozone nonattainment area. Specifically, the commission is proposing a source-cap approach to establish a maximum NO_x emission cap for each account. As discussed elsewhere in this preamble, these rules are based on the commission's evaluation of the "Assessment of NO_x Emissions Reduction Strategies for Cement Kilns--Ellis County: Final Report," together with modeling sensitivity studies, and all other available information. A source cap allows an owner or operator to choose the most applicable and cost-effective control technology available to a particular kiln while still achieving the overall reductions modeled for the Dallas-Fort Worth eight-hour attainment demonstration. Owners or operators may use any of the control technologies identified in the final report of the control technology study to achieve reductions for compliance with the source cap. Before an increase in NO_x emissions from a change in operation from one unit or the installation of a new kiln could occur, a corresponding and equivalent decrease in NO_x emission would be required from another existing unit.

If these rules are adopted, the emission reductions will result in reductions in ozone formation in the Dallas-Fort Worth eight-hour ozone nonattainment area, and help bring the area into compliance with the eight-hour ozone NAAQS. These emission reductions are one component of the Dallas-Fort Worth attainment demonstration SIP revision the state is required to submit to EPA to assure attainment and maintenance of the eight-hour ozone NAAQS, and the proposed new rules in Subchapter E, Division 2 are one step toward meeting the state's obligations under the FCAA.

DIVISION 4: EAST TEXAS COMBUSTION

The primary purpose of the proposed new rules is to require affected gas-fired stationary, reciprocating internal combustion engines in certain counties in the northeast Texas area to meet new NO_x emission specifications and other requirements in order to reduce NO_x emissions and ozone air pollution transport into the Dallas-Fort Worth eight-hour ozone nonattainment area. The specific counties included in the applicability for this proposed rulemaking include the following counties: Anderson, Bosque, Brazos, Burleson, Camp, Cass, Cherokee, Cooke, Franklin, Freestone, Grayson, Gregg, Grimes, Harrison, Henderson, Hill, Hood, Hopkins, Hunt, Lee, Leon, Limestone, Madison, Marion, Morris, Nacogdoches, Navarro, Panola, Rains, Robertson, Rusk, Shelby, Smith, Somervell, Titus, Upshur, Van Zandt, Wise, and Wood Counties.

If these rules are adopted, the emission reductions will result in reductions in ozone formation in the Dallas-Fort Worth eight-hour ozone nonattainment area, and help bring the area into compliance with the eight-hour ozone NAAQS. These emission reductions are one component of the Dallas-Fort Worth attainment demonstration SIP revision the state is required to submit to EPA to assure attainment and maintenance of the eight-hour ozone NAAQS, and the proposed new rules in Subchapter E, Division 4 are one step toward meeting the state's obligations under the FCAA.

ANALYSIS

The proposed new Chapter 117 rulemaking would implement requirements of the FCAA. Under 42 USC, §7410, each state is required to adopt and implement a state implementation plan containing adequate provisions to implement, attain, maintain, and enforce the NAAQS within the state. While 42 USC, §7410 generally does not require specific programs, methods, or reductions in order to meet the standard, state SIPs must include "enforceable emission limitations and other control measures, means or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance as may be necessary or appropriate to meet the applicable requirements of this chapter," (meaning Chapter 85, Air Pollution Prevention and Control, otherwise known as the Federal Clean Air Act). The provisions of the FCAA recognize that states are in the best position to determine what programs and controls are necessary or appropriate in order to meet the NAAQS. This flexibility allows states, affected industry, and the public, to collaborate on the best methods for attaining the NAAQS for the specific regions in the state. Even though the FCAA allows states to develop their own programs, this flexibility does not relieve a state from developing a program that meets the requirements of 42 USC, §7410. States are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that their state implementation plans provide for implementation, attainment, maintenance, and enforcement of the NAAQS within the state.

The requirement to provide a fiscal analysis of proposed regulations in the Texas Government Code was amended by Senate Bill (SB) 633 during the 75th legislative session. The intent of SB 633 was to require agencies to conduct a regulatory impact analysis of extraordinary rules. These are identified in the statutory language as major environmental rules that will have a material adverse impact and will exceed a requirement of state law, federal law, or a delegated federal program, or are adopted solely under the general powers of the agency. With the understanding that this requirement would seldom apply, the commission provided a cost estimate for SB 633 that concluded "based on an assessment of rules adopted by the agency in the past, it is not anticipated that the bill will have significant fiscal implications for the agency due to its limited application." The commission also noted that the number of rules that would require assessment under the provisions of the bill was not large. This conclusion was based, in part, on the criteria set forth in the bill that exempted proposed rules from the full analysis unless the rule was a major environmental rule that exceeds a federal law.

As discussed earlier in this preamble, the FCAA does not always require specific programs, methods, or reductions in order to meet the NAAQS; thus, states must develop programs for each nonattainment area to help ensure that those areas will meet the attainment deadlines. Because of the ongoing need to address nonattainment issues, and to meet the requirements of 42 USC, §7410, the commission routinely proposes and adopts SIP rules. The legislature is presumed to understand this federal scheme. If each rule proposed for inclusion in the SIP was considered to be a major environmental rule that exceeds federal law, then every SIP rule would require the full RIA contemplated by SB 633. This conclusion is inconsistent with the conclusions reached by the commission in its cost estimate and by the Legislative Budget Board (LBB) in its fiscal notes. Since the legislature is presumed to understand the fiscal impacts of the bills it passes, and that presumption is based on information provided by state agencies and the LBB, the commission believes that the intent of SB 633 was only to require the full RIA for rules that are extraordinary in nature. While the SIP rules will have a broad impact, that impact is no greater than is necessary or appropriate to meet the requirements of the FCAA. For these reasons, rules adopted for inclusion in the SIP fall under the exception in Texas Government Code, §2001.0225(a), because they are required by federal law.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code, but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." (*Central Power & Light Co. v. Sharp,* 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue,* 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.,* 798 S.W.2d 353, 357 (Tex. App. Austin 1990, *no writ). Cf. Humble Oil & Refining Co. v. Calvert,* 414 S.W.2d 172 (Tex. 1967); *Dudney v. State Farm Mut. Auto Ins. Co.,* 9 S.W.3d 884, 893 (Tex. App. Austin 2000); *Southwestern Life Ins. Co. v. Montemayor,* 24 S.W.3d 581 (Tex. App. Austin 2000, *pet. denied);* and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.,* 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." (Texas Government Code, §2001.035.) The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

The specific intent of the proposed rules is to protect the environment and to reduce risks to human health, particularly in the state's ozone nonattainment areas, by adoption of the proposed new rules in Chapter 117. The proposed rules do not exceed a standard set by federal law or exceed an express requirement of state law. No contract or delegation agreement covers the topic that is the subject of this rulemaking. Finally, this rulemaking was not developed solely under the general powers of the agency, but is required by the Texas Clean Air Act, as codified in Texas Health and Safety Code (THSC), §382.0173. Therefore, this rulemaking is not subject to the regulatory analysis provisions of Texas Government Code, §2001.0225(b), because, although the proposed rule meets the definition of a major environmental rule, it does not meet any of the four applicability criteria for a major environmental rule.

The commission invites public comment regarding the draft regulatory impact analysis determination during the public comment period.

DRAFT REGULATORY IMPACT ANALYSIS DETERMINATION

SUBCHAPTER E: MULTI-REGION COMBUSTION CONTROL

DIVISION 3, WATER HEATERS, SMALL BOILERS, AND PROCESS HEATERS

The commission reviewed the proposed rulemaking action in Subchapter E, Division 3 of Chapter 117 in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and determined that the rulemaking action does not meet the definition of a major environmental rule as defined in that statute. A major environmental rule is a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure and that may adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

The primary purpose of this proposed rulemaking action in this division is to repeal the current 10 ng/J NO_x emission standard for certain gas-fired residential water heaters, as set forth in §117.465(b)(2). This emission standard has never become effective. The effective date has been extended through a prior adopted rulemaking, and it has subsequently been determined that compliance with the 10 ng/J standard for Type 0 units is not currently achievable. The basis for this determination is discussed earlier in this preamble in greater detail. All water heaters must still meet the 40 ng/J emission standard in the existing rules. The original rules, adopted on April 19, 2000, did not constitute a major environmental rulemaking action, and the proposed amendments to the existing rules are minor in nature. Therefore, the proposed rulemaking does not constitute a major environmental rule, and thus not subject to a formal regulatory analysis.

If these rules are adopted, emission reductions from the remaining emission standards in the rules will result in reductions in ozone formation in the Dallas-Fort Worth eight-hour ozone nonattainment area, and help bring the area into compliance with the eight-hour ozone NAAQS. These emission reductions are one component of the Dallas-Fort Worth attainment demonstration SIP revision the state is required to submit to EPA to assure attainment and maintenance of the eight-hour ozone NAAQS, and the proposed new rules in Subchapter E, Division 3 are one step toward meeting the state's obligations under the FCAA.

In addition, this proposed rulemaking does not meet any of the four applicability criteria of a major environmental rule as defined in the Texas Government Code. Texas Government Code, §2001.0225 applies only to a major environmental rule the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

The rulemaking action, which repeals the current 10 ng/J NO_x emission standard for certain gas-fired residential water heaters does not exceed a federal requirement, and is required under recently passed state legislation. Furthermore, there is no contract or delegation agreement that covers the topic that is the subject of this action. Finally, this rulemaking action was not developed solely under the general powers of the agency, but is authorized by specific sections of Texas Health and Safety Code, Chapter 382 (also known as the Texas Clean Air Act), and the Texas Water Code, which are cited in the STATUTORY AUTHORITY section of this preamble, including Texas Health and Safety Code, §§382.011, 382.012, and 382.017. Therefore, the proposed rulemaking does not exceed a standard set by federal law, exceed an express requirement of state law, exceed a requirement of a delegation agreement, nor is adopted solely under the general powers of the agency.

Based upon the foregoing, this rulemaking action is not subject to the regulatory analysis provisions of Texas Government Code, §2001.0225.

The commission invites public comment regarding the draft regulatory impact analysis determination during the public comment period.

TAKINGS IMPACT ASSESSMENT

Under Texas Government Code, §2007.002(5), taking means a governmental action that affects private real property, in whole or in part or temporarily or permanently, in a manner that requires the governmental entity to compensate the private real property owner as provided by the Fifth and Fourteenth Amendments to the United States Constitution or §17 or §19, Article I, Texas Constitution; or a governmental action that affects an owner's private real property that is the subject of the governmental action, in whole or in part or temporarily or permanently, in a manner that restricts or limits the owner's right to the property that would otherwise exist in the absence of the governmental action; and is the producing cause of a reduction of at least 25% in the market value of the affected private real property, determined by comparing the market value of the property as if the governmental action is not in effect and the market value of the property determined as if the governmental action is in effect.

The commission completed a takings impact analysis for the proposed rulemaking action under Texas Government Code, §2007.043. The primary purpose of this proposed rulemaking action is summarized in the following paragraphs.

CHAPTER 117 REFORMAT

The proposed repeal and reformatting of Chapter 117 is necessary to accommodate new proposed rules for the eight-hour ozone attainment demonstration and to provide for future potential rulemaking. The proposed reformatted Chapter 117 would also provide for easier understanding of what rules are applicable in different geographical areas of the state. The reformatting includes proposed minor technical changes and corrections to existing language for rule language associated with the one-hour ozone NAAQS. The repeal and reformatting of Chapter 117 will not negatively impact the status of the state's attainment with the ozone NAAQS because all existing rules remain in effect until the effective date of the proposed reformatted chapter, if adopted. All requirements in the existing rules for the one-hour ozone NAAQS, applicable to a particular region or area that the rule applies to, have been incorporated into the proposed new formatted rules. This is necessary so there will be no backsliding or temporary lapse in the enforcement or effectiveness of the current requirements in 30 TAC Chapter 117.

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

DIVISION 4: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MAJOR SOURCES

These rules propose new emission control requirements for major industrial, commercial, or institutional (ICI) sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area. These rules are a part of the area's attainment demonstration and the emission reductions associated with this rulemaking will help bring the area into compliance with the eight-hour ozone NAAQS.

Specifically, the proposed new sections of Subchapter B, Division 4 would require owners or operators of major ICI sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area to reduce NO_x emissions from a wide variety of stationary sources. The proposed rules also include monitoring, testing, recordkeeping, reporting, and other requirements associated with the proposed emission specifications necessary to ensure compliance with the emission specifications and that the necessary NO_x emission reductions will be achieved.

Further, the emission specifications for attainment demonstration in proposed new §117.410 specify stricter emission limits for NO_x for all unit and industry types in the Dallas-Fort Worth eight-hour nonattainment area specified in the EPA's Alternative Controls Techniques (ACT). The FCAA RACT requirement would be fulfilled by the emission specifications for attainment demonstration proposed in §117.410 for the Dallas-Fort Worth eight-hour ozone nonattainment area.

SUBCHAPTER C: COMBUSTION CONTROL AT MAJOR UTILITY ELECTRIC GENERATION SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 4: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

These rules propose new requirements for utility electric generation sources in the Dallas-Fort Worth eight-hour ozone nonattainment area. These rules are a part of the area's attainment demonstration and the emission reductions associated with this rulemaking will help bring the area into compliance with the eight-hour ozone NAAQS.

Specifically, the proposed new Subchapter C, Division 4 would apply to utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in turbine exhaust ducts used in an electric power generating system owned or operated by a municipality or a PUC-regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC; or an electric cooperative, independent power producer, municipality, river authority, or public utility located within the Dallas-Fort Worth eight-hour ozone nonattainment area. The proposed rules establish a unit-by-unit, or command and control based system for compliance with the existing emission specifications for units subject to the proposed rule. Further, as discussed elsewhere in this preamble, the rules satisfy RACT requirements for the five new counties in the nine-county Dallas-Fort Worth eight-hour ozone nonattainment area.

SUBCHAPTER D: COMBUSTION CONTROL AT MINOR SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 2: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MINOR SOURCES

These rules propose requirements for minor stationary sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area to meet new emission specifications and other reductions of NO_x emissions from affected boilers, process heaters, stationary internal combustion engines, and gas turbines (including duct burners). This proposed rulemaking would regulate units at sites including small businesses and industries, hospitals, hotels, public and private office and administrative buildings, and school districts that were previously unregulated.

SUBCHAPTER E: MULTI-REGION COMBUSTION CONTROL

DIVISION 2: CEMENT KILNS

These rules implement a proposed control strategy for cement kilns in the Dallas-Fort Worth eight-hour ozone nonattainment area. Specifically, the commission is proposing a source-cap approach to establish a maximum NO_x emission cap for each account. As discussed elsewhere in this preamble, these rules are based on the commission's evaluation of the "Assessment of NO_x Emissions Reduction Strategies for Cement Kilns--Ellis County: Final Report," together with modeling sensitivity studies, and all other available information. A source cap allows an owner or operator to choose the most applicable and cost-effective control technology available to a particular kiln while still achieving the overall reductions modeled for the Dallas-Fort Worth eight-hour attainment demonstration. Owners or operators may use any of the control technologies identified in the final report of the control technology study to achieve reductions for compliance with the source cap. Before an increase in NO_x emissions from a change in operation from one unit or the installation of a new kiln could occur, a corresponding and equivalent decrease in NO_x emission would be required from another existing unit.

DIVISION 3, WATER HEATERS, SMALL BOILERS, AND PROCESS HEATERS

The primary purpose of this division is to repeal the current 10 ng/J NO_x emission standard for certain gas-fired residential water heaters, as set forth in §117.465(b)(2). This emission standard has never become effective. The effective date has been extended through prior rulemaking, and it has subsequently been determined that compliance with the 10 ng/J standard for Type 0 units is not currently achievable. The basis for this determination is discussed earlier in this preamble in greater detail. All water heaters must still meet the 40 ng/J emission standard in the existing rules.

DIVISION 4: EAST TEXAS COMBUSTION

The primary purpose of the proposed new rules is to require affected gas-fired stationary, reciprocating internal combustion engines in certain counties in the northeast Texas area to meet new NO_x emission specifications and other requirements in order to reduce NO_x emissions and ozone air pollution transport into the Dallas-Fort Worth eight-hour ozone nonattainment area. The specific counties included in the applicability for this proposed rulemaking include the following counties: Anderson, Bosque, Brazos, Burleson, Camp, Cass, Cherokee, Cooke, Franklin, Freestone, Grayson, Gregg, Grimes, Harrison, Henderson, Hill, Hood, Hopkins, Hunt, Lee, Leon, Limestone, Madison, Marion, Morris, Nacogdoches, Navarro, Panola, Rains, Robertson, Rusk, Shelby, Smith, Somervell, Titus, Upshur, Van Zandt, Wise, and Wood Counties.

The proposed new Chapter 117 will not affect private real property in a manner that would require compensation to private real property owners under the United States Constitution or the Texas Constitution. The proposal also will not affect private real property in a manner that restricts or limits an owner's right to the property that would otherwise exist in the absence of the governmental action. Therefore, the proposed rulemaking will not cause a taking under Texas Government Code, Chapter 2007.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission determined the proposed rulemaking relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 *et seq).,* and the commission rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with the Texas Coastal Management Program. As required by 30 TAC §281.45(a)(3) and 31 TAC §505.11(b)(2), relating to actions and rules subject to the

CMP, commission rules governing air pollutant emissions must be consistent with the applicable goals and policies of the CMP. The commission reviewed this action for consistency with the CMP goals and policies in accordance with the regulations of the Coastal Coordination Council and determined that the proposed amendments are consistent with the applicable CMP goal expressed in 31 TAC §501.12(1) of protecting and preserving the quality and values of coastal natural resource areas, and the policy in 31 TAC §501.14(q), which requires that the commission protect air quality in coastal areas. The proposed rulemaking and SIP revision would ensure that the amendments comply with 40 CFR Part 50, National Primary and Secondary Air Quality Standards, and 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans. This rulemaking action is consistent with CMP goals and policies, in compliance with 31 TAC §505.22(e).

The commission solicits comments on the consistency of the proposed rulemaking with the CMP during the public comment period.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMITS PROGRAM

Chapter 117 is an applicable requirement under 30 TAC Chapter 122, Federal Operating Permits Program. If the proposed new Chapter 117 is adopted, owners or operators subject to the federal operating permit program must, consistent with the revision process in Chapter 122, upon the effective date of the rulemaking, revise their operating permit to include the new Chapter 117 requirements.

ANNOUNCEMENT OF PUBLIC HEARINGS

Public hearings on this proposal will held on January 29, 2007, at 2:00 p.m. and 6:00 p.m. at the Houston-Galveston Area Council, Conference Room A, Suite 120, 3555 Timmons Lane, Houston; January 31, 2007, 7:00 p.m., J. Erik Jonsson Central Library Auditorium, 1515 Young Street, Dallas; February 1, 2007, at 2:00 p.m., Arlington City Hall Council Chambers, 101 W. Abrams Street, Arlington; February 1, 2007, at 6:00 p.m., Midlothian Conference Center, 1 Community Circle, Midlothian; February 6, 2007, at 2:00 p.m., Longview Public Library, 222 W. Cotton Street, Longview; and February 8, 2007, at 2:00 p.m., Texas Commission on Environmental Quality, 12100 Park 35 Circle, Building E, Room 201S, Austin. Individuals may present oral statements when called upon in order of registration. A time limit may be established at each hearing to assure that enough time is allowed for every interested person to speak. Open discussion will not occur during the hearings; however, a staff member will be available to discuss the proposal 30 minutes before the hearings.

Persons who have special communication or other accommodation needs, who are planning to attend the hearings, should contact Jennifer Stifflemire, Air Quality Division, at (512) 239-0573. Requests should be made as far in advance as possible.

SUBMITTAL OF COMMENTS

Comments may be submitted to Joyce Spencer, MC 205, Texas Commission on Environmental Quality, P.O. Box 13087, Austin, Texas 78711-3087; or faxed to (512) 239-4808. Electronic comments may be submitted at *http://www5.tceq.state.tx.us/rules/ecomments/.* All comments should reference Rule Project Number 2006-034-117-EN. The comment period closes February 12, 2007. For further information, please contact Vincent Meiller of the Air Quality Division at (512) 239-6041.

SUBCHAPTER A. DEFINITIONS

30 TAC §117.10

(Editor's note: The text of the following section proposed for repeal will not be published. The section may be examined in the offices of the Texas Commission on Environmental Quality or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

STATUTORY AUTHORITY

The repeal is proposed 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 repeal is proposed 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 repeal is proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed repeal implements Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.10. Definitions.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 15, 2006.

TRD-200606703

Robert Martinez

Director, Environmental Law Division

Texas Commission on Environmental Quality

Earliest possible date of adoption: January 28, 2007

For further information, please call: (512) 239-5017

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SUBCHAPTER B. COMBUSTION AT MAJOR SOURCES

DIVISION 1. UTILITY ELECTRIC GENERATION IN OZONE NONATTAINMENT AREAS

30 TAC §§117.101, 117.103, 117.105 - 117.111, 117.113 - 117.117, 117.119, 117.121

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Commission on Environmental Quality or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

STATUTORY AUTHORITY

The repeals are proposed 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 repeals are proposed 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 repeals are proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed repeals implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.101. Applicability.

§117.103. Exemptions.

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

§117.106. Emission Specifications for Attainment Demonstrations.

§117.107. Alternative System-wide Emission Specifications.

§117.108. System Cap.

§117.109. System Cap Flexibility.

§117.110. Change of Ownership - System Cap.

§117.111. Initial Demonstration of Compliance.

§117.113. Continuous Demonstration of Compliance.

§117.114. Emission Testing and Monitoring for the Houston-Galveston Attainment Demonstration.

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

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

§117.117. Revision of Final Control Plan.

§117.119. Notification, Recordkeeping, and Reporting Requirements.

§117.121. Alternative Case Specific Specifications.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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DIVISION 2. UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS

30 TAC §§117.131, 117.133 - 117.135, 117.138, 117.139, 117.141, 117.143, 117.145, 117.147, 117.149, 117.151

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Commission on Environmental Quality or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

STATUTORY AUTHORITY

The repeals are proposed 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 repeals are proposed 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 repeals are proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed repeals implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.131. Applicability.

§117.133. Exemptions.

§117.134. Gas-Fired Steam Generation.

§117.135. Emission Specifications.

§117.138. System Cap.

§117.139. System Cap Flexibility.

§117.141. Initial Demonstration of Compliance.

§117.143. Continuous Demonstration of Compliance.

§117.145. Final Control Plan Procedures.

§117.147. Revision of Final Control Plan.

§117.149. Notification, Recordkeeping, and Reporting Requirements.

§117.151. Alternative Case Specific Specifications.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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DIVISION 3. INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL COMBUSTION SOURCES IN OZONE NONATTAINMENT AREAS

30 TAC §§117.201, 117.203, 117.205 - 117.211, 117.213 - 117.217, 117.219, 117.221, 117.223

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Commission on Environmental Quality or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

STATUTORY AUTHORITY

The repeals are proposed 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 repeals are proposed 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 repeals are proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed repeals implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.201. Applicability.

§117.203. Exemptions.

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

§117.206. Emission Specifications for Attainment Demonstrations.

§117.207. Alternative Plant-wide Emission Specifications.

§117.208. Operating Requirements.

§117.209. Initial Control Plan Procedures.

§117.210. System Cap.

§117.211. Initial Demonstration of Compliance.

§117.213. Continuous Demonstration of Compliance.

§117.214. Emission Testing and Monitoring for the Houston-Galveston Attainment Demonstration.

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

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

§117.217. Revision of Final Control Plan.

§117.219. Notification, Recordkeeping, and Reporting Requirements.

§117.221. Alternative Case Specific Specifications.

§117.223. Source Cap.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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DIVISION 4. CEMENT KILNS

30 TAC §§117.260, 117.261, 117.265, 117.273, 117.279, 117.283

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Commission on Environmental Quality or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

STATUTORY AUTHORITY

The repeals are proposed 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 repeals are proposed 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 repeals are proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed repeals implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.260. Cement Kiln Definitions.

§117.261. Applicability.

§117.265. Emission Specifications.

§117.273. Continuous Demonstration of Compliance.

§117.279. Notification, Recordkeeping, and Reporting Requirements.

§117.283. Source Cap.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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SUBCHAPTER C. ACID MANUFACTURING

DIVISION 1. ADIPIC ACID MANUFACTURING

30 TAC §§117.301, 117.305, 117.309, 117.311, 117.313, 117.319, 117.321

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Commission on Environmental Quality or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

STATUTORY AUTHORITY

The repeals are proposed 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 repeals are proposed 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 repeals are proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed repeals implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.301. Applicability.

§117.305. Emission Specifications.

§117.309. Control Plan Procedures.

§117.311. Initial Demonstration of Compliance.

§117.313. Continuous Demonstration of Compliance.

§117.319. Notification, Recordkeeping, and Reporting Requirements.

§117.321. Alternative Case Specific Specifications.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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DIVISION 2. NITRIC ACID MANUFACTURING--OZONE NONATTAINMENT AREAS

30 TAC §§117.401, 117.405, 117.409, 117.411, 117.413, 117.419, 117.421

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Commission on Environmental Quality or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

STATUTORY AUTHORITY

The repeals are proposed 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 repeals are proposed 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 repeals are proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed repeals implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.401. Applicability.

§117.405. Emission Specifications.

§117.409. Control Plan Procedures.

§117.411. Initial Demonstration of Compliance.

§117.413. Continuous Demonstration of Compliance.

§117.419. Notification, Recordkeeping, and Reporting Requirements.

§117.421. Alternative Case Specific Specifications.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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DIVISION 3. NITRIC ACID MANUFACTURING--GENERAL

30 TAC §§117.451, 117.455, 117.458

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Commission on Environmental Quality or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

STATUTORY AUTHORITY

The repeals are proposed 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 repeals are proposed 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 repeals are proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed repeals implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.451. Applicability.
§117.455. Emission Specifications.
§117.458. Applicability of Federal New Source Performance Standards.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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SUBCHAPTER D. SMALL COMBUSTION SOURCES
DIVISION 1. WATER HEATERS, SMALL BOILERS, AND PROCESS HEATERS

30 TAC §§117.460, 117.461, 117.463, 117.465, 117.467, 117.469

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Commission on Environmental Quality or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

STATUTORY AUTHORITY

The repeals are proposed under Texas Water Code, §5.102, concerning General Powers, §5.103, concerning Rules, and §5.105, concerning General Policy, that authorize the commission to adopt rules necessary to carry out its powers and duties under the Texas Water Code. In addition, the repeals are proposed 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. The repeals are proposed under federal mandates contained in 42 United States Code, §§7410 *et. seq.,* that require states to adopt pollution control measures in order to reach specific air quality standards in particular areas of the state. In addition, the repeals are proposed to implement the legislative mandate under House Bill (HB) 965, 79th Legislature, 2005, which adds Texas Health and Safety Code, §382.0275, concerning Commission Action Relating to Residential Water Heaters, which requires certain actions of the commission regarding residential water heaters.

The proposed repeals implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, and 382.0275.

§117.460. Definitions.
§117.461. Applicability.
§117.463. Exemptions.
§117.465. Emission Specifications.
§117.467. Certification Requirements.
§117.469. Notification and Labeling Requirements.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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DIVISION 2. BOILERS, PROCESS HEATERS, AND STATIONARY ENGINES AND GAS TURBINES AT MINOR SOURCES

30 TAC §§117.471, 117.473, 117.475, 117.478, 117.479, 117.481

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Commission on Environmental Quality or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

STATUTORY AUTHORITY

The repeals are proposed 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 repeals are proposed 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 repeals are proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed repeals implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.471. Applicability.

§117.473. Exemptions.

§117.475. Emission Specifications.

§117.478. Operating Requirements.

§117.479. Monitoring, Recordkeeping, and Reporting Requirements.

§117.481. Alternative Case Specific Specifications.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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SUBCHAPTER E. ADMINISTRATIVE PROVISIONS

30 TAC §§117.510, 117.512, 117.520, 117.524, 117.530, 117.534, 117.570, 117.571

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Commission on Environmental Quality or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

STATUTORY AUTHORITY

The repeals are proposed 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 repeals are proposed 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 repeals are proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed repeals implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.510. Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas.

§117.512. Compliance Schedule for Utility Electric Generation in East and Central Texas.

§117.520. Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas.

§117.524. Compliance Schedule for Cement Kilns.

§117.530. Compliance Schedule for Nitric Acid and Adipic Acid Manufacturing Sources.

§117.534. Compliance Schedule for Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources.

§117.570. Use of Emissions Credits for Compliance.

§117.571. Use of Emission Reductions Generated from the Texas Emissions Reduction Plan (TERP).

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SUBCHAPTER A. DEFINITIONS

30 TAC §117.10

STATUTORY AUTHORITY

The new section is proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed section implements Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.10. Definitions.

Unless specifically defined in the Texas Clean Air Act or Chapter 101 of this title (relating to General Air Quality Rules), the terms in this chapter have the meanings commonly used in the field of air pollution control. Additionally, the following meanings apply, unless the context clearly indicates otherwise. Additional definitions for terms used in this chapter are found in §3.2 and §101.1 of this title (relating to Definitions).

(1) Annual capacity factor--The total annual fuel consumed by a unit divided by the fuel that could be consumed by the unit if operated at its maximum rated capacity for 8,760 hours per year.

(2) Applicable ozone nonattainment area--The following areas, as designated under the 1990 Federal Clean Air Act Amendments.

(A) Beaumont-Port Arthur ozone nonattainment area--An area consisting of Hardin, Jefferson, and Orange Counties.

(B) Dallas-Fort Worth ozone nonattainment area--An area consisting of Collin, Dallas, Denton, and Tarrant Counties.

(C) Dallas-Fort Worth eight-hour ozone nonattainment area--An area consisting of Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties.

(D) Houston-Galveston-Brazoria ozone nonattainment area--An area consisting of Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties.

(3) Auxiliary steam boiler--Any combustion equipment within an electric power generating system, as defined in this section, that is used to produce steam for purposes other than generating electricity. An auxiliary steam boiler produces steam as a replacement for steam produced by another piece of equipment that is not operating due to planned or unplanned maintenance.

(4) Average activity level for fuel oil firing--The product of an electric utility unit's maximum rated capacity for fuel oil firing and the average annual capacity factor for fuel oil firing for the period from January 1, 1990, to December 31, 1993.

(5) Block one-hour average--An hourly average of data, collected starting at the beginning of each clock hour of the day and continuing until the start of the next clock hour.

(6) Boiler--Any combustion equipment fired with solid, liquid, and/or gaseous fuel used to produce steam or to heat water.

(7) Btu--British thermal unit.

(8) Chemical processing gas turbine--A gas turbine that vents its exhaust gases into the operating stream of a chemical process.

(9) Continuous emissions monitoring system (CEMS)--The total equipment necessary for the continuous determination and recordkeeping of process gas concentrations and emission rates in units of the applicable emission limitation.

(10) Daily--A calendar day starting at midnight and continuing until midnight the following day.

(11) Diesel engine--A compression-ignited two- or four-stroke engine that liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition.

(12) Duct burner--A unit that combusts fuel and that is placed in the exhaust duct from another unit (such as a stationary gas turbine, stationary internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases.

(13) Electric generating facility (EGF)--A unit that generates electric energy for compensation and is owned or operated by a person doing business in this state, including a municipal corporation, electric cooperative, or river authority.

(14) Electric power generating system--One electric power generating system consists of either:

(A) for the purposes of Subchapter C of this chapter (relating to Combustion Control at Major Utility Electric Generation Sources in Ozone Nonattainment Areas), all boilers, auxiliary steam boilers, and stationary gas turbines (including duct burners used in turbine exhaust ducts) at electric generating facility (EGF) accounts that generate electric energy for compensation; are owned or operated by an electric cooperative, independent power producer, municipality, river authority, public utility, or a Public Utility Commission of Texas regulated utility, or any of its successors; and are entirely located in one of the following ozone nonattainment areas:

(i) Beaumont-Port Arthur;

(ii) Dallas-Fort Worth;

(iii) Dallas-Fort Worth eight-hour; or

(iv) Houston-Galveston-Brazoria;

(B) for the purposes of Subchapter E, Division 1 of this chapter (relating to Utility Electric Generation in East and Central Texas), all boilers, auxiliary steam boilers, and stationary gas turbines at EGF accounts that generate electric energy for compensation; are owned or operated by an electric cooperative, independent power producer, municipality, river authority, or public utility, or any of its successors; and are located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, or Wharton County; or

(C) for the purposes of Subchapter B of this chapter (relating to Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Nonattainment Areas), all units in the Houston-Galveston-Brazoria ozone nonattainment area that generate electricity but do not meet the conditions specified in subparagraph (A) of this paragraph, including, but not limited to, cogeneration units and units owned by independent power producers.

(15) Emergency situation--As follows.

(A) An emergency situation is any of the following:

(i) an unforeseen electrical power failure from the serving electric power generating system;

(ii) the period of time that an emergency notice, as defined in *ERCOT Protocols, Section 2: Definitions and Acronyms* (April 25, 2006), issued by the Electric Reliability Council of Texas, Inc. (ERCOT) as specified in *ERCOT Protocols, Section 5: Dispatch* (April 26, 2006), is applicable to the serving electric power generating system. The emergency situation is considered to end upon expiration of the emergency notice issued by ERCOT;

(iii) an unforeseen failure of on-site electrical transmission equipment (e.g., a transformer);

(iv) an unforeseen failure of natural gas service;

(v) an unforeseen flood or fire, or a life-threatening situation; or

(vi) operation of emergency generators for Federal Aviation Administration licensed airports, military airports, or manned space flight control centers for the purposes of providing power in anticipation of a power failure due to severe storm activity.

(B) An emergency situation does not include operation for purposes of supplying power for distribution to the electric grid, operation for training purposes, or other foreseeable events.

(16) Functionally identical replacement--A unit that performs the same function as the existing unit that it replaces, with the condition that the unit replaced must be physically removed or rendered permanently inoperable before the unit replacing it is placed into service.

(17) Heat input--The chemical heat released due to fuel combustion in a unit, using the higher heating value of the fuel. This does not include the sensible heat of the incoming combustion air. In the case of carbon monoxide (CO) boilers, the heat input includes the enthalpy of all regenerator off-gases and the heat of combustion of the incoming CO and of the auxiliary fuel. The enthalpy change of the fluid catalytic cracking unit regenerator off-gases refers to the total heat content of the gas at the temperature it enters the CO boiler, referring to the heat content at 60 degrees Fahrenheit, as being zero.

(18) Heat treat furnace--A furnace that is used in the manufacturing, casting, or forging of metal to heat the metal so as to produce specific physical properties in that metal.

(19) High heat release rate--A ratio of boiler design heat input to firebox volume (as bounded by the front firebox wall where the burner is located, the firebox side waterwall, and extending to the level just below or in front of the first row of convection pass tubes) greater than or equal to 70,000 British thermal units per hour per cubic foot.

(20) Horsepower rating--The engine manufacturer's maximum continuous load rating at the lesser of the engine or driven equipment's maximum published continuous speed.

(21) Incinerator--As follows.

(A) For the purposes of this chapter, the term "incinerator" includes both of the following:

(i) a control device that combusts or oxidizes gases or vapors (e.g., thermal oxidizer, catalytic oxidizer, vapor combustor); and

(ii) an incinerator as defined in §101.1 of this title (relating to Definitions).

(B) The term "incinerator" does not apply to boilers or process heaters as defined in this section, or to flares as defined in §101.1 of this title.

(22) Industrial boiler--Any combustion equipment, not including utility or auxiliary steam boilers as defined in this section, fired with liquid, solid, or gaseous fuel, that is used to produce steam or to heat water.

(23) International Standards Organization (ISO) conditions--ISO standard conditions of 59 degrees Fahrenheit, 1.0 atmosphere, and 60% relative humidity.

(24) Large utility system--All boilers, auxiliary steam boilers, and stationary gas turbines that are located in the Dallas-Fort Worth or the Dallas-Fort Worth eight-hour ozone nonattainment area, and were part of one electric power generating system on January 1, 2000, that had a combined electric generating capacity equal to or greater than 500 megawatts.

(25) Lean-burn engine--A spark-ignited or compression-ignited, Otto cycle, diesel cycle, or two-stroke engine that is not capable of being operated with an exhaust stream oxygen concentration equal to or less than 0.5% by volume, as originally designed by the manufacturer.

(26) Low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit--An industrial, commercial, or institutional boiler; process heater; or gas turbine supplemental waste heat recovery unit with maximum rated capacity:

(A) greater than or equal to 40 million British thermal units per hour (MMBtu/hr), but less than 100 MMBtu/hr and an annual heat input less than or equal to 2.8 (10^{11}) British thermal units per year (Btu/yr), based on a rolling 12-month average; or

(B) greater than or equal to 100 MMBtu/hr and an annual heat input less than or equal to 2.2 (10^{11}) Btu/yr, based on a rolling 12-month average.

(27) Low annual capacity factor stationary gas turbine or stationary internal combustion engine--A stationary gas turbine or stationary internal combustion engine that is demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

(28) Low heat release rate--A ratio of boiler design heat input to firebox volume less than 70,000 British thermal units per hour per cubic foot.

(29) Major source--Any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit:

(A) at least 50 tons per year (tpy) of nitrogen oxides (NO_x) and is located in the Beaumont-Port Arthur ozone nonattainment area;

(B) at least 50 tpy of NO_x and is located in the Dallas-Fort Worth or Dallas-Fort Worth eight-hour ozone nonattainment area;

(C) at least 25 tpy of NO_x and is located in the Houston-Galveston-Brazoria ozone nonattainment area; or

(D) the amount specified in the major source definition contained in the Prevention of Significant Deterioration of Air Quality regulations promulgated by the United States Environmental Protection Agency in 40 Code of Federal Regulations §52.21 as amended June 3, 1993 (effective June 3, 1994), and is located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Comal, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Hays, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Red River, Robertson, Rusk, Titus, Travis, Victoria, or Wharton County.

(30) Maximum rated capacity--The maximum design heat input, expressed in million British thermal units per hour, unless:

(A) the unit is a boiler, utility boiler, or process heater operated above the maximum design heat input (as averaged over any one-hour period), in which case the maximum operated hourly rate must be used as the maximum rated capacity; or

(B) the unit is limited by operating restriction or permit condition to a lesser heat input, in which case the limiting condition must be used as the maximum rated capacity; or

(C) the unit is a stationary gas turbine, in which case the manufacturer's rated heat consumption at the International Standards Organization (ISO) conditions must be used as the maximum rated capacity, unless limited by permit condition to a lesser heat input, in which case the limiting condition must be used as the maximum rated capacity; or

(D) the unit is a stationary, internal combustion engine, in which case the manufacturer's rated heat consumption at Diesel Equipment Manufacturer's Association or ISO conditions must be used as the maximum rated capacity, unless limited by permit condition to a lesser heat input, in which case the limiting condition must be used as the maximum rated capacity.

(31) Megawatt (MW) rating--The continuous MW output rating or mechanical equivalent by a gas turbine manufacturer at International Standards Organization conditions, without consideration to the increase in gas turbine shaft output and/or the decrease in gas turbine fuel consumption by the addition of energy recovered from exhaust heat.

(32) Nitric acid--Nitric acid that is 30% to 100% in strength.

(33) Nitric acid production unit--Any source producing nitric acid by either the pressure or atmospheric pressure process.

(34) Nitrogen oxides (NO_x)--The sum of the nitric oxide and nitrogen dioxide in the flue gas or emission point, collectively expressed as nitrogen dioxide.

(35) Parts per million by volume (ppmv)--All ppmv emission specifications specified in this chapter are referenced on a dry basis. When required to adjust pollutant concentrations to a specified oxygen (O_2) correction basis, the following equation must be used.
Figure: 30 TAC §117.10(35)

(36) Peaking gas turbine or engine--A stationary gas turbine or engine used intermittently to produce energy on a demand basis.

(37) Plant-wide emission rate--The ratio of the total actual nitrogen oxides mass emissions rate discharged into the atmosphere from affected units at a major source when firing at their maximum rated capacity to the total maximum rated capacities for those units.

(38) Plant-wide emission specification--The ratio of the total allowable nitrogen oxides mass emissions rate dischargeable into the atmosphere from affected units at a major source when firing at their maximum rated capacity to the total maximum rated capacities for those units.

(39) Predictive emissions monitoring system (PEMS)--The total equipment necessary for the continuous determination and recordkeeping of process gas concentrations and emission rates using process or control device operating parameter measurements and a conversion equation or computer program to produce results in units of the applicable emission limitation.

(40) Process heater--Any combustion equipment fired with liquid and/or gaseous fuel that is used to transfer heat from combustion gases to a process fluid, superheated steam, or water for the purpose of heating the process fluid or causing a chemical reaction. The term "process heater" does not apply to any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment, or to boilers as defined in this section.

(41) Pyrolysis reactor--A unit that produces hydrocarbon products from the endothermic cracking of feedstocks such as ethane, propane, butane, and naphtha using combustion to provide indirect heating for the cracking process.

(42) Reheat furnace--A furnace that is used in the manufacturing, casting, or forging of metal to raise the temperature of that metal in the course of processing to a temperature suitable for hot working or shaping.

(43) Rich-burn engine--A spark-ignited, Otto cycle, four-stroke, naturally aspirated or turbocharged engine that is capable of being operated with an exhaust stream oxygen concentration equal to or less than 0.5% by volume, as originally designed by the manufacturer.

(44) Small utility system--All boilers, auxiliary steam boilers, and stationary gas turbines that are located in the Dallas-Fort Worth or the Dallas-Fort Worth eight-hour ozone nonattainment area, and were part of one electric power generating system on January 1, 2000, that had a combined electric generating capacity less than 500 megawatts.

(45) Stationary gas turbine--Any gas turbine system that is gas and/or liquid fuel fired with or without power augmentation. This unit is either attached to a foundation or is portable equipment operated at a specific minor or major source for more than 90 days in any 12-month period. Two or more gas turbines powering one shaft must be treated as one unit.

(46) Stationary internal combustion engine--A reciprocating engine that remains or will remain at a location (a single site at a building, structure, facility, or installation) for more than 12 consecutive months. Included in this definition is any engine that, by itself or in or on a piece of equipment, is portable, meaning designed to be and capable of being carried or moved from one location to another. Indicia of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine being replaced is included in calculating the consecutive residence time period. An engine is considered stationary if it is removed from one location for a period and then returned to the same location in an attempt to circumvent the consecutive residence time requirement. Nonroad engines, as defined in 40 Code of Federal Regulations §89.2, are not considered stationary for the purposes of this chapter.

(47) System-wide emission rate--The ratio of the total actual nitrogen oxides mass emissions rate discharged into the atmosphere from affected units in an electric power generating system or portion thereof located within a single ozone nonattainment area when firing at their maximum rated capacity to the total maximum rated capacities for those units. For fuel oil firing, average activity levels must be used in lieu of maximum rated capacities for the purpose of calculating the system-wide emission rate.

(48) System-wide emission specification--The ratio of the total allowable nitrogen oxides mass emissions rate dischargeable into the atmosphere from affected units in an electric power generating system or portion thereof located within a single ozone nonattainment area when firing at their maximum rated capacity to the total maximum rated capacities for those units. For fuel oil firing, average activity levels must be used in lieu of maximum rated capacities for the purpose of calculating the system-wide emission specification.

(49) Thirty-day rolling average--An average, calculated for each day that fuel is combusted in a unit, of all the hourly emissions data for the preceding 30 days that fuel was combusted in the unit.

(50) Twenty-four hour rolling average--An average, calculated for each hour that fuel is combusted (or acid is produced, for a nitric or adipic acid production unit), of all the hourly emissions data for the preceding 24 hours that fuel was combusted in the unit.

(51) Unit--A unit consists of either:

(A) for the purposes of §§117.105, 117.205, 117.305, 117.1005, 117.1105, and 117.1205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) and each requirement of this chapter associated with §§117.105, 117.205, 117.305, 117.1005, 117.1105, and 117.1205 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section;

(B) for the purposes of §§117.110, 117.210, 117.310, 117.1010, 117.1110, and 117.1210 of this title (relating to Emission Specifications for Attainment Demonstration) and each requirement of this chapter associated with §§117.110, 117.210, 117.310, 117.1010, 117.1110, and 117.1210 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section, or any other stationary source of nitrogen oxides (NO_x) at a major source, as defined in this section;

(C) for the purposes of §117.2010 and §117.2110 of this title (relating to Emission Specifications; and Emission Specifications for Eight-Hour Attainment Demonstration) and each requirement of this chapter associated with §117.2010 and §117.2110 of this title, any boiler, process heater, stationary gas turbine (including any duct burner in the turbine exhaust duct), or stationary internal combustion engine, as defined in this section;

(D) for the purposes of §117.3310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) and each requirement of this chapter associated with §117.3310 of this title, any stationary internal combustion engine, as defined in this section; or

(E) for the purposes of §117.410 and §117.1310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) and each requirement of this chapter associated with §117.410 and §117.1310 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section, or any other stationary source of NO_x at a major source, as defined in this section.

(52) Utility boiler--Any combustion equipment owned or operated by an electric cooperative, independent power producer, municipality, river authority, public utility, or Public Utility Commission of Texas regulated utility, fired with solid, liquid, and/or gaseous fuel, used to produce steam for the purpose of generating electricity. Stationary gas turbines, including any associated duct burners and unfired waste heat boilers, are not considered to be utility boilers.

(53) Wood--Wood, wood residue, bark, or any derivative fuel or residue thereof in any form, including, but not limited to, sawdust, sander dust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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SUBCHAPTER B. COMBUSTION CONTROL AT MAJOR INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL SOURCES IN OZONE NONATTAINMENT AREAS
DIVISION 1. BEAUMONT-PORT ARTHUR OZONE NONATTAINMENT AREA MAJOR SOURCES

30 TAC §§117.100, 117.103, 117.105, 117.110, 117.115, 117.123, 117.125, 117.130, 117.135, 117.140, 117.145, 117.150, 117.152, 117.154, 117.156

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.100. Applicability.

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

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

(2) stationary gas turbines; and

(3) stationary internal combustion engines.

§117.103. Exemptions.

(a) General exemptions. Units exempted from the provisions of this division (relating to Beaumont-Port Arthur Ozone Nonattainment Area Major Sources), except as specified in §§117.140(i), 117.145(f)(6), 117.150(c)(1), and 117.154(a)(5) of this title (relating to 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 §117.105(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;

(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);

(3) heat treating furnaces and reheat furnaces;

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

(5) dryers, kilns, or ovens used for drying, baking, cooking, calcining, and vitrifying;

(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;

(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;

(8) stationary internal combustion engines with a horsepower (hp) rating of less than 300 hp;

(9) any stationary diesel engine; and

(10) any cogeneration boiler that recovers waste heat from, or utilizes as a fuel source the tail gas from one or more carbon black reactors.

(b) RACT exemptions. Units exempted from §117.105 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 in 40 Code of Federal Regulations 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 stationary gas turbine with a MW rating less than 10.0 MW;

(7) 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;

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

(9) stationary internal combustion engines with a hp rating of less than 300 hp.

(c) Attainment demonstration exemptions. Units exempted from §117.110 of this title (relating to Emission Specifications for Attainment Demonstration) include units exempted from emission specifications in subsection (b)(2) - (5) and (8) of this section.

§117.105. 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 §§117.115, 117.123, 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 (NO_x) 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 NO_x 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 NO_x reduction projects permitted since November 15, 1990, and prior to June 9, 1993, that were solely for the purpose of making early NO_x reductions, are subject to the appropriate emission specification of subsection (b) of this section. The affected person shall document that the NO_x reduction project was solely for the purpose of obtaining early reductions, and include this documentation in the initial control plan required in §117.150 of this title (relating to Initial Control Plan Procedures).

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

(A) the NO_x 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 NO_x 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 §117.9000 of this title (relating to Compliance Schedule for Beaumont-Port Arthur 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 NO_x emission limit under a permit issued after June 9, 1993, in accordance with Chapter 116 of this title and the emission specifications of subsections (b) - (d) of this section apply. 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 §117.115 or §117.123 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 NO_x 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 §117.105(b)(6)

(7) for units that operate with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.140 of this title (relating to Continuous Demonstration of Compliance), the emission limits apply as:

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

(B) the mass of NO_x 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 limit in lb/MMBtu; and

(8) for units that do not operate with a NO_x CEMS or PEMS under §117.140 of this title, the emission limits 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 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 300 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 in 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 gas-fired, lean-burn, stationary, reciprocating internal combustion engine rated 300 hp or greater, NO_x emissions in excess of 3.0 g/hp-hr and CO emissions in excess of 3.0 g/hp-hr, either as:

(1) a block one-hour average limit; or

(2) a 30-day rolling average limit. The owner or operator shall ensure compliance with a 30-day rolling average using:

(A) a PEMS or CEMS under §117.140 of this title; or

(B) a monitoring system that:

(i) computes predicted emissions as a function of engine speed and torque using curves or equations supplied by the engine manufacturer or developed through engine testing, that:

(I) may be adjusted by engine testing; and

(II) must be shown to be consistent with the required initial and biennial compliance testing; and

(ii) monitors and records data representative of engine torque and speed at sufficient frequency to accurately compute the 30-day average NO_x.

(f) 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 specifications:

(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 specifications 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.

(g) 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 §117.115 or §117.123 of this title) ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(h) This section no longer applies to any gas-fired boiler or process heater after the appropriate compliance date(s) for emission specifications for attainment demonstration given in §117.9000(3) of this title.

§117.110. Emission Specifications for Attainment Demonstration.

(a) Nitrogen oxides (NO_x) emission specifications. No person shall allow the discharge into the atmosphere from any gas-fired boiler or process heater with a maximum rated capacity equal to or greater than 40 million British thermal units per hour in the Beaumont-Port Arthur ozone nonattainment area, emissions of NO_x in excess of the following, except as provided in subsection (d) of this section and §117.103(c) of this title (relating to Exemptions):

(1) boilers, 0.10 pounds per million British thermal units (lb/MMBtu) of heat input; and

(2) process heaters, 0.08 lb/MMBtu of heat input.

(b) NO_x averaging time. The emission specifications of subsection (a) of this section apply:

(1) if the unit is operated with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.140 of this title (relating to Continuous Demonstration of Compliance), either as:

(A) a rolling 30-day average period, in the units of the applicable standard;

(B) a block one-hour average, in the units of the applicable standard, or alternatively;

(C) a block one-hour average, in pounds per hour, for boilers and process heaters, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable NO_x emission specification in lb/MMBtu; and

(2) if the unit is not operated with a NO_x CEMS or PEMS under §117.140 of this title, a block one-hour average, in the units of the applicable standard. Alternatively for boilers and process heaters, the emission specifications may be applied in pounds per hour, as specified in paragraph (1)(C) of this subsection.

(c) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to NO_x emission specifications in subsection (a) of this section, emissions in excess of the following, except as provided in §117.125 of this title (relating to Alternative Case Specific Specifications) or paragraph (3) or (4) of this subsection.

(1) Carbon monoxide (CO) emissions must not exceed 400 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry basis (or alternatively, 3.0 grams per horsepower-hour for stationary internal combustion engines; or 775 ppmv at 7.0% O_2, dry basis for wood fuel-fired boilers or process heaters):

(A) on a rolling 24-hour averaging period, for units equipped with CEMS or PEMS for CO; and

(B) on a one-hour average, for units not equipped with CEMS or PEMS for CO.

(2) For units that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions must not exceed 10 ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines and gas-fired lean-burn engines; 0.0% O_2, dry, for fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents); 7.0% O_2, dry, for boilers and industrial furnaces units that were regulated as existing facilities in 40 Code of Federal Regulations Part 266, Subpart H (as was in effect on June 9, 1993) and for wood-fired boilers; and 3.0% O_2, dry, for all other units, based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(3) The correction of CO emissions to 3.0% O_2, dry basis, in paragraph (1) of this subsection does not apply to boilers and process heaters operating at less than 10% of maximum load and with stack O_2 in excess of 15% (i.e., hot-standby mode).

(4) The CO specifications in paragraph (1) of this subsection do not apply to stationary internal combustion engines subject to §117.105(e) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)).

(d) Compliance flexibility.

(1) An owner or operator may use any of the following alternative methods to comply with the NO_x emission specifications of this section:

(A) §117.115 of this title (relating to Alternative Plant-Wide Emission Specifications);

(B) §117.123 of this title (relating to Source Cap); or

(C) §117.9800 of this title (relating to Use of Emission Credits for Compliance).

(2) Section 117.125 of this title is not an applicable method of compliance with the NO_x emission specifications of this section.

(3) An owner or operator may petition the executive director for an alternative to the CO or ammonia specifications of this section in accordance with §117.125 of this title.

§117.115. Alternative Plant-Wide Emission Specifications.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission specifications of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or §117.110 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 §117.140 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 specification of §117.105 or §117.110 of this title at maximum rated capacity in calculating the plant-wide emission specification and shall assign to the unit the maximum allowable NO_x 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 specification of §117.105 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 specification of §117.105 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 §117.105 or §117.110 of this title in calculating the plant-wide emission specification and shall assign to the unit the maximum allowable NO_x 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 §117.105 of this title in calculating the plant-wide emission specification and shall assign to the unit the maximum allowable NO_x emission rate, calculated in accordance with subsection (a) of this section.

(f) Units exempted from emission specifications in accordance with §117.103(b) and (c) 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 §117.103(b) and (c) 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 emission specifications of §117.105 or §117.110 of this title apply to the opt-in units.

(3) The individual NO_x emission specification 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 §117.105(a) of this title, the specification of paragraph (4) of this subsection, or when applicable, subsection (i) of this section.

(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 §117.115(f) OPT-IN UNITS.
Figure: 30 TAC §117.115(f)(4)

(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 lowest of the emission specifications of §117.105 of this title, or when applicable, §117.110 of this title, or any applicable permit emission specification identified in subsection (i) of this section, as follows.

(1) For each affected boiler and process heater, the rate is determined by the following equation.
Figure: 30 TAC §117.115(g)(1)

(2) For each affected stationary internal combustion engine, the rate is determined by the following equation.
Figure: 30 TAC §117.115(g)(2)

(3) For each affected stationary gas turbine, the rate is determined by the following equations.
Figure: 30 TAC §117.115(g)(3)

(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 §117.105 of this title.

(A) Double application of the H_2 content multiplier using this paragraph and §117.105(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 §117.110 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 §117.110 of this title.

(i) When using this section for establishing alternative compliance with §117.110 of this title, the individual NO_x emission specification that is to be used in calculating the alternative plant-wide emission specifications is the lowest of the specification of §117.110 of this title, the actual emission rate as of September 1, 1997, and any applicable permit emission specification, in effect on September 10, 1993.

§117.123. Source Cap.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission specifications of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or §117.110 of this title (relating to Emission Specifications for Attainment Demonstration), by achieving equivalent NO_x 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 NO_x emission specifications of §117.105 or §117.110 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 §117.105 or §117.110 of this title, or §117.115 of this title (relating to 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 §117.123(b)(1)

(2) A maximum daily cap must be calculated for all emission units included in the source cap using the following equation.
Figure: 30 TAC §117.123(b)(2)

(3) Each emission unit included in the source cap is 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 §117.115(f) of this title in a source cap. For compliance with §117.105(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 §117.115(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 §117.115(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 NO_x 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 §117.140 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 §117.140 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 §117.115(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 §117.135(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 §117.135(e) of this title; and

(2) for each operating unit equipped with CEMS, either use a PEMS in accordance with §117.140 of this title, or the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117.135(e) of this title, to provide emissions compliance data during periods when the CEMS is off-line. The methods specified in 40 Code of Federal Regulations §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 NO_x emissions from each source and the total fuel usage for each unit and include a total NO_x 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 §117.145 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 §117.145 of this title.

(f) The owner or operator shall demonstrate initial compliance with the source cap in accordance with the schedule specified in §117.9000 of this title (relating to Compliance Schedule for Beaumont-Port Arthur Ozone Nonattainment Area Major Sources).

(g) For compliance with §117.105(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) For compliance with §117.105(e) or §117.110 of this title, a unit that has been permanently retired or decommissioned and rendered inoperable may be included in the source cap under the following conditions.

(1) Shutdowns must have occurred after September 10, 1993.

(2) The source cap emission limit for retired units is 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, 1997, and December 31, 1999, the actual heat input must be the average daily heat input for the continuous

time period that the unit was in service, consistent with the heat input used to represent the unit's emissions in the attainment demonstration modeling inventory. 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 been used for netting or offset purposes under the requirements of Chapter 116 of this title may not be included in the baseline for establishing the cap.

(i) 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 NO_x emission specifications of this division required by November 15, 1999.

(j) 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 §117.150 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 §117.152 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.

(k) 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 NO_x 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.

§117.125. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or the carbon monoxide (CO) or ammonia specifications of §117.110(c) of this title (relating to Emission Specifications for Attainment Demonstration), the executive director may approve emission specifications different from §117.105 of this title or the CO or ammonia specifications in §117.110(c) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) shall determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.105 or §117.110 of this title, as applicable; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through plant-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Beaumont-Port Arthur Ozone Nonattainment Area Major Sources).

§117.130. Operating Requirements.

(a) The owner or operator shall operate any unit subject to the emission specifications of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) in compliance with those specifications.

(b) The owner or operator shall operate any unit subject to the plant-wide emission specification of §117.115 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 specification and averaging period, is in accordance with the list approved by the executive director pursuant to §117.152 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 §117.123 of this title (relating to Source Cap) in compliance with those limitations.

(d) All units subject to §§117.105, 117.110(a), 117.115, or 117.123 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Emission Specifications for Attainment Demonstration; Alternative Plant-Wide Emission Specifications; and Source Cap) 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 specifications.

(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).

§117.135. Initial Demonstration of Compliance.

(a) The owner or operator of all units that are subject to the emission specifications of this division (relating to Beaumont-Port Arthur Ozone Nonattainment Area Major Sources) shall test the units as follows.

(1) The units 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 NO_x 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 §117.115(f) of this title (relating to Alternative Plant-Wide Emission Specifications); or

(B) the source cap as defined in §117.123(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 §117.9000 of this title (relating to Compliance Schedule for Beaumont-Port Arthur 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 emission specifications of this division. Test results must be reported in the units of the applicable emission specifications and averaging periods.

(c) Any continuous emissions monitoring system (CEMS) or any predictive emissions monitoring system (PEMS) required by §117.140 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 standards specified in 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) of this section 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 emission specifications 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 emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.140 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 §117.123 of this title, a rolling 30-day average of total daily pounds of NO_x emissions from the units are monitored (or calculated in accordance with §117.123(c) of this title) for 30 successive source 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 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).

§117.140. 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 ±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 ±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) Totalizing fuel flow meters are required for the following units that are subject to §117.105 or §117.110 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); and Emission Specifications for Attainment Demonstration) and for stationary gas turbines that are exempt under §117.103(b)(6) of this title (relating to Exemptions):

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

(i) boilers;

(ii) process heaters; and

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

(B) stationary, reciprocating internal combustion engines not exempt by §117.103(a)(6), (a)(8), (b)(8), or (b)(9) of this title; and

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

(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 (e) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (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 (e) 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 (f) of this section.

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

(A) units listed in §117.103(b)(3) - (5) and (7) - (9) of this title;

(B) process heaters operating with a carbon dioxide CEMS for diluent monitoring under subsection (e) 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 (e) 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 (e) 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) boilers and process heaters that are vented through a common stack and the total rated heat input from the units combined is greater than or equal to 250 MMBtu/hr and the annual heat input combined is greater than $2.2(10^{11})$ Btu/yr;

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

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

(F) units that the owner or operator elects to comply with the NO_x emission specifications of §117.105 or §117.110(a) of this title using a pounds per million British thermal unit (lb/MMBtu) limit on a 30-day rolling average.

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

(A) for purposes of §117.105 or §117.110(a) of this title, units listed §117.103(b)(3) - (5) and (7) - (9) of this title; and

(B) units subject to the NO_x 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 NO_x monitor is off-line:

(A) if the NO_x 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 §117.1040(d) of this title (relating to Continuous Demonstration of Compliance);

(C) if the NO_x 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) if the methods specified in subparagraphs (A) - (C) of this paragraph are not used, the owner or operator shall use the maximum block one-hour emission rate as measured during the initial demonstration of compliance required in §117.135(f) of this title (relating to Initial Demonstration of Compliance).

(d) Carbon monoxide (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).

(e) CEMS requirements. The owner or operator of any CEMS used to meet a pollutant monitoring requirement of this section shall comply with the requirements of §117.8100(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources).

(f) 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 Beaumont-Port Arthur Ozone Nonattainment Area Major Sources).

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

(g) Engine monitoring. The owner or operator of any stationary gas engine subject to the emission specifications of this division shall stack test engine NO_x and CO emissions as specified in §117.8140(a) of this title (relating to Emission Monitoring for Engines).

(h) 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 §117.105 of this title or §117.115 of this title (relating to 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 (d) 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 ±5.0%;

(B) the steam-to-fuel or water-to-fuel ratio monitoring data must be used for demonstrating continuous compliance with the applicable emission specification of §117.105 or §117.115 of this title; and

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

(i) Run time meters. The owner or operator of any stationary gas turbine or stationary internal combustion engine claimed exempt using the exemption of §117.103(a)(6)(D), (b)(2), or (b)(8) 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.

(j) Hydrogen (H_2) monitoring. The owner or operator claiming the H_2 multiplier of §117.105(b)(6) or §117.115(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.

(k) Data used for compliance. After the initial demonstration of compliance required by §117.135 of this title, the methods required in this section must be used to determine compliance with the emission specifications of §117.105 or §117.110(a) 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 specifications.

(l) Enforcement of NO_x RACT limits. If compliance with §117.105 of this title is selected, no unit subject to §117.105 of this title may be operated at an emission rate higher than that allowed by the emission specifications of §117.105 of this title. If compliance with §117.115 of this title is selected, no unit subject to §117.115 of this title may be operated at an emission rate higher than that approved by the executive director under §117.152(b) of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology).

(m) Loss of NO_x 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 §117.103(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.

§117.145. 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, 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 §117.135 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

§117.140 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 §117.135 of this title and any CEMS or PEMS RATA conducted under §117.140 of this title:

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

(2) not later than the compliance schedule specified in §117.9000 of this title (relating to Compliance Schedule for Beaumont-Port Arthur 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 §117.140 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 Beaumont-Port Arthur Ozone Nonattainment Area Major Sources) and the 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 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 §117.140(h)(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 §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)); and

(B) for units complying with §117.123 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 the emission specifications in §§117.105, 117.110, or 117.115 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 §117.130(d)(7) of this title (relating to Operating Requirements) and the biennial emission testing required for demonstration of emissions compliance in accordance with §117.140(g) 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, United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction. The records must include:

(1) for each unit subject to §117.140(a) of this title, records of annual fuel usage;

(2) for each unit using a CEMS or PEMS in accordance with §117.140 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; or

(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) pounds per million British thermal units heat input; 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) §117.130(d)(7) of this title; and

(ii) §117.140(g) 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 §117.140(h) 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 §117.140(j) 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 §117.103(a)(6)(D) 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 §117.103(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 §117.140(d) 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; and

(9) records of the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.135 of this title.

§117.150. Initial Control Plan Procedures.

(a) The owner or operator of any major source of nitrogen oxides (NO_x) shall submit, for the approval of the executive director, an initial control plan for installation of NO_x 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 NO_x 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 §117.135(e) or (f) of this title (relating to Initial Demonstration of Compliance) for NO_x, 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 §117.135(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 in 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 300 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 300 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 §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), §117.115 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117.123 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 §117.105 or §117.115 of this title and the rule basis for the claimed exemption;

(4) identification of the election to use individual emission specifications as specified in §117.105 of this title, the plant-wide emission specification as specified in §117.115 of this title, or the source cap emission limit as specified in §117.123 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 §117.130(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 shut down and rendered inoperable after November 15, 1990, as a result of compliance with §117.105 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 Beaumont-Port Arthur 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 §117.140(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 NO_x reduction projects as specified in §117.105(a)(1)(B) of this title, documentation that such projects were undertaken solely for the purpose of obtaining early NO_x reductions; and

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

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

(a) The owner or operator of units listed in §117.100 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)). The report must include a list of the units listed in §117.100 of this title, showing:

(1) the NO_x emission specification resulting from application of §117.105 of this title for each non-exempt unit;

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

(A) §117.105 of this title;

(B) §117.115 of this title (relating to Alternative Plant-Wide Emission Specifications);

(C) §117.123 of this title (relating to Source Cap);

(D) §117.125 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 NO_x control for each unit;

(4) the emissions measured by testing required in §117.135 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 §117.135 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 Beaumont-Port Arthur 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 300 horsepower.

(b) For sources complying with §117.115 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 §117.115(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 §117.115 of this title.

(c) For sources complying with §117.123 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;

(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 §117.123(g) and (h) of this title.

(d) The report must be submitted by the applicable date specified for final control plans in §117.9000 of this title (relating to Compliance Schedule for Beaumont-Port Arthur 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 §117.9000 of this title.

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

(a) The owner or operator of units listed in §117.110 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 §117.110 of this title. The report must include:

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

(A) §117.110 of this title;

(B) §117.115 of this title (relating to Alternative Plant-Wide Emission Specifications);

(C) §117.123 of this title (relating to Source Cap); or

(D) §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 §117.135 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 §117.135 of this title that is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any unit with a claimed exemption from the emission specification of §117.110 of this title.

(b) For sources complying with §117.123 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;

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

(A) the average daily heat input, H_i, specified in §117.123(b)(1) of this title;

(B) the maximum daily heat input, H_{mi}, specified in §117.123(b)(1) of this title;

(C) the method of monitoring emissions; and

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

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

(c) The report must be submitted to the executive director by the applicable date specified for final control plans in §117.9000 of this title (relating to Compliance Schedule for Beaumont-Port Arthur 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 source cap rolling 30-day average emission limit, according to the applicable schedule given in §117.9000 of this title.

§117.156. 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 emission specifications and the final compliance dates of this division (relating to Beaumont-Port Arthur Ozone Nonattainment Area Major Sources).

(1) For sources complying with §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), §117.110 of this title (relating to Emission Specifications for Attainment Demonstration), or §117.115 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 §117.123 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 is subject to the review and approval of the executive director.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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DIVISION 2. DALLAS-FORT WORTH OZONE NONATTAINMENT AREA MAJOR SOURCES

30 TAC §§117.200, 117.203, 117.205, 117.210, 117.215, 117.223, 117.225, 117.230, 117.235, 117.240, 117.245, 117.252, 117.254, 117.256

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.200. Applicability.

(a) The provisions of this division (relating to Dallas-Fort Worth Ozone Nonattainment Area Major Sources), apply to the following units located at any major stationary source of nitrogen oxides (NO_x) located within the Dallas-Fort Worth ozone nonattainment area:

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

(2) stationary gas turbines; and

(3) stationary internal combustion engines.

(b) This division no longer applies to any units that are subject to the emission specifications in §117.410 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) located at any major stationary source of NO_x located within Collin, Dallas, Denton, and Tarrant Counties after the appropriate compliance date(s) specified in §117.9030 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources).

§117.203. Exemptions.

(a) General exemptions. Units exempted from the provisions of this division (relating to Dallas-Fort Worth Ozone Nonattainment Area Major Sources), except as specified in §§117.240(i), 117.245(f)(6), and 117.254(a)(5) of this title (relating to Continuous Demonstration of Compliance; Notification, Recordkeeping, and Reporting Requirements; 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 §117.205(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;

(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);

(3) heat treating furnaces and reheat furnaces;

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

(5) dryers, kilns, or ovens used for drying, baking, cooking, calcining, and vitrifying;

(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;

(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;

(8) stationary internal combustion engines with a horsepower (hp) rating of less than 300 hp; and

(9) any stationary diesel engine.

(b) RACT exemptions. Units exempted from the emissions specifications of §117.205 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 in 40 Code of Federal Regulations 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 300 hp.

(c) Attainment demonstration exemptions. Units exempted from the emissions specifications of §117.210 of this title (relating to Emission Specifications for Attainment Demonstration) include units exempted from emission specifications in subsection (b)(2) - (5) and (9) of this section.

§117.205. 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 §§117.215, 117.223, 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 (NO_x) 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 NO_x 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 NO_x reduction projects permitted since November 15, 1990, and prior to June 9, 1993, that were solely for the purpose of making early NO_x reductions, are subject to the appropriate emission specification of subsection (b) of this section.

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

(A) the NO_x 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 NO_x 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 §117.9010 of this title (relating to Compliance Schedule for Dallas-Fort Worth 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 NO_x 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 apply. 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 §117.215 or §117.223 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 NO_x 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 specification calculated as the heat input weighted sum of the applicable emission specifications 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

specifications contained in paragraph (1) or (2) of this subsection to calculate an emission specification for each rolling 30-day period: Figure: 30 TAC §117.205(b)(6)

(7) for units that operate with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.240 of this title (relating to Continuous Demonstration of Compliance), the emission limits apply as:

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

(B) the mass of NO_x 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 limit in (lb/MMBtu); and

(8) for units that do not operate with a NO_x CEMS or PEMS under §117.240 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 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 300 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 in 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 specifications:

(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 specifications 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 §117.215 or §117.223 of this title) ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

§117.210. Emission Specifications for Attainment Demonstration.

(a) Emission specifications. No person shall allow the discharge into the atmosphere emissions in excess of the following emission specifications, except as provided in subsection (d) of this section and §117.203(c) of this title (relating to Exemptions).

(1) Gas-fired boilers with a maximum rated capacity equal to or greater than 40 million British thermal units per hour, must comply with 30 parts per million by volume (ppmv) nitrogen oxides (NO_x), at 3.0% oxygen (O_2), dry basis, according to the applicable schedule in §117.9010 of this title (relating to Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Major Sources).

(2) Gas-fired and dual-fuel, lean-burn, stationary reciprocating internal combustion engines rated 300 horsepower (hp) or greater, must comply with a NO_x emission specification of 2.0 grams per horsepower-hour (g/hp-hr) and a carbon monoxide (CO) emission specification of 3.0 g/hp-hr, according to the applicable schedule in §117.9010 of this title.

(b) NO_x averaging time. The emission specifications of subsection (a) of this section apply:

(1) if the unit is operated with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.240 of this title (relating to Continuous Demonstration of Compliance), either as:

(A) a rolling 30-day average period, in the units of the applicable standard;

(B) a block one-hour average, in the units of the applicable standard, or alternatively;

(C) a block one-hour average, in pounds per hour, for boilers and process heaters, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in pounds per million British thermal units; and

(2) if the unit is not operated with a NO_x CEMS or PEMS under §117.240 of this title, a block one-hour average, in the units of the applicable standard. Alternatively for boilers and process heaters, the emission limits may be applied in pounds per hour, as specified in paragraph (1)(C) of this subsection.

(c) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to NO_x emission specifications in subsection (a) of this section, emissions in excess of the following, except as provided in §117.225 of this title (relating to Alternative Case Specific Specifications) or paragraph (3) or (4) of this subsection.

(1) CO emissions must not exceed 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines; or 775 ppmv at 7.0% O_2, dry basis for wood fuel-fired boilers or process heaters):

(A) on a rolling 24-hour averaging period, for units equipped with CEMS or PEMS for CO; and

(B) on a one-hour average, for units not equipped with CEMS or PEMS for CO.

(2) For units that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions must not exceed 10 ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines and gas-fired lean-burn engines; 7.0% O_2, dry, for wood-fired boilers; and 3.0% O_2, dry, for all other units, based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(3) The correction of CO emissions to 3.0% O_2, dry basis, in paragraph (1) of this subsection does not apply to boilers and process heaters operating at less than 10% of maximum load and with stack O_2 in excess of 15% (i.e., hot-standby mode).

(4) The CO specifications in paragraph (1) of this subsection do not apply to stationary internal combustion engines subject to subsection (a)(2) of this section.

(d) Compliance flexibility.

(1) An owner or operator may use any of the following alternative methods to comply with the NO_x emission specifications of this section:

(A) §117.215 of this title (relating to Alternative Plant-Wide Emission Specifications);

(B) §117.223 of this title (relating to Source Cap); or

(C) §117.9800 of this title (relating to Use of Emission Credits for Compliance).

(2) Section 117.225 of this title is not an applicable method of compliance with the NO_x emission specifications of this section.

(3) An owner or operator may petition the executive director for an alternative to the CO or ammonia emission specifications of this section in accordance with §117.225 of this title.

§117.215. Alternative Plant-Wide Emission Specifications.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or §117.210 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 §117.240 of this title (relating to Continuous Demonstration of Compliance), the emission limits apply in:

(A) the units of the applicable standard (the mass of NO_x emitted per unit of energy input (pound 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 §117.205 or §117.210 of this title at maximum rated capacity in calculating the plant-wide emission specification and shall assign to the unit the maximum allowable NO_x 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 specification of §117.205 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 specification of §117.205 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 §117.205 or §117.210 of this title in calculating the plant-wide emission specification and shall assign to the unit the maximum allowable NO_x 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 §117.205 of this title in calculating the plant-wide emission specification and shall assign to the unit the maximum allowable NO_x emission rate, calculated in accordance with subsection (a) of this section.

(f) Units exempted from emission specifications in accordance with §117.203(b) and (c) 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 §117.203(b) and (c) 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 emission specifications of §117.205 or §117.210 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 §117.205(a) of this title, the specification of paragraph (4) of this subsection, or when applicable, subsection (i) of this section.

(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 §117.215(f) OPT-IN UNITS.
Figure: 30 TAC §117.215(f)(4)

(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 lowest of the emission specifications of §117.205 of this title, or when applicable, §117.210 of this title, or any applicable permit emission specification identified in subsection (i) of this section, as follows.

(1) For each affected boiler and process heater, the rate is determined by the following equation.
Figure: 30 TAC §117.215(g)(1)

(2) For each affected stationary internal combustion engine, the rate is determined by the following equation.
Figure: 30 TAC §117.215(g)(2)

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

Figure: 30 TAC §117.215(g)(3)

(4) Each affected gas-fired boiler and process heater firing gaseous fuel that contains more than 50% hydrogen (H_2) by volume, over 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 §117.205 of this title.

(A) Double application of the H_2 content multiplier using this paragraph and §117.205(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 §117.210 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 §117.210 of this title.

(i) When using this section for establishing alternative compliance with §117.210 of this title, the individual NO_x emission limit that is to be used in calculating the alternative plant-wide emission specifications is the lowest of the specification of §117.210 of this title, the actual emission rate as of September 1, 1997, and any applicable permit emission specification in effect on September 1, 1997.

§117.223. Source Cap.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or §117.210 of this title (relating to Emission Specifications for Attainment Demonstration), by achieving equivalent NO_x 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 NO_x emission limits of §117.205 or §117.210 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 §§117.205, 117.210, or 117.215 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Emission Specifications for Attainment Demonstration; 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 §117.223(b)(1)

(2) A maximum daily cap must be calculated for all emission units included in the source cap using the following equation.
Figure: 30 TAC §117.223(b)(2)

(3) Each emission unit included in the source cap is 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 §117.215(f) of this title in a source cap. For compliance with §117.205(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 §117.215(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 §117.215(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 NO_x 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 §117.240 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 §117.240 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 §117.215(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 §117.235(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 §117.235(e) of this title; and

(2) for each operating unit equipped with CEMS, either use a PEMS in accordance with §117.240 of this title, or the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117.235(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 NO_x emissions from each source and the total fuel usage for each unit and include a total NO_x 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

§117.245 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 §117.245 of this title.

(f) The owner or operator shall demonstrate initial compliance with the source cap in accordance with the schedule specified in §117.9010 of this title (relating to Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Major Sources).

(g) For compliance with §117.205(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) For compliance with §117.210 of this title, a unit that has been permanently retired or decommissioned and rendered inoperable may be included in the source cap under the following conditions.

(1) Shutdowns must have occurred after September 1, 1997.

(2) The source cap emission limit for retired units is 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, 1997, and December 31, 1999, the actual heat input must be the average daily heat input for the continuous time period that the unit was in service, consistent with the heat input used to represent the unit's emissions in the attainment demonstration modeling inventory. 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 been used for netting or offset purposes under the requirements of Chapter 116 of this title may not be included in the baseline for establishing the cap.

(i) A unit that has been shut down and rendered inoperable after June 9, 1993, but not permanently retired, should be identified in the final control plan and may be included in the source cap to comply with the NO_x emission specifications of this division applicable in the Dallas-Fort Worth ozone nonattainment area, required by March 31, 2001.

(j) An owner or operator who chooses to use the source cap option shall include in the final control plan, if required to be filed under §117.252 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology), a plan for initial compliance. The owner or operator shall include in the final 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 final 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 §117.252 of this title the information necessary under this section to demonstrate initial compliance with the source cap.

(k) 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 emission events, as defined in §101.1 of this title (relating to Definitions), must be calculated from the NO_x 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.

§117.225. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or the carbon monoxide (CO) or ammonia specifications of §117.210(c) of this title (relating to Emission Specifications for Attainment Demonstration), the executive director may approve emission specifications different from §117.205 of this title or the CO or ammonia specifications in §117.210(c) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) shall determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.205 or §117.210 of this title, as applicable; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through plant-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Dallas-Fort Worth Ozone Nonattainment Area Major Sources).

§117.230. Operating Requirements.

(a) The owner or operator shall operate any unit subject to the emission specifications of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) in compliance with those specifications.

(b) The owner or operator shall operate any unit subject to the plant-wide emission specification of §117.215 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 §117.252 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 §117.223 of this title (relating to Source Cap) in compliance with those limitations.

(d) All units subject to the emission limitations of §§117.205, 117.210(a), 117.215, or 117.223 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Emission Specifications for Attainment Demonstration; Alternative Plant-Wide Emission Specifications; and Source Cap) 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).

§117.235. Initial Demonstration of Compliance.

(a) The owner or operator of all units that are subject to the emission specifications of this division (relating to Dallas-Fort Worth Ozone Nonattainment Area Major Sources) shall test the units as follows.

(1) The units 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 NO_x 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 §117.215(f) of this title (relating to Alternative Plant-Wide Emission Specifications); or

(B) the source cap as defined in §117.223(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 §117.9010 of this title (relating to Compliance Schedule for Dallas-Fort Worth 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 emission specifications of this division. Test results must be reported in the units of the applicable emission specifications and averaging periods.

(c) Any continuous emissions monitoring system (CEMS) or any predictive emissions monitoring system (PEMS) required by §117.240 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, at 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 standards specified in 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 emission specifications 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 emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.240 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 pound 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 §117.223 of this title, a rolling 30-day average of total daily pounds of NO_x emissions from the units are monitored (or calculated in accordance with §117.223(c) of this title) for 30 successive source 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 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).

§117.240. 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 ±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 ±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) Totalizing fuel flow meters are required for the following units that are subject to §117.205 or §117.210 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); and Emission Specifications for Attainment Demonstration), and for stationary gas turbines that are exempt under §117.203(b)(7) of this title (relating to Exemptions):

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

(i) boilers;

(ii) process heaters; and

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

(B) stationary, reciprocating internal combustion engines not exempt by §117.203(a)(6) or (8) of this title, or §117.203(b)(9) or (10) of this title; and

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

(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 (e) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (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 (e) of this section may use a single totalizing fuel flow meter.

(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 (f) of this section.

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

(A) units listed in §117.203(b)(3) - (5) and (8) - (10) of this title;

(B) process heaters operating with a carbon dioxide CEMS for diluent monitoring under subsection (e) 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 (e) 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 (e) 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; and

(E) units that the owner or operator elects to comply with the NO_x emission specifications of §117.205 or §117.210(a) of this title using a pound per million British thermal units (lb/MMBtu) limit on a 30-day rolling average.

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

(A) for purposes of §117.205 or §117.210(a) of this title, units listed in §117.203(b)(3) - (5) and (8) - (10) of this title; and

(B) units subject to the NO_x 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 NO_x monitor is off-line:

(A) if the NO_x 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 §117.1140(d) of this title (relating to Continuous Demonstration of Compliance);

(C) if the NO_x 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) if the methods specified in subparagraphs (A) - (C) of this paragraph are not used, the owner or operator shall use the maximum block one-hour emission rate as measured during the initial demonstration of compliance required in §117.235(f) of this title (relating to Initial Demonstration of Compliance).

(d) Carbon monoxide (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).

(e) CEMS requirements. The owner or operator of any CEMS used to meet a pollutant monitoring requirement of this section shall comply with the requirements of §117.8100(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources).

(f) 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 Dallas-Fort Worth Ozone Nonattainment Area Major Sources).

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

(g) Engine monitoring. The owner or operator of any stationary gas engine subject to the emission specifications of this division shall stack test engine NO_x and CO emissions as specified in §117.8140(a) of this title (relating to Emission Monitoring for Engines).

(h) 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 §117.205 or §117.215 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 (d) 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 ±5.0%;

(B) the steam-to-fuel or water-to-fuel ratio monitoring data must be used for demonstrating continuous compliance with the applicable emission specification of §117.205 or §117.215 of this title; and

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

(i) Run time meters. The owner or operator of any stationary gas turbine or stationary internal combustion engine claimed exempt using the exemption of §117.203(a)(6)(D), (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.

(j) Hydrogen (H_2) monitoring. The owner or operator claiming the H_2 multiplier of §117.205(b)(6) or §117.215(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.

(k) Data used for compliance. After the initial demonstration of compliance required by §117.235 of this title, the methods required in this section must be used to determine compliance with the emission specifications of §117.205 or §117.210(a) 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.

(l) Enforcement of NO_x RACT limits. If compliance with §117.205 of this title is selected, no unit subject to §117.205 of this title may be operated at an emission rate higher than that allowed by the emission specifications of §117.205 of this title. If compliance with §117.215 of this title is selected, no unit subject to §117.215 of this title may be operated at an emission rate higher than that approved by the executive director under §117.252(b) of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology).

(m) Loss of NO_x 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 §117.203(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 must be subject to the review and approval of the executive director.

§117.245. 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, 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 §117.235 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 §117.240 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 §117.235 of this title and any CEMS or PEMS RATA conducted under §117.240 of this title:

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

(2) not later than the compliance schedule specified in §117.9010 of this title (relating to Compliance Schedule for Dallas-Fort Worth 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 §117.240 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 Dallas-Fort Worth Ozone Nonattainment Area Major Sources) and the 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 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 §117.240(h)(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 §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)); and

(B) for units complying with §117.223 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 the emission specifications in §117.205, §117.210 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT) and Emission Specifications for Attainment Demonstration), or §117.215 of this title (relating to 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 §117.230(d)(7) of this title (relating to Operating Requirements) and the biennial emission testing required for demonstration of emissions compliance in accordance with §117.240(g) 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 §117.240(a) of this title, records of annual fuel usage;

(2) for each unit using a CEMS or PEMS in accordance with §117.240 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; or

(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 heat input; 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) §117.230(d)(7) of this title; and

(ii) §117.240(g) 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 §117.240(h) 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 §117.240(j) 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 §117.203(a)(6)(D) 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 §117.203(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 §117.240(d) 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; and

(9) records of the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.235 of this title.

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

(a) The owner or operator of units listed in §117.200 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)). The report must include a list of the units listed in §117.200 of this title, showing:

(1) the NO_x emission specification resulting from application of §117.205 of this title for each non-exempt unit;

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

(A) §117.205 of this title;

(B) §117.215 of this title (relating to Alternative Plant-Wide Emission Specifications);

(C) §117.223 of this title (relating to Source Cap);

(D) §117.225 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 control of NO_x emissions for each unit;

(4) the emissions measured by testing required in §117.235 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 §117.235 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 Dallas-Fort Worth 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 300 horsepower.

(b) For sources complying with §117.215 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 §117.215(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 §117.215 of this title.

(c) For sources complying with §117.223 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;

(D) the method of monitoring emissions; and

(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 §117.223(g) and (h) of this title.

(d) The report must be submitted by the applicable date specified for final control plans in §117.9010 of this title (relating to Compliance Schedule for Dallas-Fort Worth 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 §117.9010 of this title.

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

(a) The owner or operator of units listed in §117.210 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 §117.210 of this title. The report must include:

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

(A) §117.210 of this title;

(B) §117.215 of this title (relating to Alternative Plant-Wide Emission Specifications);

(C) §117.223 of this title (relating to Source Cap); or

(D) §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 §117.235 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 §117.235 of this title that is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any unit with a claimed exemption from the emission specification of §117.210 of this title.

(b) For sources complying with §117.223 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;

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

(A) the average daily heat input, H_i, specified in §117.223(b)(1) of this title;

(B) the maximum daily heat input, H_{mi}, specified in §117.223(b)(1) of this title;

(C) the method of monitoring emissions; and

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

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

(c) The report must be submitted to the executive director by the applicable date specified for final control plans in §117.9010 of this title (relating to Compliance Schedule for Dallas-Fort Worth 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 source cap rolling 30-day average emission limit, according to the applicable schedule given in §117.9010 of this title.

§117.256. 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 emission specifications and the final compliance dates of this division (relating to Dallas-Fort Worth Ozone Nonattainment Area Major Sources).

(1) For sources complying with §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), §117.210 of this title (relating to Emission Specifications for Attainment Demonstration), or §117.215 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 §117.223 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 is subject to the review and approval of the executive director.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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DIVISION 3. HOUSTON-GALVESTON-BRAZORIA OZONE NONATTAINMENT AREA MAJOR SOURCES

30 TAC §§117.300, 117.303, 117.305, 117.310, 117.315, 117.320, 117.323, 117.325, 117.330, 117.335, 117.340, 117.345, 117.350, 117.352, 117.354, 117.356

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 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 nonroad 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 (NO_x) 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 NO_x 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 NO_x reduction projects permitted since November 15, 1990, and prior to June 9, 1993, that were solely for the purpose of making early NO_x reductions, are subject to the appropriate emission specification of subsection (b) of this section. The affected person shall document that the NO_x 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 NO_x emission limitations under this section from existing permit limits, the following procedure must be used:

(A) the NO_x 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 NO_x 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 NO_x 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 NO_x 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)

(7) for units that operate with a NO_x 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 NO_x emitted per unit of energy input (lb/MMBtu), on a rolling 30-day average period; or

(B) the mass of NO_x 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 NO_x 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% NO_x reduction of the exhaust concentration used to calculate the June - August 1997 daily NO_x 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 NO_x 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 NO_x 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% NO_x 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 NO_x emissions;

(16) incinerators, either of the following:

(A) 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; 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) NO_x 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) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to subsection (a) of this section, emissions in excess of the following, except as provided in §117.325 of this title (relating to Alternative Case Specific Specifications) or paragraph (3) or (4) of this subsection.

(1) CO emissions must not exceed 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines; or 775 ppmv at 7.0% O_2, dry basis for wood fuel-fired boilers or process heaters):

(A) on a rolling 24-hour averaging period, for units equipped with CEMS or PEMS for CO; and

(B) on a one-hour average, for units not equipped with CEMS or PEMS for CO.

(2) For units that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions must not exceed 10 ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), gas-fired lean-burn engines, and lightweight aggregate kilns; 0.0% O_2, dry, for fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents); 7.0% O_2, dry, for BIF units that were regulated as existing facilities in 40 CFR Part 266, Subpart H (as was in effect on June 9, 1993), wood-fired boilers, and incinerators; and 3.0% O_2, dry, for all other units, based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(3) The correction of CO emissions to 3.0% O_2, dry basis, in paragraph (1) of this subsection does not apply to the following units:

(A) lightweight aggregate kilns; and

(B) boilers and process heaters operating at less than 10% of maximum load and with stack O_2 in excess of 15% (i.e., hot-standby mode).

(4) The CO limits in paragraph (1) of this subsection do not apply to the following units:

(A) BIF units that were regulated as existing facilities in 40 CFR Part 266, Subpart H (as was in effect on June 9, 1993) and that are subject to subsection (a)(3) of this section; and

(B) incinerators subject to the CO limits of one of the following:

(i) §111.121 of this title (relating to Single-, Dual-, and Multiple-Chamber Incinerators);

(ii) §113.2072 of this title (relating to Emission Limits) for hospital/medical/infectious waste incinerators; or

(iii) 40 CFR Part 264 or 265, Subpart O, for hazardous waste incinerators.

(d) Compliance flexibility.

(1) Section 117.325 of this title is not an applicable method of compliance with the NO_x 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 NO_x 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 NO_x 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 NO_x 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 (NO_x) 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 NO_x 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 NO_x 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 NO_x 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)

(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)

(2) For each affected stationary internal combustion engine, the rate is determined by the following equation.
Figure: 30 TAC §117.315(g)(2)

(3) For each affected stationary gas turbine, the rate is determined by the following equations.
Figure: 30 TAC §117.315(g)(3)

(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)

(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)

(3) A maximum daily cap must be calculated using the following equation.
Figure: 30 TAC §117.320(c)(3)

(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 NO_x emissions and fuel usage from each EGF and summations of total NO_x 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 NO_x emission rate measured by the NO_x monitor, if operating properly. If the NO_x monitor is not operating properly, the substitute data procedures identified in subsection (e) of this section must be used. If neither the NO_x 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 (NO_x) emission limits of §117.305 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) by achieving equivalent NO_x 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 NO_x 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)

(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)

(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 NO_x 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 NO_x emissions from each source and the total fuel usage for each unit and include a total NO_x 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 NO_x 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 NO_x 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.

§117.325. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.305 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or the carbon monoxide (CO) or ammonia specifications of §117.310(c) of this title (relating to Emission Specifications for Attainment Demonstration), the executive director may approve emission specifications different from §117.305 of this title or the CO or ammonia specifications in §117.310(c) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) shall determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.305 or §117.310 of this title, as applicable; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through plant-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources).

§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 NO_x 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 NO_x 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 NO_x 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 ±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 ±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 NO_x 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 NO_x monitor is off-line:

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

(ii) for NO_x monitor downtime periods equal to or greater than 24 consecutive hours, use the maximum block one-hour NO_x 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 NO_x monitor downtime, the owner or operator shall use the maximum block one-hour NO_x 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 ±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 re-

quirements 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 NO_x 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 NO_x 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 NO_x 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 NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation, and fuel-lean and conventional (fuel-rich) reburn.

(C) The NO_x 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 NO_x 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 (NO_x) shall submit, for the approval of the executive director, an initial control plan for installation of NO_x 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 NO_x 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 NO_x, 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 NO_x 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 NO_x 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 (NO_x) 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 NO_x emission specification resulting from application of §117.305 of this title for each non-exempt unit;

(2) the section under which NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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DIVISION 4. DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MAJOR SOURCES

30 TAC §§117.400, 117.403, 117.410, 117.423, 117.425, 117.430, 117.435, 117.440, 117.445, 117.450, 117.454, 117.456

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.400. Applicability.

The provisions of this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources), apply to the following units located at any major stationary source of nitrogen oxides located within the Dallas-Fort Worth eight-hour ozone nonattainment area:

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

(2) stationary gas turbines;

(3) stationary internal combustion engines;

(4) duct burners used in turbine exhaust ducts;

(5) lime kilns;

(6) metallurgical heat treating furnaces and reheat furnaces;

(7) incinerators;

(8) glass, fiberglass, and mineral wool melting furnaces;

(9) fiberglass and mineral wool curing and forming ovens;

(10) natural gas-fired ovens and heaters;

(11) natural gas-fired organic solvent, printing ink, clay, brick, ceramic tile, calcining, and vitrifying dryers;

(12) brick and ceramic kilns;

(13) electric arc melting furnaces used in steel production; and

(14) lead smelting reverberatory and blast (cupola) furnaces.

§117.403. Exemptions.

(a) Units exempted from the provisions of this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources), except as specified in §§117.440(i), 117.445(f)(4) and (9), 117.450, and 117.454 of this title (relating to 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) industrial, commercial, or institutional boilers or process heaters with a maximum rated capacity of 2.0 million British thermal units per hour (MMBtu/hr) or less;

(2) heat treating furnaces and reheat furnaces with a maximum rated capacity less than 20 MMBtu/hr;

(3) flares, incinerators with a maximum rated capacity less than 40 MMBtu/hr, pulping liquor recovery furnaces, sulfur recovery units, sulfuric acid regeneration units, molten sulfur oxidation furnaces, and sulfur plant reaction boilers;

(4) dryers, heaters, or ovens with a maximum capacity of 2.0 MMBtu/hr or less;

(5) any dryers, heaters, or ovens fired on fuels other than natural gas. This exemption does not apply to gas-fired curing and forming ovens used for the production of mineral wool-type or textile-type fiberglass;

(6) any glass, fiberglass, and mineral wool melting furnaces with a maximum rated capacity of 2.0 MMBtu/hr or less;

(7) 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 June 1, 2007, is ineligible for this exemption. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations (CFR) §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account;

(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;

(8) any stationary diesel engine placed into service before June 1, 2007, 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 June 1, 2007. 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;

(9) any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after June 1, 2007, 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;

(10) 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; and

(11) brick or ceramic kilns with a maximum rated capacity less than 5.0 MMBtu/hr.

(b) Increment of progress exemptions.

(1) Stationary, reciprocating internal combustion engines with a maximum rated capacity less than 300 horsepower are exempt from the emission specifications in §117.410(a) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration).

(2) The emission specifications in §117.410(a) of this title no longer apply to any stationary, reciprocating internal combustion engine subject to the emission specifications of §117.410(b) of this title after the compliance date specified in §117.9030(b) of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources).

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

(a) Emission specifications for increment of progress. The owner or operator of any gas-fired stationary, reciprocating internal combustion engine with a maximum rated horsepower (hp) of 300 hp or greater shall comply with the following emission specifications, in accordance with the applicable schedule in §117.9030(a) of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources), except as provided in subsection (e) of this section:

(1) nitrogen oxides (NO_x), as follows:

(A) lean-burn engines, 2.0 grams per horsepower-hour (g/hp-hr); and

(B) rich-burn engines:

(i) placed into service before January 1, 2000, that have not been modified, reconstructed, or relocated on or after January 1, 2000, 2.0 g/hp-hr. For the purposes of this clause, 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; and

(ii) installed, modified, reconstructed, or relocated on or after January 1, 2000, 0.50 g/hp-hr; and

(2) carbon monoxide (CO), 3.0 g/hp-hr.

(b) Emission specifications for eight-hour ozone attainment demonstration. No person shall allow the discharge into the atmosphere NO_x emissions in excess of the following emission specifications, in accordance with the applicable schedule in §117.9030(b) of this title, except as provided in subsection (e) of this section:

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

(3) process heaters:

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

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

(4) stationary, reciprocating internal combustion engines:

(A) gas-fired rich-burn engines:

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

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

(B) gas-fired lean-burn engines:

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

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

(C) dual-fuel engines, 0.50 g/hp-hr;

(D) diesel engines, excluding dual-fuel engines, placed into service before June 1, 2007, that have not been modified, reconstructed, or relocated on or after June 1, 2007, 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 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

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

(i) with a hp rating of less than 50 hp that are installed, modified, reconstructed, or relocated on or after June 1, 2007, 5.0 g/hp-hr;

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

(I) on or after June 1, 2007, but before January 1, 2008, 5.0 g/hp-hr; and

(II) on or after January 1, 2008, 3.3 g/hp-hr;

(iii) with a hp rating of 100 hp or greater, but less than 750 hp, that are installed, modified, reconstructed, or relocated on or after June 1, 2007, 2.8 g/hp-hr; and

(iv) with a hp rating of 750 hp or greater that are installed, modified, reconstructed, or relocated on or after June 1, 2007, 4.5 g/hp-hr;

(5) stationary gas turbines:

(A) rated at 10 megawatts (MW) or greater, 0.032 lb/MMBtu;

(B) rated at 1.0 MW or greater, but less than 10 MW, 0.15 lb/MMBtu; and

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

(6) duct burners used in turbine exhaust ducts, the corresponding gas turbine emission specification of paragraph (5) of this subsection;

(7) kilns:

(A) lime kilns, 3.1 pounds per ton (lb/ton) of calcium oxide; and

(B) brick and ceramic kilns, 0.175 lb/ton of product;

(8) metallurgical furnaces:

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

(B) reheat furnaces, 0.10 lb/MMBtu;

(C) electric arc furnaces used in steel production, 0.30 lb/ton product; and

(D) lead smelting blast (cupola) and reverberatory furnaces used in conjunction, the combined rate of 0.45 lb/ton product;

(9) incinerators, either of the following:

(A) an 80% reduction from the daily NO_x emissions reported to the Industrial Emissions Assessment Section for the calendar year 2000 Emission Inventory. 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;

(10) glass and fiberglass melting furnaces:

(A) container glass melting furnaces, 1.30 lb/ton of glass pulled;

(B) mineral wool-type electric fiberglass melting furnaces, 1.45 lb/ton of product pulled; and

(C) mineral wool-type fiberglass regenerative furnaces, 1.45 lb/ton of product pulled;

(11) gas-fired curing and forming ovens used for the production of mineral wool-type or textile-type fiberglass, 0.036 lb/MMBtu;

(12) natural gas-fired ovens and heaters, 0.036 lb/MMBtu;

(13) natural gas-fired organic solvent, printing ink, clay, brick, and ceramic tile, calcining, and vitrifying dryers, 0.036 lb/MMBtu; and

(14) as an alternative to the emission specifications in paragraphs (1) - (13) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu. The capacity factor as of December 31, 2000, must be used to determine whether the unit is eligible for the emission specification of this paragraph. A 12-month rolling average must be used to determine the annual capacity factor for units placed into service after December 31, 2000.

(c) NO_x averaging time. The emission specifications of subsections (a) and (b) of this section apply:

(1) if the unit is operated with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.440 of this title (relating to Continuous Demonstration of Compliance), either as:

(A) a rolling 30-day average period, in the units of the applicable standard;

(B) a block one-hour average, in the units of the applicable standard, or alternatively;

(C) a block one-hour average, in pounds per hour, for boilers and process heaters, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable specification in lb/MMBtu; and

(2) if the unit is not operated with a NO_x CEMS or PEMS under §117.440 of this title, a block one-hour average, in the units of the applicable standard. Alternatively for boilers and process heaters, the emission specification may be applied in pounds per hour, as specified in paragraph (1)(C) of this subsection.

(d) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to NO_x emission specifications in subsection (a) or (b) of this section, emissions in excess of the following, except as provided in §117.425 of this title (relating to Alternative Case Specific Specifications) or paragraph (3) or (4) of this subsection.

(1) CO emissions must not exceed 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines; or 775 ppmv at 7.0% O_2, dry basis for wood fuel-fired boilers or process heaters):

(A) on a rolling 24-hour averaging period, for units equipped with CEMS or PEMS for CO; and

(B) on a one-hour average, for units not equipped with CEMS or PEMS for CO.

(2) For units that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions must not exceed 10 ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts) and gas-fired lean-burn engines; 7.0% O_2, dry, for incinerators; and 3.0% O_2, dry, for all other units, based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(3) The correction of CO emissions to 3.0% O_2, dry basis, in paragraph (1) of this subsection does not apply to boilers and process heaters operating at less than 10% of maximum load and with stack O_2 in excess of 15% (i.e., hot-standby mode).

(4) The CO specifications in paragraph (1) of this subsection do not apply to:

(A) stationary internal combustion engines subject to subsection (a) of this section; or

(B) incinerators subject to the CO limits of one of the following:

(i) §111.121 of this title (relating to Single-, Dual-, and Multiple-Chamber Incinerators);

(ii) §113.2072 of this title (relating to Emission Limits) for hospital/medical/infectious waste incinerators; or

(iii) 40 CFR Part 264 or 265, Subpart O, for hazardous waste incinerators.

(e) Compliance flexibility.

(1) An owner or operator may use any of the following alternative methods to comply with the NO_x emission specifications of this section:

(A) §117.423 of this title (relating to Source Cap); or

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

(2) Section 117.425 of this title is not an applicable method of compliance with the NO_x emission specifications of this section.

(3) An owner or operator may petition the executive director for an alternative to the CO or ammonia specifications of this section in accordance with §117.425 of this title.

(f) Prohibition of circumvention.

(1) The maximum rated capacity used to determine the applicability of the emission specifications in this section and the initial compliance demonstration, monitoring, testing requirements, and final control plan in §§117.435, 117.440, and 117.454 of this title (relating to Initial Demonstration of Compliance; Continuous Demonstration of Compliance; and Final Control Plan Procedures for Attainment Demonstration Emission Specifications) must be the greater of the following:

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

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

(C) 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) after December 31, 2000.

(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 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 an emission specification in this section that result in increased NO_x emissions from a unit not subject to an emission specification of this section is prohibited. For example, 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 prohibited.

(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 becomes a major source at any time after December 31, 2000, is from that time forward always classified as a major source for purposes of this chapter.

(5) The availability under subsection (b)(14) 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 (b)(14) of this section than would otherwise apply to the unit.

(6) This subsection does not apply to stationary, reciprocating internal combustion engines subject to subsection (a) of this section until the compliance date specified in §117.9030(b) of this title.

(g) Operating restrictions. No person may 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 from April 1 through October 31.

§117.423. Source Cap.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission specifications of §117.410 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration), by achieving equivalent NO_x 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 NO_x emission specifications of §117.410 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 §117.410 of this title.

(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 §117.423(b)(1)

(2) A maximum daily cap must be calculated for all emission units included in the source cap using the following equation.
Figure: 30 TAC §117.423(b)(2)

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

(4) For stationary internal combustion engines, the source cap allowable emission rate must be calculated in pounds per hour using the following equation.
Figure: 30 TAC §117.423(b)(4)

(5) For stationary gas turbines, the source cap allowable emission rate must be calculated in pounds per hour using the following equations.
Figure: 30 TAC §117.423(b)(5)

(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 NO_x 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 §117.440 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 §117.440 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, use the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117.435(d) 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 §117.435(d) of this title; and

(2) for each operating unit equipped with CEMS, either use a PEMS in accordance with §117.440 of this title, or the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117.435(d) of this title, to provide emissions compliance data during periods when the CEMS is off-line. The methods specified in 40 Code of Federal Regulations §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 NO_x emissions from each source and the total fuel usage for each unit and include a total NO_x 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 §117.445 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 §117.445 of this title.

(f) The owner or operator shall demonstrate initial compliance with the source cap in accordance with the schedule specified in §117.9030 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources)

(g) For compliance with §117.410 of this title, a unit that has been permanently retired or decommissioned and rendered inoperable may be included in the source cap under the following conditions.

(1) Permanent shutdowns must have occurred after December 31, 2000.

(2) The source cap emission limit for retired units is 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, 2000, and December 31, 2001, the actual heat input must be the average daily heat input for the continuous time period that the unit was in service, consistent with the heat input used to represent the unit's emissions in the attainment demonstration modeling inventory. 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 permanent 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.

(h) 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 §117.450 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.

(i) 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 NO_x 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.

§117.425. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of the carbon monoxide (CO) or ammonia specifications of §117.410(c) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstrations), the executive director may approve emission specifications different from the CO or ammonia specifications in §117.410(d) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) shall determine that such specifications are the result of the lowest emission specification the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.410 of this title, as applicable; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through plant-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources).

§117.430. Operating Requirements.

(a) The owner or operator shall operate any unit subject to the source cap emission limits of §117.423 of this title (relating to Source Cap) in compliance with those limitations.

(b) All units subject to the emission specifications of §117.410(a) or (b) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) or §117.423 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 specifications.

(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).

§117.435. Initial Demonstration of Compliance.

(a) The owner or operator of any unit subject to the emission specifications of this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources) shall test the unit as follows.

(1) The unit must be tested for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions while firing gaseous fuel or, as applicable, liquid and solid fuel.

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

(3) Initial demonstration of compliance testing must be performed in accordance with the schedule specified in §117.9030 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour 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 (d) or (e) of this section and must be used for determination of initial compliance with the emission specifications of this division. Test results must be reported in the units of the applicable emission specifications and averaging periods.

(c) Any continuous emissions monitoring system (CEMS) or any predictive emissions monitoring system (PEMS) required by §117.440 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, at 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) Compliance with the emission specifications 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).

(e) Initial compliance with the emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.440 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 specifications in pounds per million British thermal units (lb/MMBtu) 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 §117.423 of this title (relating to Source Cap) a rolling 30-day average of total daily pounds of NO_x emissions from the units are monitored (or calculated in accordance with §117.423(c) of this title) for 30 successive source operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission limit. 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.

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

§117.440. 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 ±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. 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 units subject to §117.410 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstrations):

(A) boilers;

(B) process heaters;

(C) duct burners used in turbine exhaust ducts;

(D) stationary, reciprocating internal combustion engines;

(E) stationary gas turbines;

(F) lime kilns

(G) brick and ceramic kilns;

(H) heat treating furnaces;

(I) reheat furnaces;

(J) electric arc furnaces used in steel production;

(K) lead smelting blast (cupola) and reverberatory furnaces;

(L) glass and fiberglass/mineral wool melting furnaces;

(M) 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);

(N) gas-fired glass, fiberglass, and mineral wool curing and forming ovens;

(O) natural gas-fired ovens and heaters; and

(P) natural gas-fired organic solvent, printing ink, clay, brick, ceramic, and calcining and vitrifying dryers.

(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 Code of Federal Regulations (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 million British thermal units per hour (MMBtu/hr); and

(B) process heaters with a rated heat input greater than or equal to 100 MMBtu/hr, except:

(i) as provided in subsection (g) of this section; and

(ii) for process heaters operating with a carbon dioxide (CO_2) CEMS for diluent monitoring under subsection (f) of this section.

(2) 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) units with a rated heat input greater than or equal to 100 MMBtu/hr that are subject to §117.410(b) of this title;

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

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

(D) units that the owner or operator elects to comply with the NO_x emission specifications of §117.410(b) of this title using a pound per MMBtu (lb/MMBtu) limit on a 30-day rolling average;

(E) lime kilns; and

(F) brick kilns and ceramic kilns.

(2) Units subject to the NO_x CEMS requirements of 40 CFR Part 75 are not required to install CEMS or PEMS under this subsection.

(3) 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:

(A) if the NO_x 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 §117.1340(d) of this title (relating to Continuous Demonstration of Compliance);

(C) if the NO_x 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) the maximum block one-hour emission rate as measured during the initial demonstration of compliance required in §117.435(e) of this title (relating to Initial Demonstration of Compliance).

(d) Ammonia monitoring requirements. The owner or operator of any unit subject to §117.410(b) of this title and the ammonia emission specification of §117.410(c)(2) of this title shall monitor ammonia emissions from the unit according to the requirements of §117.8130 of this title (relating to Ammonia Monitoring).

(e) Carbon monoxide (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 requirements of §117.8100(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources).

(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 limitations of this division (relating to Dallas-Fort Worth Eight-Hour 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 the emission specifications of this division shall stack test engine NO_x and CO emissions as specified in §117.8140(a) of this title (relating to Emission Monitoring for Engines)

(i) Run time meters. The owner or operator of any stationary gas turbine or stationary internal combustion engine claimed exempt using the exemption of §117.403(a)(7)(D), (8), or (9) of this title (relating to Exemptions) shall record the operating time with a non-resettable elapsed run time meter.

(j) Data used for compliance. After the initial demonstration of compliance required by §117.435 of this title, the methods required in this section must be used to determine compliance with the emission specifications of §117.410(a) or (b) 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 specifications.

(k) Testing requirements.

(1) The owner or operator of units that are subject to the emission specifications of §117.410(a) of this title shall test the units as specified in §117.435 of this title in accordance with the schedule specified in §117.9030(a) of this title.

(2) The owner or operator of units that are subject to the emission specifications of §117.410(b) of this title shall test the units as specified in §117.435 of this title in accordance with the schedule specified in §117.9030(b) of this title.

(3) The owner or operator of any unit not equipped with CEMS or PEMS that are subject to the emission specifications of §117.410(b) of this title shall retest the unit as specified in §117.435 of this title within 60 days after any modification that could reasonably be expected to increase the NO_x emission rate.

§117.445. 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) for units subject to the emission specifications of §117.410(a) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration):

(A) verbal notification of the date of any testing conducted under §117.435 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

(B) 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 §117.440 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; and

(2) for units subject to the emission specifications of §117.410(b) of this title, written notification of any CEMS or PEMS RATA conducted under §117.440 of this title or any testing conducted under §117.435 of this title at least 15 days in advance of the date of the RATA or testing.

(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 §117.435 of this title and any CEMS or PEMS RATA conducted under §117.440 of this title:

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

(2) not later than the compliance schedule specified in §117.9030 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS or PEMS under §117.440 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 Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources) and the 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 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. For units complying with §117.423 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 when 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 or PEMS 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 or PEMS 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 the emission specifications in §117.410 of this title 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 §117.430(b)(7) of this title (relating to Operating Requirements) and the biennial emission testing required for demonstration of emissions compliance in accordance with §117.440(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 (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources) 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 §117.440(a) of this title, records of annual fuel usage;

(2) for each unit using a CEMS or PEMS in accordance with §117.440 of this title, monitoring records of:

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

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

(i) pounds per million British thermal units (lb/MMBtu) heat input; 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) §117.430(b)(7) of this title; and

(ii) §117.440(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 units claimed exempt from emission specifications using the exemption of §117.403(a)(7)(D), (8), or (9) of this title (relating to Exemptions), records of monthly hours of operation, for exemptions based on hours per year of operation. In addition, for each engine claimed exempt under §117.403(a)(7)(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;

(5) records of ammonia measurements specified in §117.440(d) of this title;

(6) records of carbon monoxide measurements specified in §117.440(e) of this title;

(7) records of the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS or PEMS;

(8) records of the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.435 of this title; and

(9) 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.

§117.450. Initial Control Plan Procedures.

(a) The owner or operator of any unit at a major source of nitrogen oxides (NO_x) in the Dallas-Fort Worth eight-hour ozone nonattainment area that is subject to §117.410(b) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) shall submit an initial control plan. The control plan must include:

(1) a list of all combustion units at the account that are listed in §117.410(b) of this title. The list must include for each unit:

(A) the maximum rated capacity;

(B) anticipated annual capacity factor;

(C) estimated or measured NO_x emission data in the units associated with the category of equipment from §117.410(b) of this title;

(D) the method of determination for the NO_x emission data required by subparagraph (C) of this paragraph;

(E) the facility identification number and emission point number as submitted to the Industrial Emissions Assessment Section of the commission; and

(F) the emission point number as listed on the Maximum Allowable Emissions Rate Table of any applicable commission permit;

(2) identification of all units with a claimed exemption from the emission specifications §117.410(b) of this title and the rule basis for the claimed exemption;

(3) identification of the election to use the source cap emission limit as specified in §117.423 of this title (relating to Source Cap) to achieve compliance with this rule and a list of the units to be included in the source cap;

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

(5) a list of units requiring operating modifications to comply with §117.430(b) of this title (relating to Operating Requirements) and the type of modification to be applied for all such units, including an anticipated construction schedule;

(6) for units required to install totalizing fuel flow meters in accordance with §117.440(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; and

(7) for units required to install continuous emissions monitoring systems or predictive emissions monitoring systems in accordance with §117.440 of this title, 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.

(b) The initial control plan must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Chief Engineer's Office by the applicable date specified for initial control plans in §117.9030(b) of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources).

(c) For units located in Dallas, Denton, Collin, and Tarrant Counties subject to §117.210 of this title (relating to Emission Specifications for Attainment Demonstration), the owner or operator may elect to submit the most recent revision of the final control plan required by §117.254 of this title (relating to Final Control Plan Procedures for Attainment Demonstration Emission Specifications) in lieu of the initial control plan required by subsection (a) of this section.

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

(a) The owner or operator of any unit subject to §117.410 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstrations) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.410 of this title. The report must include:

(1) the section used to demonstrate compliance, either:

(A) §117.410 of this title;

(B) §117.423 of this title (relating to Source Cap); or

(C) §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 §117.435 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 §117.435 of this title that is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any unit with a claimed exemption from the emission specification of §117.410 of this title.

(b) For sources complying with §117.423 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;

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

(A) the average daily heat input, H_i, specified in §117.423(b)(1) of this title;

(B) the maximum daily heat input, H_{mi}, specified in §117.423(b)(1) of this title;

(C) the method of monitoring emissions; and

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

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

(c) The report must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Chief Engineer's Office by the applicable date specified for final control plans in §117.9030 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour 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 source cap rolling 30-day average emission limit, according to the applicable schedule given in §117.9030 of this title.

§117.456. 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 Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources).

(1) For sources complying with §117.410 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration), replacement new units may be included in the control plan.

(2) For sources complying with §117.423 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 is subject to the review and approval of the executive director.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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SUBCHAPTER C. COMBUSTION CONTROL AT MAJOR UTILITY ELECTRIC GENERATION SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 1. BEAUMONT-PORT ARTHUR OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

30 TAC §§117.1000, 117.1003, 117.1005, 117.1010, 117.1015, 117.1020, 117.1025, 117.1035, 117.1040, 117.1045, 117.1052, 117.1054, 117.1056

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.1000. Applicability.

(a) The provisions of this division (relating to Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources) apply to utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners in turbine exhaust ducts used in an electric power generating system, as defined in §117.10 of this title (relating to Definitions), that is located within the Beaumont-Port Arthur ozone nonattainment area and is owned or operated by:

(1) a municipality or a Public Utility Commission of Texas (PUC) regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC; or

(2) an electric cooperative, independent power producer, municipality, river authority, or public utility.

(b) The provisions of this division are applicable for the life of each affected unit within an electric power generating system or until this division or sections of this title that are applicable to an affected unit are rescinded.

§117.1003. Exemptions.

(a) Reasonably available control technology. Units exempted from the provisions of §§117.1005, 117.1015, and 117.1040 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Alternative System-Wide Emission Specifications; and Continuous Demonstration of Compliance), except as specified in §117.1040(h) - (j) of this title, include the following:

(1) any new units placed into service after November 15, 1992;

(2) any utility boiler or auxiliary steam boiler with an annual heat input less than or equal to $2.2(10^{11})$ British thermal units per year; or

(3) stationary gas turbines and engines, that are:

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

(B) demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

(b) Emission specifications for attainment demonstration. Stationary gas turbines and engines that are used solely to power other engines or gas turbines during startups are exempt from the provisions of §§117.1010, 117.1020, and 117.1040 of this title (relating to Emission Specifications for Attainment Demonstration; System Cap; and Continuous Demonstration of Compliance), except as specified in §117.1040(i) of this title.

(c) Emergency fuel oil firing.

(1) The fuel oil firing emission specifications of §§117.1005(c), 117.1010(a), 117.1015(b), and 117.1020 of this title do not apply during an emergency operating condition declared by the Electric Reliability Council of Texas or the Southeastern Electric Reliability Council, or any other emergency operating condition that necessitates oil firing. All findings that emergency operating conditions exist are subject to the approval of the executive director.

(2) The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction verbal notification as soon as possible but no later than 48 hours after declaration of the emergency. Verbal notification must identify the anticipated date and time oil firing will begin, duration of the emergency period, affected oil-fired equipment, and quantity of oil to be fired in each unit, and must be followed by written notification containing this information no later than five days after declaration of the emergency.

(3) The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having

jurisdiction final written notification as soon as possible but no later than two weeks after the termination of emergency fuel oil firing. Final written notification must identify the actual dates and times that oil firing began and ended, duration of the emergency period, affected oil-fired equipment, and quantity of oil fired in each unit.

§117.1005. Emission Specifications for Reasonably Available Control Technology (RACT).

(a) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, emissions of nitrogen oxides (NO_x) in excess of 0.26 pounds per million British thermal units (lb/MMBtu) heat input on a rolling 24-hour average and 0.20 lb/MMBtu heat input on a 30-day rolling average while firing natural gas or a combination of natural gas and waste oil.

(b) No person shall allow the discharge into the atmosphere from any utility boiler, NO_x emissions in excess of 0.38 lb/MMBtu heat input for tangentially-fired units on a rolling 24-hour averaging period or 0.43 lb/MMBtu heat input for wall-fired units on a rolling 24-hour averaging period while firing coal.

(c) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of 0.30 lb/MMBtu heat input on a rolling 24-hour averaging period while firing fuel oil only.

(d) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of the heat input weighted average of the applicable emission specifications specified in subsections (a) and (c) of this section on a rolling 24-hour averaging period while firing a mixture of natural gas and fuel oil, as follows.
Figure: 30 TAC §117.1005(d)

(e) Each auxiliary steam boiler that is an affected facility as defined by New Source Performance Standards (NSPS) 40 Code of Federal Regulations Part 60, Subparts D, Db, or Dc is limited to the applicable NSPS NO_x emission limit, unless the boiler is also subject to a more stringent permit emission limit, in which case the more stringent emission limit applies. Each auxiliary steam boiler subject to an emission specification under this subsection is not subject to the emission specifications of subsection (a), (c), or (d) of this section.

(f) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a megawatt (MW) rating greater than or equal to 30 MW and an annual electric output in megawatt-hours (MW-hr) of greater than or equal to the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of:

(1) 42 parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis, while firing natural gas; and

(2) 65 ppmv at 15% O_2, dry basis, while firing fuel oil.

(g) No person shall allow the discharge into the atmosphere from any stationary gas turbine used for peaking service with an annual electric output in MW-hr of less than the product of 2,500 hours and the MW rating of the unit NO_x emissions in excess of a block one-hour average of:

(1) 0.20 lb/MMBtu heat input while firing natural gas; and

(2) 0.30 lb/MMBtu heat input while firing fuel oil.

(h) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler subject to the NO_x emission specifications specified in subsections (a) - (e) of this section, carbon monoxide (CO) emissions in excess of 400 ppmv at 3.0% O_2, dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units, 0.31 lb/MMBtu heat input for oil-fired units, and 0.33 lb/MMBtu heat input for coal-fired units), based on:

(1) a one-hour average for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

(2) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO.

(i) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to 10 MW, CO emissions in excess of a block one-hour average of 132 ppmv at 15% O_2, dry basis.

(j) No person shall allow the discharge into the atmosphere from any unit subject to this section, ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(k) For purposes of this subchapter, the following apply.

(1) The lower of any permit NO_x 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 NO_x emission specifications of subsections (a) - (g) of this section apply, except that gas-fired boilers operating under a permit issued after March 3, 1982, with a NO_x emission limit of 0.12 lb/MMBtu heat input, are limited to that rate for the purposes of this subchapter.

(2) For any unit placed into service after June 9, 1993, and prior to the final compliance date as specified in §117.9100 of this title (relating to Compliance Schedule for Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation 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 NO_x emission limit under a permit issued after June 9, 1993, in accordance with Chapter 116 of this title and the emission specifications of subsections (a) - (g) of this section apply. 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 specifications of §117.1015 of this title (relating to Alternative System-Wide Emission Specifications). Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

(l) This section no longer applies to any utility boiler after the appropriate compliance date(s) for emission specifications for attainment demonstration given in §117.9100(2) of this title.

§117.1010. Emission Specifications for Attainment Demonstration.

(a) Nitrogen oxides (NO_x) emission specifications. The owner or operator of each utility boiler shall ensure that emissions of NO_x do not exceed 0.10 pounds per million British thermal units (lb/MMBtu) heat input, on a daily average, except as provided in §117.1020 or §117.9800 of this title (relating to System Cap; and Use of Emission Credits for Compliance).

(b) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to the NO_x emission specifications specified in subsection (a) of this section:

(1) carbon monoxide (CO) emissions in excess of 400 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units, 0.31 lb/MMBtu heat input for oil-fired units, and 0.33 lb/MMBtu heat input for coal-fired units), based on:

(A) a one-hour average for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO; and

(2) for units that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions in excess of 10 ppmv, at 3.0% O_2, dry, for boilers and 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(c) Compliance flexibility.

(1) An owner or operator may use either of the following alternative methods of compliance with the NO_x emission specifications of this section:

(A) §117.1020 of this title; or

(B) §117.9800 of this title.

(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 §117.1025 of this title (relating to Alternative Case Specific Specifications).

(3) Section 117.1015 of this title (relating to Alternative System-Wide Emission Specifications) and §117.1025 of this title are not alternative methods of compliance with the NO_x emission specifications of this section.

§117.1015. Alternative System-Wide Emission Specifications.

(a) An owner or operator of any gaseous- or coal-fired utility boiler or stationary gas turbine may achieve compliance with the nitrogen oxides (NO_x) emission specifications of §117.1005 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) by achieving compliance with a system-wide emission specification. Any owner or operator who elects to comply with system-wide emission specifications shall reduce emissions of NO_x from affected units so that, if all such units were operated at their maximum rated capacity, the system-wide emission rate from all units in the system as defined in §117.10 of this title (relating to Definitions) would not exceed the system-wide emission specification as defined in §117.10 of this title.

(1) The following units must comply with the individual emission specifications of §117.1005 of this title and must not be included in the system-wide emission specification:

(A) gas turbines used for peaking service subject to the emission specifications of §117.1005(g) of this title; and

(B) auxiliary steam boilers subject to the emission specifications of §117.1005(a), (c), (d), or (e) of this title.

(2) Coal-fired utility boilers must have a separate system average under this section, limited to those units.

(3) Oil-fired utility boilers must have a separate system average under this section, limited to those units. The NO_x emission specification assigned to each oil-fired unit in the system must not exceed 0.5 pounds per million British thermal units (lb/MMBtu) based on a rolling 24-hour average.

(b) The owner or operator shall establish enforceable emission limits for each affected unit in the system calculated in accordance with the maximum rated capacity averaging in this section as follows:

(1) for each gas-fired unit in the system, in lb/MMBtu:

(A) on a rolling 24-hour averaging period; and

(B) on a rolling 30-day averaging period;

(2) for each coal-fired unit in the system, in lb/MMBtu on a rolling 24-hour averaging period;

(3) for stationary gas turbines, in the units of the appropriate emission specification of §117.1005 of this title; and

(4) for each fuel oil-fired unit in the system, in lb/MMBtu on a rolling 24-hour averaging period.

(c) An owner or operator of any gaseous and liquid fuel-fired utility boiler or gas turbine shall:

(1) comply with the assigned maximum allowable emission rates for gas fuel while firing natural gas only;

(2) comply with the assigned maximum allowable emission rate for liquid fuel while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing, 24-hour average, allowable emission specification and the assigned liquid-firing allowable emission specification while operating on liquid and gaseous fuel concurrently.

(d) Solely for purposes of calculating the system-wide emission specification, the allowable mass emission rate for each affected unit must be calculated from the emission specifications of §117.1005 of this title, as follows.

(1) The NO_x emissions rate (in pounds per hour) for each affected utility boiler is determined by the following equation.
Figure: 30 TAC §117.1015(d)(1)

(2) The NO_x emissions rate (in pounds per hour) for each affected stationary gas turbine is determined by the following equations.
Figure: 30 TAC §117.1015(d)(2)

§117.1020. System Cap.

(a) An owner or operator of an electric generating facility (EGF) may achieve compliance with the nitrogen oxides (NO_x) emission specifications of §117.1010 of this title (relating to Emission Specifications for Attainment Demonstration) by achieving equivalent NO_x emission reductions obtained by compliance with a daily and 30-day system cap emission limitation in accordance with the requirements of this section.

(b) Each EGF within an electric power generating system, as defined in §117.10 of this title (relating to Definitions), that would otherwise be subject to the NO_x emission rates of §117.1010 of this title must be included in the system cap.

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

(1) A rolling 30-day average emission cap must be calculated using the following equation.
Figure: 30 TAC §117.1020(c)(1)

(2) A maximum daily cap must be calculated using the following equation.
Figure: 30 TAC §117.1020(c)(2)

(3) Each EGF in the system cap is subject to the emission limits of both paragraphs (1) and (2) of this subsection at all times.

(d) The NO_x emissions monitoring required by §117.1040 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) Part 75, use the missing data procedures specified in 40 CFR Part 75, Subpart D (Missing Data Substitution Procedures); or

(B) 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);

(2) use Appendix E monitoring in accordance with §117.1040(d) of this title;

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

(A) use the methods specified in 40 CFR Part 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 NO_x emissions and fuel usage from each EGF and summations of total NO_x emissions and fuel usage for all EGFs under the system cap on a daily basis. Records must also be retained in accordance with §117.1045 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 §117.1045 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 §117.9100 of this title (relating to Compliance Schedule for Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation 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, 1999. 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 NO_x emission rate measured by the NO_x monitor, if operating properly. If the NO_x monitor is not operating properly, the substitute data procedures identified in subsection (e) of this section must be used. If neither the NO_x 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.

(l) An owner or operator of a source of NO_x who is participating in the system cap under this section may exceed their system cap provided that the owner or operator is complying with the requirements of §117.9800 of this title (relating to Use of Emission Credits for Compliance) or Chapter 101, Subchapter H, Division 1, 4, or 5 of this title (relating to Emission Credit Banking and Trading; Discrete Emission Credit Banking and Trading; and System Cap Trading).

(m) In the event that a unit within an electric power generating system is sold or transferred, the unit must become subject to the transferee's system cap.

§117.1025. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.1005 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), or the carbon monoxide (CO) or ammonia specifications of §117.1010(b) of this title (relating to Emission Specifications for Attainment Demonstration), the executive director may approve emission specifications different from §117.1005 of this title or the CO or ammonia specifications in §117.1010(b) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) shall determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.1005 or §117.1010 of this title, as applicable; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through system-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources).

§117.1035. Initial Demonstration of Compliance.

(a) The owner or operator of all units that are subject to the emission specifications of this division (relating to Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources) shall test the units as follows.

(1) The units must be tested for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions.

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

(3) Testing must be performed in accordance with the schedules specified in §117.9100 of this title (relating to Compliance Schedule for Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources).

(b) The tests required by subsection (a) of this section must be used for determination of initial compliance with the emission specifications of this division. Test results must be reported in the units of the applicable emission specifications and averaging periods. If compliance testing is based on 40 Code of Federal Regulations Part 60, Appendix A reference methods, the report must contain the information specified in §117.8010 of this title (relating to Compliance Stack Test Reports).

(c) Continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) required by §117.1040 of this title (relating to Continuous Demonstration of Compliance) must be installed and operational before testing under subsection (a) of this section. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(d) Initial compliance with the emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.1040 of this title must be demonstrated after monitor certification testing using the NO_x CEMS or PEMS as follows.

(1) To comply with the NO_x emission specification in pounds per million British thermal units (lb/MMbtu) on a rolling 30-day average, NO_x emissions from a 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) To comply with the NO_x emission specification in lb/MMBtu on a rolling 24-hour average, NO_x emissions from a unit are monitored for 24 consecutive operating hours and the 24-hour average emission rate is used to determine compliance with the NO_x emission specification. The 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period. Compliance with the NO_x emission specification for fuel oil firing must be determined based on the first 24 consecutive operating hours a unit fires fuel oil.

(3) For any electric generating facility (EGF) complying with §117.1020 of this title (relating to System Cap), a rolling 30-day average of total daily pounds of NO_x emissions from the EGF must be monitored (or calculated in accordance with §117.1020(e) of this title) for 30 successive system 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 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.

(4) To comply with the NO_x emission specification in pounds per hour or parts per million by volume (ppmv) at 15% O_2 dry basis, on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable, after CEMS or PEMS certification testing required in §117.1040 of this title is used to determine compliance with the NO_x emission specification.

(5) To comply with the CO emission specification in ppmv on a rolling 24-hour average, CO emissions from a unit are monitored for 24 consecutive hours and the rolling 24-hour average emission rate is used to determine compliance with the CO emission specification. The rolling 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period.

§117.1040. Continuous Demonstration of Compliance.

(a) Nitrogen oxides (NO_x) monitoring. The owner or operator of each unit subject to the emission specifications of this division (relating to Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources), shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS), predictive emissions monitoring system (PEMS), or other system specified in this section to measure NO_x on an individual basis. Each NO_x monitor (CEMS or PEMS) is subject to the relative accuracy test audit relative accuracy requirements of 40 Code of Federal Regulations (CFR) Part 75, Appendix B, Figure 2, except the concentration options (parts per million by volume (ppmv) and pounds per million British thermal units) do not apply. Each NO_x monitor must meet either the relative accuracy percent requirement of 40 CFR Part 75, Appendix B, Figure 2, or an alternative relative accuracy requirement of ±2.0 ppmv from the reference method mean value.

(b) Carbon monoxide (CO) monitoring. The owner or operator shall monitor CO exhaust emissions from each unit subject to the emission specifications of this division using one or more of the methods specified in §117.8120 of this title (relating to Carbon Monoxide (CO) Monitoring).

(c) CEMS requirements. The owner or operator of any CEMS used to meet a pollutant monitoring requirement of this section shall comply with the requirements of §117.8110(a) of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources).

(d) Acid rain peaking units. The owner or operator of each peaking unit as defined in 40 CFR §72.2, may:

(1) monitor operating parameters for each unit in accordance with 40 CFR Part 75, Appendix E, §1.1 or §1.2 and calculate NO_x emission rates based on those procedures; or

(2) use CEMS or PEMS in accordance with this section to monitor NO_x emission rates.

(e) Auxiliary steam boilers. The owner or operator of each auxiliary steam boiler as defined in §117.10 of this title (relating to Definitions) shall:

(1) install, calibrate, maintain, and operate a CEMS in accordance with this section; or

(2) comply with the appropriate (considering boiler maximum rated capacity and annual heat input) industrial boiler monitoring requirements of §117.140 of this title (relating to Continuous Demonstration of Compliance).

(f) PEMS requirements. The owner or operator of any PEMS used to meet a pollutant monitoring requirement of this section shall comply with the following. The required PEMS and fuel flow meters must be used to demonstrate continuous compliance with the emission specifications of this division.

(1) The PEMS must predict the pollutant emissions in the units of the applicable emission specifications of this division.

(2) The PEMS must meet the requirements of §117.8110(b) of this title.

(g) Stationary gas turbine monitoring for NO_x reasonably available control technology (RACT). The owner or operator of each stationary gas turbine subject to the emission specifications of §117.1005 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), instead of monitoring emissions in accordance with the monitoring requirements of 40 CFR Part 75, may comply with the following monitoring requirements:

(1) for stationary gas turbines rated less than 30 megawatts (MW) or peaking gas turbines (as defined in §117.10 of this title) that use steam or water injection to comply with the emission specifications of §117.1005(g) of this title:

(A) install, calibrate, maintain, and operate a CEMS or PEMS in compliance with this section; or

(B) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. The system must be accurate to within ±5.0%. The steam-to-fuel or water-to-fuel ratio monitoring data must be used for demonstrating continuous compliance with the applicable emission specification of §117.1005 of this title; and

(2) for stationary gas turbines subject to the emission specifications of §117.1005(f) of this title, install, calibrate, maintain, and operate a CEMS or PEMS in compliance with this section.

(h) Totalizing fuel flow meters. The owner or operator of units listed in this subsection shall install, calibrate, maintain, and operate totalizing fuel flow meters 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. In lieu of installing a totalizing fuel flow meter on a unit, an owner or operator may opt to assume fuel consumption at maximum design fuel flow rates during hours of the unit's operation. The units are:

(1) any unit subject to the emission specifications of this division;

(2) any stationary gas turbine with an MW rating greater than or equal to 1.0 MW operated more than 850 hours per year; and

(3) any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.1003(a)(2) of this title (relating to Exemptions).

(i) Run time meters. The owner or operator of any stationary gas turbine using the exemption of §117.1003(a)(3) or (b) of this title shall record the operating time with an elapsed run time meter approved by the executive director.

(j) Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemptions of §117.1003(a)(2) or (3) of this title, shall notify the executive director within seven days if the applicable limit 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.

(k) Data used for compliance. After the initial demonstration of compliance required by §117.1035 of this title (relating to Initial Demonstration of Compliance), the methods required in this section must be used to determine compliance with the emission specifications of §117.1005 of this title or §117.1010(a) of this title (relating to Emission Specifications for Attainment Demonstration). Compliance with the emission specifications may also be determined at the discretion of the executive director using any commission compliance method.

(l) Enforcement of NO_x RACT limits. If compliance with §117.1005 of this title is selected, no unit subject to §117.1005 of this title may be operated at an emission rate higher than that allowed by the emission specifications of §117.1005 of this title. If compliance with §117.1015 of this title (relating to Alternative System-Wide Emission Specifications) is selected, no unit subject to §117.1015 of this title may be operated at an emission rate higher than that approved by the executive director in accordance with §117.1052(b) of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology).

§117.1045. 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, 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 fuel burned; gross and net energy production in megawatt-hours (MW-hr); and the date, time, and duration of the event.

(b) Notification. The owner or operator of a unit subject to the emission specifications of this division (relating to Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources) 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 §117.1035 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) performance evaluation conducted under §117.1040 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 §117.1035 of this title or any CEMS or PEMS performance evaluation conducted under §117.1040 of this title:

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

(2) not later than the appropriate compliance schedules specified in §117.9100 of this title (relating to Compliance Schedule for Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system under §117.1040 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission specifications in this division and the 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 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 §117.1040 of this title, excess emissions are computed as each one-hour period that the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial demonstration of compliance test required by §117.1035 of this title; and

(B) for utility boilers complying with §117.1020 of this title (relating to System 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 steam-to-fuel or water-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 or steam-to-fuel or water-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) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain records of the data specified in this subsection. Records must be kept for a period of at least five years and made available for inspection by the executive director, United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction upon request. Operating records for each unit must be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or for units claimed exempt from the emission specifications based on low annual capacity factor, monthly. Records must include:

(1) emission rates in units of the applicable standards;

(2) gross energy production in MW-hr (not applicable to auxiliary steam boilers);

(3) quantity and type of fuel burned;

(4) the injection rate of reactant chemicals (if applicable); and

(5) emission monitoring data, in accordance with §117.1040 of this title, including:

(A) the date, time, and duration of any malfunction in the operation of the monitoring system, except for zero and span checks, if applicable, and a description of system repairs and adjustments undertaken during each period;

(B) the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, PEMS, or operating parameter monitoring systems; and

(C) actual emissions or operating parameter measurements, as applicable;

(6) the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.1035 of this title; and

(7) records of hours of operation.

§117.1052. Final Control Plan Procedures for Reasonably Available Control Technology.

(a) The owner or operator of units listed in §117.1000 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.1005 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)). The report must include a list of all units listed in §117.1000 of this title, showing:

(1) the NO_x emission specification resulting from application of §117.1005 of this title for each non-exempt unit;

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

(A) §117.1005 of this title;

(B) §117.1015 of this title (relating to Alternative System-Wide Emission Specifications);

(C) §117.1025 of this title (relating to Alternative Case Specific Specifications); or

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

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

(4) the emissions measured by testing required in §117.1035 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 §117.1035 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 Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources).

(b) For sources complying with §117.1015 of this title, in addition to the requirements of subsection (a) of this section, the owner or operator shall:

(1) assign to each affected unit the maximum NO_x emission rate, expressed in units of pounds per million British thermal units heat input on:

(A) a rolling 24-hour average and rolling 30-day average for gaseous fuel firing; and

(B) a rolling 24-hour average for oil or coal firing;

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

(A) the maximum allowable NO_x 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 system-wide average in accordance with §117.1015(e) of this title; and

(4) maintain a copy of the approved list of emission specifications for verification of continued compliance with the requirements of §117.1015 of this title.

(c) The report must be submitted by the applicable date specified for final control plans in §117.9100 of this title (relating to Compliance Schedule for Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation 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 specification on a rolling 30-day average, according to the applicable schedule given in §117.9100 of this title.

§117.1054. Final Control Plan Procedures for Attainment Demonstration Emission Specifications.

(a) The owner or operator of utility boilers listed in §117.1000 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit to the executive director a final control report to show compliance with the requirements of §117.1010 of this title (relating to Emission Specifications for Attainment Demonstration). The report must include:

(1) the section under which NO_x compliance is being established for the utility boilers within the electric generating system, either:

(A) §117.1010 of this title; or

(B) §117.1020 of this title (relating to System Cap); and as applicable,

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

(2) the methods of NO_x control for each utility boiler;

(3) the emissions measured by testing required in §117.1035 of this title (relating to Initial Demonstration of Compliance);

(4) 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 §117.1035 of this title that is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any utility boiler with a claimed exemption from the emission specifications of §117.1010 of this title.

(b) For sources complying with §117.1020 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 system cap allowable emission rates;

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

(A) the average daily heat input, H_i, specified in §117.1020(c)(1) of this title;

(B) the maximum daily heat input, H_{mi}, specified in §117.1020(c)(2) of this title;

(C) the method of monitoring emissions; and

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

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

(c) The report must be submitted by the applicable date specified for final control plans in §117.9100 of this title (relating to Compliance Schedule for Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation 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 §117.9100 of this title.

§117.1056. 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 emission specification and the final compliance dates of this division (relating to Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources). For sources complying with §§117.1005, 117.1010, or 117.1015 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Emission Specifications for Attainment Demonstration; and Alternative System-Wide Emission Specifications), replacement new units may be included in the control plan. The revision of the final control plan is subject to the review and approval of the executive director.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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DIVISION 2. DALLAS-FORT WORTH OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

30 TAC §§117.1100, 117.1103, 117.1105, 117.1110, 117.1115, 117.1120, 117.1125, 117.1135, 117.1140, 117.1145, 117.1152, 117.1154, 117.1156

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.1100. Applicability.

(a) The provisions of this division (relating to Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources apply to utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners in turbine exhaust ducts used in an electric power generating system, as defined in §117.10 of this title (relating to Definitions), that is located within the Dallas-Fort Worth ozone nonattainment area and is owned or operated by:

(1) a municipality or a Public Utility Commission of Texas (PUC) regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC; or

(2) an electric cooperative, independent power producer, municipality, river authority, or public utility.

(b) The provisions of this division are applicable for the life of each affected unit within an electric power generating system or until this division or sections of this title that are applicable to an affected unit are rescinded.

(c) This division no longer applies to any electric generating facility in Collin, Dallas, Denton, and Tarrant Counties that is subject to the emission specifications in §117.1310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) after the appropriate compliance date(s) specified in §117.9130 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources).

§117.1103. Exemptions.

(a) Reasonably available control technology. Units exempted from the provisions of §§117.1105, 117.1115, and 117.1140 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Alternative System-Wide Emission Specifications; and Continuous Demonstration of Compliance), except as specified in §117.1140(h) - (j) of this title, include the following:

(1) any new units placed into service after November 15, 1992;

(2) any utility boiler or auxiliary steam boiler with an annual heat input less than or equal to $2.2(10^{11})$ British thermal units per year; or

(3) stationary gas turbines and engines, that are:

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

(B) demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

(b) Emission specifications for attainment demonstration. Stationary gas turbines and engines that are used solely to power other engines or gas turbines during startups are exempt from the provisions of §§117.1110, 117.1120, and 117.1140 of this title (relating to Emission Specifications for Attainment Demonstration; System Cap; and Continuous Demonstration of Compliance), except as specified in §117.1140(i) of this title.

(c) Emergency fuel oil firing.

(1) The fuel oil firing emission specifications of §§117.1105(c), 117.1110(a), 117.1115(b), and 117.1120 of this title do not apply during an emergency operating condition declared by the Electric Reliability Council of Texas, or any other emergency operating condition that necessitates oil firing. All findings that emergency operating conditions exist are subject to the approval of the executive director.

(2) The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction verbal notification as soon as possible but no later than 48 hours after declaration of the emergency. Verbal notification must identify the anticipated date and time oil firing will begin, duration of the emergency period, affected oil-fired equipment, and quantity of oil to be fired in each unit, and must be followed by written notification containing this information no later than five days after declaration of the emergency.

(3) The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction final written notification as soon as possible but no later than two weeks after the termination of emergency fuel oil firing. Final written notification must identify the actual dates and times that oil firing began and ended, duration of the emergency period, affected oil-fired equipment, and quantity of oil fired in each unit.

§117.1105. Emission Specifications for Reasonably Available Control Technology (RACT).

(a) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, emissions of nitrogen oxides (NO_x) in excess of 0.26 pound per million British thermal units (lb/MMBtu) heat input on a rolling 24-hour average and 0.20 lb/MMBtu heat input on a 30-day rolling average while firing natural gas or a combination of natural gas and waste oil.

(b) No person shall allow the discharge into the atmosphere from any utility boiler, NO_x emissions in excess of 0.38 lb/MMBtu heat input for tangentially-fired units on a rolling 24-hour averaging period or 0.43 lb/MMBtu heat input for wall-fired units on a rolling 24-hour averaging period while firing coal.

(c) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of 0.30 lb/MMBtu heat input on a rolling 24-hour averaging period while firing fuel oil only.

(d) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of the heat input weighted average of the applicable emission specifications specified in subsections (a) and (c) of this section on a rolling 24-hour averaging period while firing a mixture of natural gas and fuel oil, as follows.
Figure: 30 TAC §117.1105(d)

(e) Each auxiliary steam boiler that is an affected facility as defined by New Source Performance Standards (NSPS) 40 Code of Federal Regulations Part 60, Subparts D, Db, or Dc is limited to the applicable NSPS NO_x emission limit, unless the boiler is also subject to a more stringent permit emission limit, in which case the more stringent emission limit applies. Each auxiliary steam boiler subject to an emission specification under this subsection is not subject to the emission specifications of subsection (a), (c), or (d) of this section.

(f) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a megawatt (MW) rating greater than or equal to 30 MW and an annual electric output in megawatt-hours (MW-hr) of greater than or equal to the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of:

(1) 42 parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis, while firing natural gas; and

(2) 65 ppmv at 15% O_2, dry basis, while firing fuel oil.

(g) No person shall allow the discharge into the atmosphere from any stationary gas turbine used for peaking service with an annual electric output in MW-hr of less than the product of 2,500 hours and the MW rating of the unit NO_x emissions in excess of a block one-hour average of:

(1) 0.20 lb/MMBtu heat input while firing natural gas; and

(2) 0.30 lb/MMBtu heat input while firing fuel oil.

(h) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler subject to the NO_x emission specifications specified in subsections (a) - (e) of this section, carbon monoxide (CO) emissions in excess of 400 ppmv at 3.0% O_2, dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units, 0.31 lb/MMBtu heat input for oil-fired units, and 0.33 lb/MMBtu heat input for coal-fired units), based on:

(1) a one-hour average for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

(2) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO.

(i) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to 10 MW, CO emissions in excess of a block one-hour average of 132 ppmv at 15% O_2, dry basis.

(j) No person shall allow the discharge into the atmosphere from any unit subject to this section, ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(k) For purposes of this subchapter, the following apply.

(1) The lower of any permit NO_x 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 NO_x emission specifications of subsections (a) - (g) of this section apply, except that gas-fired boilers operating under a permit issued after March 3, 1982, with a NO_x emission limit of 0.12 lb/MMBtu heat input, are limited to that rate for the purposes of this subchapter.

(2) For any unit placed into service after June 9, 1993, and prior to the final compliance date as specified in §117.9110 of this title (relating to Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation 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 NO_x emission limit under a permit issued after June 9, 1993, in accordance with Chapter 116 of this title and the emission specifications of subsections (a) - (g) of this section apply. 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 specifications of §117.1115 of this title (relating to Alternative System-Wide Emission Specifications). Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

(l) This section no longer applies to any utility boiler after the appropriate compliance date(s) for emission specifications for attainment demonstration given in §117.9110(2) of this title.

§117.1110. Emission Specifications for Attainment Demonstration.

(a) Nitrogen oxides (NO_x) emission specifications. The owner or operator of each utility boiler shall ensure that emissions of NO_x do not exceed:

(1) 0.033 pounds per million British thermal units (lb/MMBtu) heat input from boilers that are part of a large utility system, as defined in §117.10 of this title (relating to Definitions), on a daily average, except as provided in §117.1120 or §117.9800 of this title (relating to System Cap; and Use of Emission Credits for Compliance); and

(2) 0.06 lb/MMBtu heat input from boilers that are part of a small utility system, as defined in §117.10 of this title, on a daily average, except as provided in §117.1120 or §117.9800 of this title. The annual heat input exemption of §117.1103(a)(2) of this title (relating to Exemptions) is not applicable to a small utility system.

(b) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to the NO_x emission specifications specified in subsection (a) of this section:

(1) carbon monoxide (CO) emissions in excess of 400 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units, 0.31 lb/MMBtu heat input for oil-fired units, and 0.33 lb/MMBtu heat input for coal-fired units), based on:

(A) a one-hour average for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO; and

(2) for units that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions in excess of 10 ppmv, at 3.0% O_2, dry, for boilers and 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(c) Compliance flexibility.

(1) An owner or operator may use either of the following alternative methods of compliance with the NO_x emission specifications of this section:

(A) §117.1120 of this title; or

(B) §117.9800 of this title.

(2) An owner or operator may petition the executive director for an alternative to the CO or ammonia specification of this section in accordance with §117.1125 of this title (relating to Alternative Case Specific Specifications).

(3) Section 117.1115 of this title (relating to Alternative System-Wide Emission Specifications) and §117.1125 of this title are not alternative methods of compliance with the NO_x emission specifications of this section.

§117.1115. Alternative System-Wide Emission Specifications.

(a) An owner or operator of any gaseous- or coal-fired utility boiler or stationary gas turbine may achieve compliance with the nitrogen oxides (NO_x) emission specifications of §117.1105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) by achieving compliance with a system-wide emission specification. Any owner or operator who elects to comply with system-wide emission specifications shall reduce emissions of NO_x from affected units so that, if all such units were operated at their maximum rated capacity, the system-wide emission rate from all units in the system as defined in §117.10 of this title (relating to Definitions) would not exceed the system-wide emission specification as defined in §117.10 of this title.

(1) The following units must comply with the individual emission specifications of §117.1105 of this title and must not be included in the system-wide emission specification:

(A) gas turbines used for peaking service subject to the emission specifications of §117.1105(g) of this title; and

(B) auxiliary steam boilers subject to the emission specifications of §117.1105(a), (c), (d), or (e) of this title.

(2) Coal-fired utility boilers must have a separate system average under this section, limited to those units.

(3) Oil-fired utility boilers must have a separate system average under this section, limited to those units. The NO_x emission specification assigned to each oil-fired unit in the system must not exceed 0.5 pounds per million British thermal units (lb/MMBtu) based on a rolling 24-hour average.

(b) The owner or operator shall establish enforceable emission limits for each affected unit in the system calculated in accordance with the maximum rated capacity averaging in this section as follows:

(1) for each gas-fired unit in the system, in lb/MMBtu:

(A) on a rolling 24-hour averaging period; and

(B) on a rolling 30-day averaging period;

(2) for each coal-fired unit in the system, in lb/MMBtu on a rolling 24-hour averaging period;

(3) for stationary gas turbines, in the units of the appropriate emission specification of §117.1105 of this title; and

(4) for each fuel oil-fired unit in the system, in lb/MMBtu on a rolling 24-hour averaging period.

(c) An owner or operator of any gaseous and liquid fuel-fired utility boiler or gas turbine shall:

(1) comply with the assigned maximum allowable emission rates for gas fuel while firing natural gas only;

(2) comply with the assigned maximum allowable emission rate for liquid fuel while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing, 24-hour average, allowable emission specification and the assigned liquid-firing allowable emission specifications while operating on liquid and gaseous fuel concurrently.

(d) Solely for purposes of calculating the system-wide emission specification, the allowable mass emission rate for each affected unit must be calculated from the emission specifications of §117.1105 of this title, as follows.

(1) The NO_x emissions rate (in pounds per hour) for each affected utility boiler is determined by the following equation.
Figure: 30 TAC §117.1115(d)(1)

(2) The NO_x emissions rate (in pounds per hour) for each affected stationary gas turbine is determined by the following equations.
Figure: TAC 30 §117.1115(d)(2)

§117.1120. System Cap.

(a) An owner or operator of an electric generating facility (EGF) may achieve compliance with the nitrogen oxides (NO_x) emission specifications of §117.1110 of this title (relating to Emission Specifications for Attainment Demonstration) by achieving equivalent NO_x emission reductions obtained by compliance with a daily and 30-day system cap emission limitation in accordance with the requirements of this section.

(b) Each EGF within an electric power generating system, as defined in §117.10 of this title (relating to Definitions), that would otherwise be subject to the NO_x emission rates of §117.1110 of this title must be included in the system cap.

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

(1) A rolling 30-day average emission cap must be calculated using the following equation.
Figure: 30 TAC §117.1120(c)(1)

(2) A maximum daily cap must be calculated using the following equation.
Figure: 30 TAC §117.1120(c)(2)

(3) Each EGF in the system cap is subject to the emission limits of both paragraphs (1) and (2) of this subsection at all times.

(d) The NO_x emissions monitoring required by §117.1140 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) Part 75, use the missing data procedures specified in 40 CFR Part 75, Subpart D (Missing Data Substitution Procedures); or

(B) 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);

(2) use Appendix E monitoring in accordance with §117.1140(d) of this title;

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

(A) use the methods specified in 40 CFR Part 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) if the methods specified in paragraphs (1) - (3) of this subsection are not used, the owner or operator shall 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 NO_x emissions and fuel usage from each EGF and summations of total NO_x emissions and fuel usage for all EGFs under the system cap on a daily basis. Records must also be retained in accordance with §117.1145 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 §117.1145 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 §117.9110 of this title (relating to Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation 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, 1999. 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 NO_x emission rate measured by the NO_x monitor, if operating properly. If the NO_x monitor is not operating properly, the substitute data procedures identified in subsection (e) of this section must be used. If neither the NO_x 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.

(l) An owner or operator of a source of NO_x who is participating in the system cap under this section may exceed their system cap provided that the owner or operator is complying with the requirements of §117.9800 of this title (relating to Use of Emission Credits for Compliance) or Chapter 101, Subchapter H, Division 1, 4, or 5 of this title (relating to Emission Credit Banking and Trading; Discrete Emission Credit Banking and Trading; and System Cap Trading).

(m) In the event that a unit within an electric power generating system is sold or transferred, the unit must become subject to the transferee's system cap. The value R_i in this section is based on the unit's status as part of a large or small system as of January 1, 2000, and does not change as a result of sale or transfer of the unit, regardless of the size of the transferee's system.

§117.1125. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.1105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), or the carbon monoxide (CO) or ammonia specifications of §117.1110(b) of this title (relating to Emission Specifications for Attainment Demonstration), the executive director may approve emission specifications different from §117.1105 of this title or the CO or ammonia specifications in §117.1110(b) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) shall determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.1105 or §117.1110 of this title, as applicable; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through system-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources.

§117.1135. Initial Demonstration of Compliance.

(a) The owner or operator of all units that are subject to the emission specifications of this division (relating to Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources) shall test the units as follows.

(1) The units must be tested for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions.

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

(3) Testing must be performed in accordance with the schedules specified in §117.9110 of this title (relating to Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources).

(b) The tests required by subsection (a) of this section must be used for determination of initial compliance with the emission specifications of this division. Test results must be reported in the units of the applicable emission specifications and averaging periods. If compliance testing is based on 40 Code of Federal Regulations Part 60, Appendix A reference methods, the report must contain the information specified in §117.8010 of this title (relating to Compliance Stack Test Reports).

(c) Continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) required by §117.1140 of this title (relating to Continuous Demonstration of Compliance) must be installed and operational before testing under subsection (a) of this section. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(d) Initial compliance with the emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.1140 of this title must be demonstrated after monitor certification testing using the NO_x CEMS or PEMS as follows.

(1) To comply with the NO_x emission specification in pounds per million British thermal units (lb/MMBtu) on a rolling 30-day average, NO_x emissions from a 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) To comply with the NO_x emission specification in lb/MMBtu on a rolling 24-hour average, NO_x emissions from a unit are monitored for 24 consecutive operating hours and the 24-hour average emission rate is used to determine compliance with the NO_x emission specification. The 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period. Compliance with the NO_x emission specification for fuel oil firing must be determined based on the first 24 consecutive operating hours a unit fires fuel oil.

(3) Any electric generating facility (EGF) complying with §117.1120 of this title (relating to System Cap), a rolling 30-day average of total daily pounds of NO_x emissions from the EGF must be monitored (or calculated in accordance with §117.1120(e) of this title) for 30 successive system 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 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.

(4) To comply with the NO_x emission specification in pounds per hour or parts per million by volume (ppmv) at 15% O_2 dry basis, on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable, after CEMS or PEMS certification testing required in §117.1140 of this title is used to determine compliance with the NO_x emission specification.

(5) To comply with the CO emission specification in ppmv on a rolling 24-hour average, CO emissions from a unit are monitored for 24 consecutive hours and the rolling 24-hour average emission rate is used to determine compliance with the CO emission specification. The rolling 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period.

§117.1140. Continuous Demonstration of Compliance.

(a) Nitrogen oxides (NO_x) monitoring. The owner or operator of each unit subject to the emission specifications of this division (relating to Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources), shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS), predictive emissions monitoring system (PEMS), or other system specified in this section to measure NO_x on an individual basis. Each NO_x monitor (CEMS or PEMS) is subject to the relative accuracy test audit relative accuracy requirements of 40 Code of Federal Regulations (CFR) Part 75, Appendix B, Figure 2, except the concentration options (parts per million by volume (ppmv) and pounds per million British thermal units) do not apply. Each NO_x monitor must meet either the relative accuracy percent requirement of 40 CFR Part 75, Appendix B, Figure 2, or an alternative relative accuracy requirement of ±2.0 ppmv from the reference method mean value.

(b) Carbon monoxide (CO) monitoring. The owner or operator shall monitor CO exhaust emissions from each unit subject to the emission specifications of this division using one or more of the methods specified in §117.8120 of this title (relating to Carbon Monoxide (CO) Monitoring).

(c) CEMS requirements. The owner or operator of any CEMS used to meet a pollutant monitoring requirement of this section shall comply with the requirements of §117.8110(a) of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources).

(d) Acid rain peaking units. The owner or operator of each peaking unit as defined in 40 CFR §72.2, may:

(1) monitor operating parameters for each unit in accordance with 40 CFR Part 75, Appendix E, §1.1 or §1.2 and calculate NO_x emission rates based on those procedures; or

(2) use CEMS or PEMS in accordance with this section to monitor NO_x emission rates.

(e) Auxiliary steam boilers. The owner or operator of each auxiliary steam boiler as defined in §117.10 of this title (relating to Definitions) shall:

(1) install, calibrate, maintain, and operate a CEMS in accordance with this section; or

(2) comply with the appropriate (considering boiler maximum rated capacity and annual heat input) industrial boiler monitoring requirements of §117.240 of this title (relating to Continuous Demonstration of Compliance).

(f) PEMS requirements. The owner or operator of any PEMS used to meet a pollutant monitoring requirement of this section shall comply with the following. The required PEMS and fuel flow meters must be used to demonstrate continuous compliance with the emission specifications of this division.

(1) The PEMS must predict the pollutant emissions in the units of the applicable emission specifications of this division.

(2) The PEMS must meet the requirements of §117.8110(b) of this title.

(g) Stationary gas turbine monitoring for NO_x reasonably available control technology (RACT). The owner or operator of each stationary gas turbine subject to the emission specifications of §117.1105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), instead of monitoring emissions in accordance with the monitoring requirements of 40 CFR Part 75, may comply with the following monitoring requirements:

(1) for stationary gas turbines rated less than 30 megawatts (MW) or peaking gas turbines (as defined in §117.10 of this title) that use steam or water injection to comply with the emission specifications of §117.1105(g) of this title:

(A) install, calibrate, maintain and operate a CEMS or PEMS in compliance with this section; or

(B) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. The system must be accurate to within ±5.0%. The steam-to-fuel or water-to-fuel ratio monitoring data must be used for demonstrating continuous compliance with the applicable emission specification of §117.1105 of this title; and

(2) for stationary gas turbines subject to the emission specifications of §117.1105(f) of this title, install, calibrate, maintain and operate a CEMS or PEMS in compliance with this section.

(h) Totalizing fuel flow meters. The owner or operator of units listed in this subsection shall install, calibrate, maintain, and operate totalizing fuel flow meters 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. In lieu of installing a totalizing fuel flow meter on a unit, an owner or operator may opt to assume fuel consumption at maximum design fuel flow rates during hours of the unit's operation. The units are:

(1) any unit subject to the emission specifications of this division;

(2) any stationary gas turbine with an MW rating greater than or equal to 1.0 MW operated more than 850 hours per year; and

(3) any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.1103(a)(2) of this title (relating to Exemptions).

(i) Run time meters. The owner or operator of any stationary gas turbine using the exemption of §117.1103(a)(3) or (b) of this title shall record the operating time with an elapsed run time meter approved by the executive director.

(j) Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemptions of §117.1103(a)(2) or (3) of this title, shall notify the executive director within seven days if the applicable limit 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.

(k) Data used for compliance. After the initial demonstration of compliance required by §117.1135 of this title (relating to Initial Demonstration of Compliance), the methods required in this section must be used to determine compliance with the emission specifications of §117.1105 of this title or §117.1110(a) of this title (relating to Emissions Specifications for Attainment Demonstration). Compliance with the emission specifications may also be determined at the discretion of the executive director using any commission compliance method.

(l) Enforcement of NO_x RACT limits. If compliance with §117.1105 of this title is selected, no unit subject to §117.1105 of this title may be operated at an emission rate higher than that allowed by the emission specifications of §117.1105 of this title. If compliance with §117.1115 of this title (relating to Alternative System-Wide Emission Specifications) is selected, no unit subject to §117.1115 of this title may be operated at an emission rate higher than that approved by the executive director in accordance with §117.1152 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology).

§117.1145. 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, 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 fuel burned; gross and net energy production in megawatt-hours (MW-hr); and the date, time, and duration of the event.

(b) Notification. The owner or operator of a unit subject to the emission specifications of this division (relating to Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources) 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 §117.1135 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) performance evaluation conducted under §117.1140 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 §117.1135 of this title or any CEMS or PEMS performance evaluation conducted under §117.1140 of this title:

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

(2) not later than the appropriate compliance schedules specified in §117.9110 of this title (relating to Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system under §117.1140 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission specifications in this division and the 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 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 §117.1140 of this title, excess emissions are computed as each one-hour period that the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial demonstration of compliance test required by §117.1135 of this title; and

(B) for utility boilers complying with §117.1120 of this title (relating to System 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 steam-to-fuel or water-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 or steam-to-fuel or water-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) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain records of the data specified in this subsection. Records must be kept for a period of at least five years and made available for inspection by the executive director, United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction upon request. Operating records for each unit must be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or for units claimed exempt from the emission specifications based on low annual capacity factor, monthly. Records must include:

(1) emission rates in units of the applicable standards;

(2) gross energy production in MW-hr (not applicable to auxiliary steam boilers);

(3) quantity and type of fuel burned;

(4) the injection rate of reactant chemicals (if applicable); and

(5) emission monitoring data, in accordance with §117.1140 of this title, including:

(A) the date, time, and duration of any malfunction in the operation of the monitoring system, except for zero and span checks, if applicable, and a description of system repairs and adjustments undertaken during each period;

(B) the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, PEMS, or operating parameter monitoring systems; and

(C) actual emissions or operating parameter measurements, as applicable;

(6) the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.1135 of this title; and

(7) records of hours of operation.

§117.1152. Final Control Plan Procedures for Reasonably Available Control Technology.

(a) The owner or operator of units listed in §117.1100 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.1105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)). The report must include a list of all units listed in §117.1100 of this title, showing:

(1) the NO_x emission specification resulting from application of §117.1105 of this title for each non-exempt unit;

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

(A) §117.1105 of this title;

(B) §117.1115 of this title (relating to Alternative System-Wide Emission Specifications);

(C) §117.1125 of this title (relating to Alternative Case Specific Specifications); or

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

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

(4) the emissions measured by testing required in §117.1135 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 §117.1135 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 Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources).

(b) For sources complying with §117.1115 of this title, in addition to the requirements of subsection (a) of this section, the owner or operator shall:

(1) assign to each affected unit the maximum NO_x emission rate, expressed in units of pounds per million British thermal units heat input on:

(A) a rolling 24-hour average and rolling 30-day average for gaseous fuel firing, and

(B) a rolling 24-hour average for oil or coal firing;

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

(A) the maximum allowable NO_x 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 system-wide average in accordance with §117.1115(e) of this title; and

(4) maintain a copy of the approved list of emission specifications for verification of continued compliance with the requirements of §117.1115 of this title.

(c) The report must be submitted by the applicable date specified for final control plans in §117.9110 of this title (relating to Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation 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 specification on a rolling 30-day average, according to the applicable schedule given in §117.9110 of this title.

§117.1154. Final Control Plan Procedures for Attainment Demonstration Emission Specifications.

(a) The owner or operator of utility boilers listed in §117.1100 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit to the executive director a final control report to show compliance with the requirements of §117.1110 of this title (relating to Emission Specifications for Attainment Demonstration). The report must include:

(1) the section under which NO_x compliance is being established for the utility boilers within the electric generating system, either:

(A) §117.1110 of this title; or

(B) §117.1120 of this title (relating to System Cap); and as applicable,

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

(2) the methods of NO_x control for each utility boiler;

(3) the emissions measured by testing required in §117.1135 of this title (relating to Initial Demonstration of Compliance);

(4) 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 §117.1135 of this title that is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any utility boiler with a claimed exemption from the emission specifications of §117.1110 of this title.

(b) For sources complying with §117.1120 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 system cap allowable emission rates;

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

(A) the average daily heat input, H_i, specified in §117.1120(c)(1) of this title;

(B) the maximum daily heat input, H_{mi}, specified in §117.1120(c)(2) of this title;

(C) the method of monitoring emissions; and

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

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

(c) The report must be submitted by the applicable date specified for final control plans in §117.9110 of this title (relating to Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation 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 §117.9110 of this title.

§117.1156. 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 emission specifications and the final compliance dates of this division (relating to Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources). For sources complying with §§117.1105, 117.1110, or 117.1115 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Emission Specifications for Attainment Demonstration; and Alternative System-Wide Emission Specifications), replacement new units may be included in the control plan. The revision of the final control plan is subject to the review and approval of the executive director.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 15, 2006.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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DIVISION 3. HOUSTON-GALVESTON-BRAZORIA OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

30 TAC §§117.1200, 117.1203, 117.1205, 117.1210, 117.1215, 117.1220, 117.1225, 117.1235, 117.1240, 117.1245, 117.1252, 117.1254, 117.1256

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.1200. Applicability.

(a) The provisions of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources) apply to utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners in turbine exhaust ducts used in an electric power generating system, as defined in §117.10 of this title (relating to Definitions), that is located within the Houston-Galveston-Brazoria ozone nonattainment area and is owned or operated by:

(1) a municipality or a Public Utility Commission of Texas (PUC) regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC; or

(2) an electric cooperative, independent power producer, municipality, river authority, or public utility.

(b) The provisions of this division are applicable for the life of each affected unit within an electric power generating system or until this division or sections of this title that are applicable to an affected unit are rescinded.

§117.1203. Exemptions.

(a) Reasonably available control technology. Units exempted from the provisions of §§117.1205, 117.1215, and 117.1240 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Alternative System-Wide Emission Specifications; and Continuous Demonstration of Compliance), except as specified in §117.1240(i) - (k) of this title, include the following:

(1) any new units placed into service after November 15, 1992;

(2) any utility boiler or auxiliary steam boiler with an annual heat input less than or equal to $2.2(10^{11})$ British thermal units per year; or

(3) stationary gas turbines and engines, that are:

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

(B) demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

(b) Emission specifications for attainment demonstration. Stationary gas turbines and engines that are used solely to power other engines or gas turbines during startups are exempt from the provisions of §§117.1210, 117.1220, and 117.1240 of this title (relating to Emission Specifications for Attainment Demonstration; System Cap; and Continuous Demonstration of Compliance), except as specified in §117.1240(j) of this title.

(c) Emergency fuel oil firing.

(1) The fuel oil firing emission specifications of §§117.1205(c), 117.1210(a)(1)(B), 117.1215(b), and 117.1220 of this title do not apply during an emergency operating condition declared by the Electric Reliability Council of Texas or the Southeastern Electric Reliability Council, or any other emergency operating condition that necessitates oil firing. All findings that emergency operating conditions exist are subject to the approval of the executive director.

(2) The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction verbal notification as soon as possible but no later than 48 hours after declaration of the emergency. Verbal notification must identify the anticipated date and time oil firing will begin, duration of the emergency period, affected oil-fired equipment, and quantity of oil to be fired in each unit, and must be followed by written notification containing this information no later than five days after declaration of the emergency.

(3) The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction final written notification as soon as possible but no later than two weeks after the termination of emergency fuel oil firing. Final written notification must identify the actual dates and times that oil firing began and ended, duration of the emergency period, affected oil-fired equipment, and quantity of oil fired in each unit.

§117.1205. Emission Specifications for Reasonably Available Control Technology (RACT).

(a) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, emissions of nitrogen oxides (NO_x) in excess of 0.26 pounds per million British thermal units (lb/MMBtu) heat input on a rolling 24-hour average and 0.20 lb/MMBtu heat input on a 30-day rolling average while firing natural gas or a combination of natural gas and waste oil.

(b) No person shall allow the discharge into the atmosphere from any utility boiler, NO_x emissions in excess of 0.38 lb/MMBtu heat input for tangentially-fired units on a rolling 24-hour averaging period or 0.43 lb/MMBtu heat input for wall-fired units on a rolling 24-hour averaging period while firing coal.

(c) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of 0.30 lb/MMBtu heat input on a rolling 24-hour averaging period while firing fuel oil only.

(d) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of the heat input weighted average of the applicable emission specifications specified in subsections (a) and (c) of this section on a rolling 24-hour averaging period while firing a mixture of natural gas and fuel oil, as follows:
Figure: 30 TAC §117.1205(d)

(e) Each auxiliary steam boiler that is an affected facility as defined by New Source Performance Standards (NSPS) 40 Code of Federal Regulations Part 60, Subparts D, Db, or Dc is limited to the applicable NSPS NO_x emission limit, unless the boiler is also subject to a more stringent permit emission limit, in which case the more stringent emission limit applies. Each auxiliary steam boiler subject to an emission specification under this subsection is not subject to the emission specifications of subsection (a), (c), or (d) of this section.

(f) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a megawatt (MW) rating greater than or equal to 30 MW and an annual electric output in megawatt-hours (MW-hr) of greater than or equal to the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of:

(1) 42 parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis, while firing natural gas; and

(2) 65 ppmv at 15% O_2, dry basis, while firing fuel oil.

(g) No person shall allow the discharge into the atmosphere from any stationary gas turbine used for peaking service with an annual electric output in MW-hr of less than the product of 2,500 hours and the MW rating of the unit NO_x emissions in excess of a block one-hour average of:

(1) 0.20 lb/MMBtu heat input while firing natural gas; and

(2) 0.30 lb/MMBtu heat input while firing fuel oil.

(h) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler subject to the NO_x emission specifications specified in subsections (a) - (e) of this section, carbon monoxide (CO) emissions in excess of 400 ppmv at 3.0% O_2, dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units, 0.31 lb/MMBtu heat input for oil-fired units, and 0.33 lb/MMBtu heat input for coal-fired units), based on:

(1) a one-hour average for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

(2) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO.

(i) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to 10 MW, CO emissions in excess of a block one-hour average of 132 ppmv at 15% O_2, dry basis.

(j) No person shall allow the discharge into the atmosphere from any unit subject to this section, ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(k) For purposes of this subchapter, the following apply.

(1) The lower of any permit NO_x 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 NO_x emission specifications of subsections (a) - (g) of this section apply, except that gas-fired boilers operating under a permit issued after March 3, 1982, with a NO_x emission limit of 0.12 lb/MMBtu heat input, are limited to that rate for the purposes of this subchapter.

(2) For any unit placed into service after June 9, 1993, and prior to the final compliance date as specified in §117.9120 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation 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 NO_x emission limit under a permit issued after June 9, 1993, in accordance with Chapter 116 of this title and the emission specifications of subsections (a) - (g) of this section apply. 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 specifications of §117.1215 of this title (relating to Alternative System-Wide Emission Specifications). Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

(l) This section no longer applies after the appropriate compliance date(s) for emission specifications for attainment demonstration given in §117.9120(2) of this title. For purposes of this subsection, this means that the reasonably available control technology (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.

§117.1210. Emission Specifications for Attainment Demonstration.

(a) Emission specifications for the Mass Emission Cap and Trade Program. The owner or operator of each utility boiler, auxiliary steam boiler, or stationary gas turbine shall ensure that emissions of nitrogen oxides (NO_x) do not exceed 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 rates, in pounds per million British thermal units (lb/MMBtu) heat input, on the basis of daily and 30-day averaging periods as specified in §117.1220 of this title (relating to System Cap), and as specified 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):

(1) utility boilers:

(A) gas-fired, 0.030; and

(B) coal-fired or oil-fired:

(i) wall-fired, 0.050; and

(ii) tangential-fired, 0.045;

(2) auxiliary steam boilers, 0.030; and

(3) stationary gas turbines (including duct burners used in turbine exhaust ducts), 0.032.

(b) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to subsection (a) of this section:

(1) carbon monoxide (CO) emissions in excess of 400 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units, 0.31 lb/MMBtu

heat input for oil-fired units, and 0.33 lb/MMBtu heat input for coal-fired units), based on:

(A) a one-hour average for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO; and

(2) for units that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions in excess of 10 ppmv, at 3.0% O_2, dry, for boilers and 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(c) Compliance flexibility.

(1) An owner or operator may petition the executive director for an alternative to the CO or ammonia specifications of this section in accordance with §117.1225 of this title (relating to Alternative Case Specific Specifications).

(2) Section 117.1215 of this title (relating to Alternative System-Wide Emission Specifications) and §117.1225 of this title are not alternative methods of compliance with the NO_x emission specifications of this section.

(3) For units that meet the definition of electric generating facility (EGF), the owner or operator shall use both the methods specified in §117.1220 of this title and the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title to comply with the NO_x emission specifications of this section. An owner or operator may use the alternative methods specified in §117.9800 of this title (relating to Use of Emission Credits for Compliance) for purposes of complying with §117.1220 of this title.

(4) For units that do not meet the definition of EGF, 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 NO_x emission specifications of this section.

§117.1215. Alternative System-Wide Emission Specifications.

(a) An owner or operator of any gaseous- or coal-fired utility boiler or stationary gas turbine may achieve compliance with the nitrogen oxides (NO_x) emission specifications of §117.1205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) by achieving compliance with a system-wide emission specification. Any owner or operator who elects to comply with system-wide emission specifications shall reduce emissions of NO_x from affected units so that, if all such units were operated at their maximum rated capacity, the system-wide emission rate from all units in the system as defined in §117.10 of this title (relating to Definitions) would not exceed the system-wide emission specification as defined in §117.10 of this title.

(1) The following units must comply with the individual emission specifications of §117.1205 of this title and must not be included in the system-wide emission specification:

(A) gas turbines used for peaking service subject to the emission specifications of §117.1205(g) of this title; and

(B) auxiliary steam boilers subject to the emission specifications of §117.1205(a), (c), (d), or (e) of this title.

(2) Coal-fired utility boilers must have a separate system average under this section, limited to those units.

(3) Oil-fired utility boilers must have a separate system average under this section, limited to those units. The NO_x emission specification assigned to each oil-fired unit in the system must not exceed 0.5 pounds per million British thermal units (lb/MMBtu) based on a rolling 24-hour average.

(b) The owner or operator shall establish enforceable emission limits for each affected unit in the system calculated in accordance with the maximum rated capacity averaging in this section as follows:

(1) for each gas-fired unit in the system, in lb/MMBtu:

(A) on a rolling 24-hour averaging period; and

(B) on a rolling 30-day averaging period;

(2) for each coal-fired unit in the system, in lb/MMBtu on a rolling 24-hour averaging period;

(3) for stationary gas turbines, in the units of the appropriate emission specification of §117.1205 of this title; and

(4) for each fuel oil-fired unit in the system, in lb/MMBtu on a rolling 24-hour averaging period.

(c) An owner or operator of any gaseous and liquid fuel-fired utility boiler or gas turbine shall:

(1) comply with the assigned maximum allowable emission rates for gas fuel while firing natural gas only;

(2) comply with the assigned maximum allowable emission rate for liquid fuel while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing, 24-hour average, allowable emission specification and the assigned liquid-firing allowable emission specification while operating on liquid and gaseous fuel concurrently.

(d) Solely for purposes of calculating the system-wide emission specification, the allowable mass emission rate for each affected unit must be calculated from the emission specifications of §117.1205 of this title, as follows.

(1) The NO_x emissions rate (in pounds per hour) for each affected utility boiler is determined by the following equation.
Figure: 30 TAC §117.1215(d)(1)

(2) The NO_x emissions rate (in pounds per hour) for each affected stationary gas turbine is determined by the following equations.
Figure: 30 TAC §117.1215(d)(2)

(e) This section no longer applies after the appropriate compliance date(s) for emission specifications for attainment demonstration given in §117.9120(2) of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources). For purposes of this subsection, this means that the alternative system-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 system-wide emission specifications of this section.

§117.1220. System Cap.

(a) An owner or operator of an electric generating facility (EGF) shall comply with a daily and 30-day system cap nitrogen oxides (NO_x) emission limitation in accordance with the requirements of this section.

(b) Each EGF within an electric power generating system, as defined in §117.10 of this title (relating to Definitions), that is subject to §117.1210(a) 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 must be calculated using the following equation.
Figure: 30 TAC §117.1220(c)(1)

(2) A maximum daily cap must be calculated using the following equation.
Figure: 30 TAC §117.1220(c)(2)

(3) Each EGF in the system cap is subject to the emission limits of both paragraphs (1) and (2) of this subsection at all times.

(d) The NO_x emissions monitoring required by §117.1240 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) Part 75, use the missing data procedures specified in 40 CFR Part 75, Subpart D (Missing Data Substitution Procedures); or

(B) 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);

(2) use 40 CFR Part 75, Appendix E monitoring in accordance with §117.1240(e) of this title;

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

(A) use the methods specified in 40 CFR Part 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) if the methods specified in paragraphs (1) - (3) of this subsection are not used, the owner or operator shall use the maximum block one-hour emission rate as measured by the 30-day testing.

(f) The owner or operator shall maintain daily records indicating the NO_x emissions and fuel usage from each EGF and summations of total NO_x emissions and fuel usage for all EGFs under the system cap on a daily basis. Records must also be retained in accordance with §117.1245 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(g) The owner or operator 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 §117.1245 of this title.

(h) The owner or operator shall demonstrate initial compliance with the system cap in accordance with the schedule specified in §117.9120 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation 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 NO_x emission rate measured by the NO_x monitor, if operating properly. If the NO_x monitor is not operating properly, the substitute data procedures identified in subsection (e) of this section must be used. If neither the NO_x 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.

(l) An owner or operator of a source of NO_x who is participating in the system cap under this section may exceed their system cap provided that the owner or operator is complying with the requirements of §117.9800 of this title (relating to Use of Emission Credits for Compliance) or Chapter 101, Subchapter H, Division 1, 4, or 5 of this title (relating to Emission Credit Banking and Trading; Discrete Emission Credit Banking and Trading; and System Cap Trading).

(m) In the event that a unit within an electric power generating system is sold or transferred, the unit must become subject to the transferee's system cap.

§117.1225. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.1205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), or the carbon monoxide (CO) or ammonia specifications of §117.1210(b) of this title (relating to Emission Specifications for Attainment Demonstration), the executive director may approve emission specifications different from §117.1205 of this title or the CO or ammonia specifications in §117.1210(b) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) shall determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.1205 or §117.1210 of this title, as applicable; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through system-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources).

§117.1235. Initial Demonstration of Compliance.

(a) The owner or operator of all units that are subject to this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources) shall test the units as follows.

(1) The units must be tested for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions.

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

(3) Testing must be performed in accordance with the schedules specified in §117.9120 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources).

(b) The tests required by subsection (a) of this section must be used for determination of initial compliance with the emission specifications of this division. Test results must be reported in the units of the applicable emission specifications and averaging periods. If compliance testing is based on 40 Code of Federal Regulations Part 60, Appendix A reference methods, the report must contain the information specified in §117.8010 of this title (relating to Compliance Stack Test Reports).

(c) Continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) required by §117.1240 of this title (relating to Continuous Demonstration of Compliance) must be installed and operational before testing under subsection (a) of this section. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(d) Initial compliance with the requirements of this division for units operating with CEMS or PEMS in accordance with §117.1240 of this title must be demonstrated after monitor certification testing using the NO_x CEMS or PEMS as follows.

(1) To comply with the NO_x emission specification in pounds per million British thermal units (lb/MMBtu) on a rolling 30-day average, NO_x emissions from a 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) To comply with the NO_x emission specification in lb/MMBtu on a rolling 24-hour average, NO_x emissions from a unit are monitored for 24 consecutive operating hours and the 24-hour average emission rate is used to determine compliance with the NO_x emission specification. The 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period. Compliance with the NO_x emission specification for fuel oil firing must be determined based on the first 24 consecutive operating hours a unit fires fuel oil.

(3) For any electric generating facility (EGF) complying with §117.1220 of this title (relating to System Cap), a rolling 30-day average of total daily pounds of NO_x emissions from the EGF must be monitored (or calculated in accordance with §117.1220(e) of this title) for 30 successive system 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 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.

(4) To comply with the NO_x emission specification in pounds per hour or parts per million by volume (ppmv) at 15% O_2 dry basis, on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable, after CEMS or PEMS certification testing required in §117.1240 of this title is used to determine compliance with the NO_x emission specification.

(5) To comply with the CO emission specification in ppmv on a rolling 24-hour average, CO emissions from a unit are monitored for 24 consecutive hours and the rolling 24-hour average emission rate is used to determine compliance with the CO emission specification. The rolling 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period.

§117.1240. Continuous Demonstration of Compliance.

(a) Nitrogen oxides (NO_x) monitoring. The owner or operator of each unit subject to this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources), shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS), predictive emissions monitoring system (PEMS), or other system specified in this section to measure NO_x on an individual basis. Each NO_x monitor (CEMS or PEMS) is subject to the relative accuracy test audit relative accuracy requirements of 40 Code of Federal Regulations (CFR) Part 75, Appendix B, Figure 2, except the concentration options (parts per million by volume (ppmv) and pounds per million British thermal units) therein do not apply. Each NO_x monitor must meet either the relative accuracy percent requirement of 40 CFR Part 75, Appendix B, Figure 2, or an alternative relative accuracy requirement of ±2.0 ppmv from the reference method mean value.

(b) Carbon monoxide (CO) monitoring. The owner or operator shall monitor CO exhaust emissions from each unit subject to this division using one or more of the methods in §117.8120 of this title (relating to Carbon Monoxide (CO) Monitoring).

(c) Ammonia monitoring requirements. The owner or operator of units that are subject to the ammonia emission specification in §117.1210(b)(2) of this title (relating to Emission Specifications for Attainment Demonstration) shall comply with the ammonia monitoring requirements of §117.8130 of this title (relating to Ammonia Monitoring).

(d) CEMS requirements.

(1) For units subject to §117.1205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), any CEMS required by this section must comply with the requirements of §117.8110(a) of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources).

(2) The owner or operator of any unit subject to §117.1210 of this title shall comply with the following:

(A) any CEMS required by this section must comply with the requirements of §117.8110(a)(1) of this title;

(B) all bypass stacks must be monitored in order to quantify emissions directed through the bypass stack;

(C) one CEMS may be shared among units, provided:

(i) the exhaust stream of each stack is analyzed separately; and

(ii) the CEMS meets the certification requirements of §117.8110(a)(1) of this title for each stack while the CEMS is operating in the time-shared mode; and

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

(e) Acid rain peaking units. The owner or operator of each peaking unit as defined in 40 CFR §72.2, may:

(1) monitor operating parameters for each unit in accordance with 40 CFR Part 75, Appendix E, §1.1 or §1.2 and calculate NO_x emission rates based on those procedures; or

(2) use CEMS or PEMS in accordance with this section to monitor NO_x emission rates.

(f) Auxiliary steam boilers. The owner or operator of each auxiliary steam boiler as defined in §117.10 of this title (relating to Definitions) shall:

(1) install, calibrate, maintain, and operate a CEMS in accordance with this section; or

(2) comply with the appropriate (considering boiler maximum rated capacity and annual heat input) industrial boiler monitoring requirements of §117.340 of this title (relating to Continuous Demonstration of Compliance).

(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. The required PEMS and fuel flow meters must be used to demonstrate continuous compliance with the requirements of this division.

(1) The PEMS must predict the pollutant emissions in the units of the applicable emission limitations of this division.

(2) The PEMS must meet the requirements of §117.8110(b) of this title.

(h) Stationary gas turbine monitoring for NO_x RACT. The owner or operator of each stationary gas turbine subject to the emission specifications of §117.1205 of this title, instead of monitoring emissions in accordance with the monitoring requirements of 40 CFR Part 75, may comply with the following monitoring requirements:

(1) for stationary gas turbines rated less than 30 megawatts or peaking gas turbines (as defined in §117.10 of this title) that use steam or water injection to comply with the emission specifications of §117.1205(g) of this title:

(A) install, calibrate, maintain and operate a CEMS or PEMS in compliance with this section; or

(B) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. The system must be accurate to within ±5.0%. The steam-to-fuel or water-to-fuel ratio monitoring data must be used for demonstrating continuous compliance with the applicable emission specification of §117.1205 of this title; and

(2) for stationary gas turbines subject to the emission specifications of §117.1205(f) of this title, install, calibrate, maintain and operate a CEMS or PEMS in compliance with this section.

(i) Totalizing fuel flow meters. The owner or operator of units listed in this subsection shall install, calibrate, maintain, and operate totalizing fuel flow meters 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. In lieu of installing a totalizing fuel flow meter on a unit, an owner or operator may opt to assume fuel consumption at maximum design fuel flow rates during hours of the unit's operation. The units are:

(1) for units subject to §117.1205 of this title:

(A) any unit subject to the emission specifications of this division;

(B) any stationary gas turbine with an MW rating greater than or equal to 1.0 MW operated more than 850 hours per year; and

(C) any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.1203(a)(2) of this title (relating to Exemptions); and

(2) for units subject to §117.1210 of this title:

(A) utility boilers;

(B) auxiliary steam boilers; and

(C) stationary gas turbines.

(j) Run time meters. The owner or operator of any stationary gas turbine using the exemption of §117.1203(a)(3) or (b) of this title shall record the operating time with an elapsed run time meter approved by the executive director.

(k) Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemptions of §117.1203(a)(2) or (3) of this title, shall notify the executive director within seven days if the applicable limit 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.

(l) Data used for compliance.

(1) After the initial demonstration of compliance required by §117.1235 of this title (relating to Initial Demonstration of Compliance), the methods required in this section must be used to determine compliance with the emission specifications of §117.1205 of this title. Compliance with the emission specification may also be determined at the discretion of the executive director using any commission compliance method.

(2) For units subject to §117.1210(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 requirements.

(m) Enforcement of NO_x RACT limits. If compliance with §117.1205 of this title is selected, no unit subject to §117.1205 of this title may be operated at an emission rate higher than that allowed by the emission specifications of §117.1205 of this title. If compliance with §117.1215 of this title (relating to Alternative System-Wide Emission Specifications) is selected, no unit subject to §117.1215 of this title may be operated at an emission rate higher than that approved by the executive director in accordance with §117.1252(b) of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology).

(n) Testing requirements. The owner or operator of units subject to §117.1210(a) of this title must test the units as specified in §117.1235 of this title in accordance with the schedule specified in §117.9120(2) of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources).

(o) Emission allowances. The owner or operator of units subject to §117.1210(a) of this title shall comply with the following.

(1) The NO_x testing and monitoring data of subsections (a), (i), and (n) 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.

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

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

(B) Retesting as specified in subsection (n) 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 NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation, and fuel-lean and conventional (fuel-rich) reburn.

(C) The NO_x emission rate determined by the retesting must establish a new emission factor to be used 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.

§117.1245. 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, 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 fuel burned; gross and net energy production in megawatt-hours (MW-hr); and the date, time, and duration of the event.

(b) Notification. The owner or operator of a unit subject to the emission specifications of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources) 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 §117.1235 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) performance evaluation conducted under §117.1240 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 §117.1235 of this title or any CEMS or PEMS performance evaluation conducted under §117.1240 of this title:

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

(2) not later than the appropriate compliance schedules specified in §117.9120 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system under §117.1240 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations in this division and the 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 computed in accordance with 40 Code of Federal Regulations (CFR) §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 §117.1240 of this title, excess emissions are computed as each one-hour period that the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial demonstration of compliance test required by §117.1235 of this title; and

(B) for utility boilers complying with §117.1220 of this title (relating to System 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 steam-to-fuel or water-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 or steam-to-fuel or water-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) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain records of the data specified in this subsection. Records must be kept for a period of at least five years and made available for inspection by the executive director, United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction upon request. Operating records for each unit must be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or for units claimed exempt from the emission specifications based on low annual capacity factor, monthly. Records must include:

(1) emission rates in units of the applicable standards;

(2) gross energy production in MW-hr (not applicable to auxiliary steam boilers);

(3) quantity and type of fuel burned;

(4) the injection rate of reactant chemicals (if applicable); and

(5) emission monitoring data, in accordance with §117.1240 of this title, including:

(A) the date, time, and duration of any malfunction in the operation of the monitoring system, except for zero and span checks, if applicable, and a description of system repairs and adjustments undertaken during each period;

(B) the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, PEMS, or operating parameter monitoring systems; and

(C) actual emissions or operating parameter measurements, as applicable;

(6) the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.1235 of this title;

(7) records of hours of operation; and

(8) for units subject to the ammonia monitoring requirements of §117.1240(c) 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 NO_x stack emissions measured during each sorbent or stain tube test.

§117.1252. Final Control Plan Procedures for Reasonably Available Control Technology.

(a) The owner or operator of units listed in §117.1200 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.1205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)). The report must include a list of all units listed in §117.1200 of this title, showing:

(1) the NO_x emission specification resulting from application of §117.1205 of this title for each non-exempt unit;

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

(A) §117.1205 of this title;

(B) §117.1215 of this title (relating to Alternative System-Wide Emission Specifications);

(C) §117.1225 of this title (relating to Alternative Case Specific Specifications); or

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

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

(4) the emissions measured by testing required in §117.1235 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 §117.1235 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.

(b) For sources complying with §117.1215 of this title, in addition to the requirements of subsection (a) of this section, the owner or operator shall:

(1) assign to each affected unit the maximum NO_x emission rate, expressed in units of pounds per million British thermal units heat input on:

(A) a rolling 24-hour average and rolling 30-day average for gaseous fuel firing; and

(B) a rolling 24-hour average for oil or coal firing;

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

(A) the maximum allowable NO_x 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 system-wide average in accordance with §117.1215(e) of this title; and

(4) maintain a copy of the approved list of emission limits for verification of continued compliance with the requirements of §117.1215 of this title.

(c) The report must be submitted by the applicable date specified for final control plans in §117.9120 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation 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 §117.9120 of this title.

§117.1254. Final Control Plan Procedures for Attainment Demonstration Emission Specifications.

(a) The owner or operator of utility boilers listed in §117.1200 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit to the executive director a final control report to show compliance with the requirements of §117.1210 of this title (relating to Emission Specifications for Attainment Demonstration). The report must include:

(1) the section under which NO_x compliance is being established for the utility boilers within the electric generating system, either:

(A) Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program); and

(B) §117.1220 of this title (relating to System Cap); and as applicable,

(C) §117.9800 of this title (relating to Use of Emission Credits for Compliance).

(2) the methods of NO_x control for each utility boiler;

(3) the emissions measured by testing required in §117.1235 of this title (relating to Initial Demonstration of Compliance);

(4) 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 §117.1235 of this title that is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any utility boiler with a claimed exemption from the emission specifications of §117.1210 of this title.

(b) For sources complying with §117.1220 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 system cap allowable emission rates;

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

(A) the average daily heat input, H_i, specified in §117.1220(c)(1) of this title;

(B) the maximum daily heat input, H_{mi}, specified in §117.1220(c)(2) of this title;

(C) the method of monitoring emissions; and

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

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

(c) The report must be submitted by the applicable date specified for final control plans in §117.9120 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation 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 §117.9120 of this title.

§117.1256. 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 Utility Electric Generation Sources). For sources complying with §§117.1205, 117.1210, or 117.1215 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Emission Specifications for Attainment Demonstration; and Alternative System-Wide Emission Specifications), replacement new units may be included in the control plan. The revision of the final control plan is subject to the review and approval of the executive director.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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DIVISION 4. DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

30 TAC §§117.1300, 117.1303, 117.1310, 117.1325, 117.1335, 117.1340, 117.1345, 117.1350, 117.1354, 117.1356

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.1300. Applicability.

(a) The provisions of this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources) apply to utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in turbine exhaust ducts used in an electric power generating system, as defined in §117.10 of this title (relating to Definitions) and that is located within the Dallas-Fort Worth eight-hour ozone nonattainment area and is owned or operated by:

(1) a municipality or a Public Utility Commission of Texas (PUC) regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC; or

(2) an electric cooperative, independent power producer, municipality, river authority, or public utility.

(b) The provisions of this division are applicable for the life of each affected unit within an electric power generating system or until this division or sections of this title that are applicable to an affected unit are rescinded.

§117.1303. Exemptions.

(a) Emission specifications for attainment demonstrations. Units exempt from the provisions of §117.1310 and §117.1340 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration; and Continuous Demonstration of Compliance), except as specified in §117.1340(i) or (j) of this title, include the following:

(1) any new auxiliary steam boiler or stationary gas turbines placed into service after November 15, 1992;

(2) any auxiliary steam boiler with an annual heat input less than or equal to $2.2(10^{11})$ British thermal units per year; or

(3) stationary gas turbines and engines that are:

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

(B) demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

(b) Emergency fuel oil firing.

(1) The emissions specifications of §117.1310 of this title do not apply during an emergency operating condition declared by the Electric Reliability Council of Texas, or any other emergency operating condition that necessitates oil firing. All findings that emergency operating conditions exist are subject to the approval of the executive director.

(2) The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction verbal notification as soon as possible but no later than 48 hours after declaration of the emergency. Verbal notification must identify the anticipated date and time oil firing will begin, duration of the emergency period, affected oil-fired equipment, and quantity of oil to be fired in each unit, and must be followed by written notification containing this information no later than five days after declaration of the emergency.

(3) The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction final written notification as soon as possible but no later than two weeks after the termination of emergency fuel oil firing. Final written notification must identify the actual dates and times that oil firing began and ended, duration of the emergency period, affected oil-fired equipment, and quantity of oil fired in each unit.

§117.1310. Emission Specifications for Eight-Hour Attainment Demonstration.

(a) Nitrogen oxides (NO_x) emission specifications. The owner or operator of any utility boiler, auxiliary steam boiler, or stationary gas turbine subject to this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources) shall not allow the discharge into the atmosphere, emissions of NO_x in excess of the following:

(1) utility boilers:

(A) 0.06 pounds per million British thermal units (lb/MMBtu) heat input from utility boilers that are part of a small utility system, as defined in §117.10 of this title (relating to Definitions):

(i) on a rolling 24-hour average basis during the months of March through October of each calendar year; and

(ii) on a rolling 30-day average basis during the months of November, December, January, and February of each calendar year;

(B) 0.033 lb/MMBtu heat input from utility boilers that are part of a large utility system, as defined in §117.10 of this title:

(i) on a rolling 24-hour average basis during the months of March through October of each calendar year; and

(ii) on a rolling 30-day average basis during the months of November, December, January, and February of each calendar year; or

(C) 0.50 pounds per megawatt-hour output on an annual average basis;

(2) auxiliary steam boilers:

(A) 0.26 lb/MMBtu heat input on a rolling 24-hour average and 0.20 lb/MMBtu heat input on a 30-day rolling average while firing natural gas or a combination of natural gas and waste oil;

(B) 0.30 lb/MMBtu heat input on a rolling 24-hour averaging period while firing fuel oil only;

(C) the heat input weighted average of the applicable emission specifications specified in subparagraphs (A) and (B) of this paragraph on a rolling 24-hour averaging period while firing a mixture of natural gas and fuel oil, as follows:
Figure: 30 TAC §117.1310(a)(2)(C)

(D) for each auxiliary steam boiler that is an affected facility as defined by New Source Performance Standards (NSPS) 40 Code of Federal Regulations Part 60, Subparts D, Db, or Dc, the applicable NSPS NO_x emission limit, unless the boiler is also subject to a more stringent permit emission limit, in which case the more stringent emission limit applies. Each auxiliary steam boiler subject to an emission specification under this subparagraph is not subject to the emission specifications of subparagraphs (A), (B), or (C) of this paragraph.

(3) stationary gas turbines:

(A) with a megawatt (MW) rating greater than or equal to 30 MW and an annual electric output in megawatt-hr (MW-hr) of greater than or equal to the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of:

(i) 42 parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis, while firing natural gas; and

(ii) 65 ppmv at 15% O_2, dry basis, while firing fuel oil; and

(B) used for peaking service with an annual electric output in MW-hr of less than the product of 2,500 hours and the MW rating of the unit NO_x emissions in excess of a block one-hour average of:

(i) 0.20 lb/MMBtu heat input while firing natural gas; and

(ii) 0.30 lb/MMBtu heat input while firing fuel oil.

(b) Related emissions. The owner or operator of any unit subject to the emission specifications of subsection (a) of this section shall not allow emission in excess of the following, except as provided in §117.1325 of this title (relating to Alternative Case Specific Specifications):

(1) carbon monoxide (CO):

(A) for utility boilers or auxiliary steam boilers, 400 ppmv at 3.0% O_2, dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units and 0.31 lb/MMBtu heat input for oil-fired units), based on:

(i) a one-hour average for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

(ii) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO; and

(B) for any stationary gas turbine with a MW rating greater than or equal to 10 MW, CO emissions in excess of a block one-hour average of 132 ppmv at 15% O_2, dry basis; and

(2) ammonia:

(A) for units that inject urea or ammonia into the exhaust stream for NO_x control, 10 ppmv, at 3.0% O_2, dry, for boilers and 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), based on:

(i) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(ii) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia; and

(B) for all other units, 20 ppmv based on a block one-hour averaging period.

(c) Compliance flexibility.

(1) An owner or operator may use §117.9800 of this title (relating to Use of Emission Credits for Compliance) to comply with the NO_x emission specifications of this section.

(2) Section 117.1325 of this title is not an applicable method of compliance with the NO_x emission specifications of this section.

(3) An owner or operator may petition the executive director for an alternative to the CO or ammonia specifications of this section in accordance with §117.1325 of this title.

§117.1325. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements the carbon monoxide (CO) or ammonia emission specifications of §117.1310(b) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration), the executive director may approve emission specifications different from the CO or ammonia specifications in §117.1310(b) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) shall determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.1310 of this title, as applicable; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through system-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources).

§117.1335. Initial Demonstration of Compliance.

(a) The owner or operator of all units subject to the emission specifications of this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources) shall test the units as follows.

(1) The units must be tested for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions.

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

(3) Testing must be performed in accordance with the schedules specified in §117.9130 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources).

(b) The tests required by subsection (a) of this section must be used for determination of initial compliance with the emission specifications of this division. Test results must be reported in the units of the applicable emission specifications and averaging periods. If compliance testing is based on 40 Code of Federal Regulations Part 60, Appendix A reference methods, the report must contain the information specified in §117.8010 of this title (relating to Compliance Stack Test Reports).

(c) Continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) required by §117.1340 of this title (relating to Continuous Demonstration of Compliance) must be installed and operational before testing under subsection (a) of this section. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(d) Initial compliance with the emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.1340 of this title must be demonstrated after monitor certification testing using the NO_x CEMS or PEMS as follows.

(1) To comply with the NO_x emission specification in pounds per million British thermal units (lb/MMBtu) on a rolling 30-day average, NO_x emissions from a 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) To comply with the NO_x emission specification in lb/MMBtu on a rolling 24-hour average, NO_x emissions from a unit are monitored for 24 consecutive operating hours and the 24-hour average emission rate is used to determine compliance with the NO_x emission specification. The 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period. Compliance with the NO_x emission specification for fuel oil firing must be determined based on the first 24 consecutive operating hours a unit fires fuel oil.

(3) To comply with the NO_x emission specification in pounds per hour or parts per million by volume at 15% O_2 dry basis, on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable, after CEMS or PEMS certification testing required in §117.1340 of this title is used to determine compliance with the NO_x emission specification.

(4) To comply with the NO_x emission specification in pounds per megawatt-hour output on an annual average basis, NO_x emissions from the unit are monitored in accordance with §117.1340(a) and (k) of this title. The annual average is calculated as the average of all hourly emission data recorded by the monitoring system. The averaging period for demonstrating initial compliance with the emission specification in §117.1310(a)(1)(C) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) is from March 1, 2009, through February 28, 2010.

(5) To comply with the CO emission specification in parts per million by volume on a rolling 24-hour average, CO emissions from a unit are monitored for 24 consecutive hours and the rolling 24-hour average emission rate is used to determine compliance with the CO emission specification. The rolling 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period.

§117.1340. Continuous Demonstration of Compliance.

(a) Nitrogen oxides (NO_x) monitoring. The owner or operator of each unit subject to the emission specifications of this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources), shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS), predictive emissions monitoring system (PEMS), or other system specified in this section to measure NO_x on an individual basis. Each NO_x monitor (CEMS or PEMS) is subject to the relative accuracy test audit relative accuracy requirements of 40 Code of Federal Regulations (CFR) Part 75, Appendix B, Figure 2, except the concentration options (parts per million by volume (ppmv) and pound per million British thermal units (lb/MMBtu)) do not apply. Each NO_x monitor must meet either the relative accuracy percent requirement of 40 CFR Part 75, Appendix B, Figure 2, or an alternative relative accuracy requirement of ±2.0 ppmv from the reference method mean value.

(b) Carbon monoxide (CO) monitoring. The owner or operator shall monitor CO exhaust emissions from each unit subject to the emission specifications of this division using one or more of the methods specified in §117.8120 of this title (relating to Carbon Monoxide (CO) Monitoring).

(c) Ammonia monitoring requirements. The owner or operator of units that are subject to the ammonia emission specification of §117.1310(b)(2)(A) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) shall comply with the ammonia monitoring requirements of §117.8130 of this title (relating to Ammonia Monitoring).

(d) CEMS requirements. The owner or operator of any CEMS used to meet a pollutant monitoring requirement of this section shall comply with the requirements of §117.8110(a) of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources).

(e) Acid rain peaking units. The owner or operator of each peaking unit as defined in 40 CFR §72.2, may:

(1) monitor operating parameters for each unit in accordance with 40 CFR Part 75, Appendix E, §1.1 or §1.2 and calculate NO_x emission rates based on those procedures; or

(2) use CEMS or PEMS in accordance with this section to monitor NO_x emission rates.

(f) Auxiliary steam boilers. The owner or operator of each auxiliary steam boiler shall:

(1) install, calibrate, maintain, and operate a CEMS in accordance with this section; or

(2) comply with the appropriate (considering boiler maximum rated capacity and annual heat input) industrial boiler monitoring requirements of §117.440 of this title (relating to Continuous Demonstration of Compliance).

(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. The required PEMS and fuel flow meters must be used to demonstrate continuous compliance with the emission specifications of this division.

(1) The PEMS must predict the pollutant emissions in the units of the applicable emission limitations of this division.

(2) The PEMS must meet the requirements of §117.8110(b) of this title.

(h) Stationary gas turbine monitoring. The owner or operator of each stationary gas turbine subject to the emission specifications of §117.1310 of this title, instead of monitoring emissions in accordance with the monitoring requirements of 40 CFR Part 75, may comply with the following monitoring requirements:

(1) for stationary gas turbines rated less than 30 megawatts (MW) or peaking gas turbines (as defined in §117.10 of this title (relating to Definitions)) that use steam or water injection to comply with the emission specifications of §117.1310(a)(3) of this title:

(A) install, calibrate, maintain and operate a CEMS or PEMS in compliance with this section; or

(B) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. The system must be accurate to within ±5.0%. The steam-to-fuel or water-to-fuel ratio monitoring data must be used for demonstrating continuous compliance with the applicable emission specification of §117.1310 of this title; and

(2) for stationary gas turbines subject to the emission specifications of §117.1310 of this title, install, calibrate, maintain, and operate a CEMS or PEMS in compliance with this section.

(i) Totalizing fuel flow meters. The owner or operator of units listed in this subsection shall install, calibrate, maintain, and operate totalizing fuel flow meters 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. In lieu of installing a totalizing fuel flow meter on a unit, an owner or operator may opt to assume fuel consumption at maximum design fuel flow rates during hours of the unit's operation. The units are:

(1) any unit subject to the emission specifications of §117.1310 of this title;

(2) any stationary gas turbine with an MW rating greater than or equal to 1.0 MW operated more than 850 hours per year; and

(3) any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.1303(a)(2) of this title (relating to Exemptions).

(j) Run time meters. The owner or operator of any stationary gas turbine using the exemption of §117.1303(a)(3) of this title shall record the operating time with an elapsed run time meter.

(k) Monitoring for output-based NO_x emission specification. The owner or operator of any unit that complies with the optional output-based NO_x emission specification in §117.1310(a)(1)(C) of this title, shall comply with the following:

(1) install, calibrate, maintain, and operate a system to continuously monitor, at least once every 15 minutes, and record the gross energy production of the unit in megawatt-hours;

(2) for each hour of operation, determine the total mass emission of NO_x, in pounds, from the unit using the NO_x monitoring requirements of subsection (a) of this section and the fuel monitoring requirements of subsection (i) of this section; and

(3) for each hour of operation, calculate and record the NO_x emissions in pounds per megawatt-hour using the monitoring specified in paragraphs (1) and (2) of this subsection.

(l) Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the exemptions in §117.1303(a)(2) or (3) of this title, shall notify the executive director within seven days if the applicable limit 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.

(m) Data used for compliance. After the initial demonstration of compliance required by §117.1335 of this title (relating to Initial Demonstration of Compliance), the methods required in this section must be used to determine compliance with the emission specifications of §117.1310 of this title. Compliance with the emission specifications may also be determined at the discretion of the executive director using any commission compliance method.

§117.1345. 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, 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 fuel burned; gross and net energy production in megawatt-hours (MW-hr); and the date, time, and duration of the event.

(b) Notification. The owner or operator of a unit subject to the emission specifications of this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources) shall submit notification to the appropriate regional office and any local air pollution control agency having jurisdiction as follows:

(1) written notification of the date of any testing conducted under §117.1335 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date; and

(2) written notification of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) performance evaluation conducted under §117.1340 of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date.

(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 §117.1335 of this title or any CEMS or PEMS performance evaluation conducted under §117.1340 of this title:

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

(2) not later than the appropriate compliance schedules specified in §117.9130 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system under §117.1340 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations in this division and the 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 computed in accordance with 40 Code of Federal Regulations (CFR) §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. For stationary gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.1340 of this title, excess emissions are computed as each one-hour period that the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial demonstration of compliance test required by §117.1335 of this title;

(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 steam-to-fuel or water-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 or steam-to-fuel or water-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) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain records of the data specified in this subsection. Records must be kept for a period of at least five years and made available for inspection by the executive director, United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction upon request. Operating records for each unit must be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or for units claimed exempt from the emission specifications based on low annual capacity factor, monthly. Records must include:

(1) emission rates in units of the applicable standards;

(2) gross energy production in MW-hr (not applicable to auxiliary steam boilers), except as specified in paragraph (8) of this subsection;

(3) quantity and type of fuel burned;

(4) the injection rate of reactant chemicals (if applicable); and

(5) emission monitoring data, in accordance with §117.1340 of this title, including:

(A) the date, time, and duration of any malfunction in the operation of the monitoring system, except for zero and span checks, if applicable, and a description of system repairs and adjustments undertaken during each period;

(B) the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, PEMS, or operating parameter monitoring systems; and

(C) actual emissions or operating parameter measurements, as applicable;

(6) the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.1335 of this title;

(7) records of hours of operation; and

(8) for any unit that the owner or operator elects to comply with the output-based emission specification in §117.1310(a)(1)(C) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration):

(A) hourly records of the gross energy production in MW-hr;

(B) records of hourly and annual average NO_x emissions in pounds per megawatt-hour (lb/MW-hr); and

(C) the averaging period for the annual average NO_x emissions in lb/MW-hr, for demonstrating continuous compliance is from January 1 through December 31 of each calendar year, beginning on January 1, 2010.

§117.1350. Initial Control Plan Procedures.

(a) The owner or operator of any unit at a major source of nitrogen oxides (NO_x) in the Dallas-Fort Worth eight-hour ozone nonattainment area that is subject to §117.1310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) shall submit an initial control plan. The control plan must include:

(1) a list of all combustion units at the account that are listed in §117.1310 of this title. The list must include for each unit:

(A) the maximum rated capacity;

(B) anticipated annual capacity factor;

(C) estimated or measured NO_x emission data in the units associated with the category of equipment from §117.1310 of this title;

(D) the method of determination for the NO_x emission data required by subparagraph (C) of this paragraph;

(E) the facility identification number and emission point number as submitted to the Industrial Emissions Assessment Section of the commission; and

(F) the emission point number as listed on the Maximum Allowable Emissions Rate Table of any applicable commission permit;

(2) identification of all units with a claimed exemption from the emission specifications §117.1310 of this title and the rule basis for the claimed exemption;

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

(4) for units required to install totalizing fuel flow meters in accordance with §117.1340 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; and

(5) for units required to install continuous emissions monitoring systems or predictive emissions monitoring systems in accordance with §117.1340 of this title, 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.

(b) The initial control plan must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Chief Engineer's Office by the applicable date specified for initial control plans in §117.9130 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources).

(c) For units located in Dallas, Denton, Collin, and Tarrant Counties subject to §117.1110 of this title (relating to Emission Specifications for Attainment Demonstration), the owner or operator may elect to submit the most recent revision of the final control plan required by §117.1154 of this title (relating to Final Control Plan Procedures for

Attainment Demonstration Emission Specifications) in lieu of the initial control plan required by subsection (a) of this section.

§117.1354. Final Control Plan Procedures for Attainment Demonstration Emission Specifications.

(a) The owner or operator of utility boilers listed in §117.1300 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit to the Office of Compliance and Enforcement, the appropriate regional office, and the Chief Engineer's Office, a final control report to show compliance with the requirements of §117.1310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration). The report must include:

(1) the methods of NO_x control for each utility boiler;

(2) the emissions measured by testing required in §117.1335 of this title (relating to Initial Demonstration of Compliance);

(3) 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 §117.1335 of this title that is not being submitted concurrently with the final compliance report; and

(4) the specific rule citation for any utility boiler with a claimed exemption from the emission specification of §117.1310 of this title.

(b) The report must be submitted by the applicable date specified for final control plans in §117.9130 of this title (relating to Compliance Schedule Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources).

§117.1356. 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 emission specifications and the final compliance dates of this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources). Replacement new units may be included in the control plan. The revision of the final control plan is subject to the review and approval of the executive director.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 15, 2006.

TRD-200606722
Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
Earliest possible date of adoption: January 28, 2007
For further information, please call: (512) 239-5017

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SUBCHAPTER D. COMBUSTION CONTROL AT MINOR SOURCES IN OZONE NONATTAINMENT AREAS DIVISION 1. HOUSTON-GALVESTON-BRAZORIA OZONE NONATTAINMENT AREA MINOR SOURCES

30 TAC §§117.2000, 117.2003, 117.2010, 117.2025, 117.2030, 117.2035, 117.2045

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.2000. Applicability.

This division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Minor Sources) applies in the Houston-Galveston-Brazoria ozone nonattainment area to the following equipment at any stationary source of nitrogen oxides (NO_x) that is not a major source of NO_x:

(1) boilers and process heaters;

(2) stationary, reciprocating internal combustion engines; and

(3) stationary gas turbines, including duct burners.

§117.2003. Exemptions.

(a) This division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Minor Sources) does not apply to the following, except as specified in §§117.2030(c), 117.2035(g), and 117.2045(b) and (c) of this title (relating to Operating Requirements; Monitoring and Testing Requirements; and Recordkeeping and Reporting Requirements):

(1) boilers and process heaters with a maximum rated capacity of 2.0 million British thermal units per hour (MMBtu/hr) or less;

(2) the following stationary engines:

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

(B) engines used in research and testing;

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

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

(E) engines operated 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;

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

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

(H) diesel engines placed into service before October 1, 2001, that:

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

(ii) have not been modified, reconstructed, or relocated on or after October 1, 2001. For the purposes of this clause, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

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

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

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

(3) stationary gas turbines rated at less than 1.0 megawatt with initial start of operation on or before October 1, 2001.

(b) At any stationary source of nitrogen oxides that is not subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the following are exempt from the requirements of this division, except for the totalizing fuel flow requirements of §117.2035(a) and (d) and §117.2045(a)(1) of this title:

(1) any boiler or process heater with a maximum rated capacity greater than 2.0 MMBtu/hr and less than 5.0 MMBtu/hr that has an annual heat input less than or equal to 1.8 (10^9) British thermal units (Btu) per calendar year; and

(2) any boiler or process heater with a maximum rated capacity equal to or greater than 5.0 MMBtu/hr that has an annual heat input less than or equal to 9.0 (10^9) Btu per calendar year.

§117.2010. Emission Specifications.

(a) For sources that are subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions 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 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 emission specifications in subsection (c) of this section. The averaging time must be as specified in Chapter 101, Subchapter H, Division 3 of this title.

(b) For sources that are not subject to Chapter 101, Subchapter H, Division 3 of this title, NO_x emissions are limited to 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 emission specifications in subsection (c) of this section. The averaging time must be as follows:

(1) if the unit is operated with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.2035(c) of this title (relating to Monitoring and Testing Requirements), either as:

(A) a rolling 30-day average period, in the units of the applicable standard;

(B) a block one-hour average, in the units of the applicable standard; or

(C) a block one-hour average, in pounds per hour, for boilers and process heaters, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in pounds per million British thermal units (lb/MMBtu); or

(2) if the unit is not operated with a NO_x CEMS or PEMS under §117.2035(c) of this title, a block one-hour average, in the units of the applicable standard.

(c) The following NO_x emission specifications must be used in conjunction with subsection (a) of this section to determine allocations for Chapter 101, Subchapter H, Division 3 of this title, or in conjunction with subsection (b) of this section to establish unit-by-unit emission specifications, as appropriate:

(1) from boilers and process heaters:

(A) gas-fired, 0.036 lb/MMBtu heat input (or alternatively, 30 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry basis); and

(B) liquid-fired, 0.072 lb/MMBtu heat input (or alternatively, 60 ppmv at 3.0% O_2, dry basis);

(2) from stationary, gas-fired, reciprocating internal combustion engines:

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

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

(3) from stationary, dual-fuel, reciprocating internal combustion engines, 5.83 g/hp-hr;

(4) from stationary, diesel, reciprocating internal combustion engines:

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

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

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

(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;

(ii) 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;

(iii) 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;

(iv) 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;

(v) 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

(vi) 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;

(5) from stationary gas turbines (including duct burners), 0.15 lb/MMBtu; and

(6) as an alternative to the emission specifications in paragraphs (1) - (5) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu heat input. For units placed into service on or before 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).

(d) The maximum rated capacity used to determine the applicability of the emission specifications in subsection (c) of this section must be:

(1) the greater of the following:

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

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

(2) 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, for which 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.

(e) 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 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.

(f) Changes after December 31, 2000, to a unit subject to an emission specification in subsection (c) of this section (ESAD unit) that result in increased NO_x emissions from a unit not subject to an emission specification in subsection (c) of this section (non-ESAD unit), such as redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator or a flare, is only allowed if:

(1) the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS that meets the requirements of §117.2035(c) of this title, or through stack testing that meets the requirements of §117.2035(e) of this title; and

(2) either of the following conditions is met:

(A) for sources that are subject to Chapter 101, Subchapter H, Division 3 of this title, a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit is made as specified in §101.354 of this title (relating to Allowance Deductions); or

(B) for sources that are not subject to Chapter 101, Subchapter H, Division 3 of this title, emission credits equal to the increase in NO_x emissions at the non-ESAD unit are obtained and used in accordance with §117.9800 of this title (relating to Use of Emission Credits for Compliance).

(g) 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.

(h) The availability under subsection (c)(6) 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 (c)(6) of this section than would otherwise apply to the unit.

(i) No person shall allow the discharge into the atmosphere from any unit subject to NO_x emission specifications in subsection (c) of this section, emissions in excess of the following, except as provided in §117.2025 of this title (relating to Alternative Case Specific Specifications):

(1) carbon monoxide (CO), 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines):

(A) on a rolling 24-hour averaging period, for units equipped with CEMS or PEMS for CO; and

(B) on a one-hour average, for units not equipped with CEMS or PEMS for CO; and

(2) for units that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions of 10 ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts) and gas-fired lean-burn engines; and 3.0% O_2, dry, for all other units, based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

§117.2025. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the carbon monoxide (CO) or ammonia specifications of §117.2010(i) of this title (relating to Emission Specifications), the executive director may approve emission specifications different from the CO or ammonia specifications in §117.2010(i) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) shall determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.2010 of this title; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through system-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply.

§117.2030. Operating Requirements.

(a) The owner or operator shall operate any unit subject to §117.2010 of this title (relating to Emission Specifications) in compliance with those requirements.

(b) All units subject to §117.2010 of this title must be operated so as to minimize nitrogen oxides (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 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 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.

(4) 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.

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

(c) 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.

§117.2035. Monitoring and Testing Requirements.

(a) Totalizing fuel flow meters.

(1) The owner or operator of each unit subject to §117.2010 of this title (relating to Emission Specifications) and subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), or of each unit claimed exempt under §117.2003(b) of this title (relating to Exemptions) shall install, calibrate, maintain, and operate totalizing fuel flow meters with an accuracy of ±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 ±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.

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

(A) Units operating with a nitrogen oxides (NO_x) and diluent continuous emissions monitoring system (CEMS) under subsection (c) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (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 (c) 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.

(D) Units of the same category of equipment subject to Chapter 101, Subchapter H, Division 3 of this title may share a single totalizing fuel flow meter provided:

(i) the owner or operator performs a stack test in accordance with subsection (e) of this section for each unit sharing the totalizing fuel flow meter; and

(ii) the testing results from the unit with the highest emission rate (in pounds per million British thermal units or grams per horsepower-hour) are used for reporting purposes in §101.359 of this title (relating to Reporting) for all units sharing the totalizing fuel flow meter.

(E) The owner or operator of a unit or units claimed exempt under §117.2003(b) of this title, located at an independent school district may demonstrate compliance with the exemption by the following:

(i) in addition to the records required by §117.2045(a)(1) of this title (relating to Recordkeeping and Reporting Requirements), maintain the following monthly records in either electronic or written format. These 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;

(I) total fuel usage for the entire site;

(II) the estimated hours of operation for each unit;

(III) the estimated average operating rate (e.g., a percentage of maximum rated capacity) for each unit; and

(IV) the estimated fuel usage for each unit;, and

(ii) within 60 days of written request by the executive director, submit for review and approval all methods, engineering calculations, and process information used to estimate the hours of operation, operating rates, and fuel usage for each unit.

(F) The owner or operator of units claimed exempt under §117.2003(b) of this title may share a single totalizing fuel flow meter to demonstrate compliance with the exemption, provided that:

(i) all affected units at the site qualify for the exemption under §117.2003(b) of this title; and

(ii) the total fuel usage for all units at the site is less than:

(I) the annual fuel usage limitation in §117.2003(b)(1) of this title; or

(II) the annual fuel usage limitation in §117.2003(b)(2) of this title when all affected units at the site are equal to or greater than 5.0 million British thermal units per hour.

(b) Oxygen (O_2) monitors. If the owner or operator installs an O_2 monitor, the criteria in §117.8100(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources) should be considered the appropriate guidance for the location and calibration of the monitor.

(c) NO_x monitors. If the owner or operator installs a CEMS or predictive emissions monitoring system (PEMS), it must meet the requirements of §117.8100(a) or (b) of this title. If a PEMS is used, 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 Minor Sources).

(d) Monitor installation schedule. Installation of monitors must be performed in accordance with the schedule specified in §117.9200 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Minor Sources).

(e) Testing requirements. The owner or operator of any unit subject to §117.2010 of this title shall comply with the following testing requirements.

(1) Each unit must be tested for NO_x, carbon monoxide (CO), and O_2 emissions.

(2) One of the ammonia monitoring procedures specified in §117.8130 of this title (relating to Ammonia Monitoring) must be used to demonstrate compliance with the ammonia emission specification of §117.2010(i)(2) of this title for units that inject urea or ammonia into the exhaust stream for NO_x control.

(3) For units not equipped with CEMS or PEMS, all testing must be conducted according to §117.8000 of this title (relating to Stack Testing Requirements). In lieu of the test methods specified in §117.8000 of this title, the owner or operator may use American Society for Testing and Materials (ASTM) D6522-00 to perform the NO_x, CO, and O_2 testing required by this subsection on natural gas-fired reciprocating engines, combustion turbines, boilers, and process heaters. If the owner or operator elects to use ASTM D6522-00 for the testing requirements, the report must contain the information specified in §117.8010 of this title (relating to Compliance Stack Test Reports).

(4) Test results must be reported in the units of the applicable emission specifications and averaging periods. If compliance testing is based on 40 CFR Part 60, Appendix A reference methods, the report must contain the information specified in §117.8010 of this title.

(5) For units equipped with CEMS or PEMS, the CEMS or PEMS must be installed and operational before testing under this subsection. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's

written requirements or recommendations for installation, operation, and calibration of the device.

(6) Initial compliance with §117.2010 of this title for units operating with CEMS or PEMS must be demonstrated after monitor certification testing using the NO_x CEMS or PEMS.

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

(A) Retesting as specified in paragraphs (1) - (4) of this subsection is required within 60 days after any modification that could reasonably be expected to increase the NO_x emission rate.

(B) Retesting as specified in paragraphs (1) - (4) of this subsection may be conducted at the discretion of the owner or operator after any modification that could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation, and fuel-lean and conventional (fuel-rich) reburn.

(C) The NO_x emission rate determined by the retesting must establish a new emission factor to be used 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.

(8) Testing must be performed in accordance with the schedule specified in §117.9200 of this title.

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

(f) Emission allowances.

(1) For sources that are subject to Chapter 101, Subchapter H, Division 3 of this title, the NO_x testing and monitoring data of subsections (a) - (e) 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 calculating actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(2) The emission factor in subsection (e)(7) of this section or paragraph (1) 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.

(g) Run time meters. The owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.2003(a)(2)(E), (H), or (I) 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.

§117.2045. Recordkeeping and Reporting Requirements.

(a) Recordkeeping. The owner or operator of a unit subject to §117.2010 of this title (relating to Emission Specifications) or claimed exempt under §117.2003(b) of this title (relating to Exemptions) 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) records of annual fuel usage;

(2) for each unit using a continuous emission monitoring system (CEMS) or predictive emission monitoring system (PEMS) in accordance with §117.2035(c) of this title (relating to Monitoring and Testing Requirements), monitoring records of:

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

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

(i) pounds per million British thermal units heat input; and

(ii) pounds or tons per day;

(3) for each stationary internal combustion engine subject to §117.2010 of this title, records of:

(A) emissions measurements required by §117.2030(b)(5) of this title (relating to Operating Requirements); 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) records of carbon monoxide measurements specified in §117.2030(b)(5) of this title;

(5) 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; and

(6) records of the results of performance testing, including the testing conducted in accordance with §117.2035(e) of this title.

(b) Records for exempt engines. Written records of the number of hours of operation for each day's operation must be made for each engine claimed exempt under §117.2003(a)(2)(E), (H), or (I) of this title or §117.2030(b)(5) of this title. In addition, for each engine claimed exempt under §117.2003(a)(2)(E) 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. The records must be maintained for at least five years and must be made available upon request to representatives of the executive director, the United States Environmental Protection Agency, or any local air pollution control agency having jurisdiction.

(c) Records of operation for testing and maintenance. The owner or operator of each stationary diesel or dual-fuel engine shall maintain the following records for at least five years and make them available upon request by authorized representatives of the executive director, the United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction:

(1) date(s) of operation;

(2) start and end times of operation;

(3) identification of the engine; and

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

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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DIVISION 2. DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MINOR SOURCES

30 TAC §§117.2100, 117.2103, 117.2110, 117.2125, 117.2130, 117.2135, 117.2145

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.2100. Applicability.

This division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources) applies in the Dallas-Fort Worth eight-hour ozone nonattainment area to the following equipment at any stationary source of nitrogen oxides (NO_x) that is not a major source of NO_x:

(1) boilers and process heaters;

(2) stationary, reciprocating internal combustion engines; and

(3) stationary gas turbines, including duct burners.

§117.2103. Exemptions.

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

(1) boilers and process heaters with a maximum rated capacity of 2.0 million British thermal units per hour (MMBtu/hr) or less;

(2) the following stationary engines:

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

(B) engines used in research and testing;

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

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

(E) engines operated 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 June 1, 2007, is ineligible for this exemption. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations (CFR) §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account;

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

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

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

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

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

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

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

(ii) meet the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 (October 23, 1998) and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (December 16, 1975),

respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

(3) stationary gas turbines rated at less than 1.0 megawatt with initial start of operation on or before June 1, 2007.

(b) The following are exempt from the requirements of this division, except for the requirements of §117.2135(a) and (d) and §117.2145(a)(1) of this title:

(1) any boiler or process heater with a maximum rated capacity greater than 2.0 MMBtu/hr and less than 5.0 MMBtu/hr that has an annual heat input less than or equal to 1.8 (10^9) British thermal units (Btu) per calendar year, or has an average heat input less than or equal to 1.5 (10^8) Btu per month for the months of May through October; and

(2) any boiler or process heater with a maximum rated capacity equal to or greater than 5.0 MMBtu/hr that has an annual heat input less than or equal to 9.0 (10^9) Btu per calendar year, or has an average heat input less than or equal to 7.5 (10^8) Btu per month for the months of May through October.

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

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

(1) from boilers and process heaters:

(A) gas-fired, 0.036 pounds per million British thermal units (lb/MMBtu) heat input (or alternatively, 30 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry basis); and

(B) liquid-fired, 0.072 lb/MMBtu heat input (or alternatively, 60 ppmv at 3.0% O_2, dry basis);

(2) from stationary, gas-fired, reciprocating internal combustion engines:

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

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

(3) from stationary, dual-fuel, reciprocating internal combustion engines, 5.83 g/hp-hr;

(4) from stationary, diesel, reciprocating internal combustion engines:

(A) placed into service before June 1, 2007, that have not been modified, reconstructed, or relocated on or after June 1, 2007, 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 paragraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account; and

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

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

(I) on or after June 1, 2007, but before January 1, 2008, 5.0 g/hp-hr; and

(II) on or after January 1, 2008, 3.3 g/hp-hr;

(ii) with a horsepower rating of 100 hp or greater, but less than or equal to 750 hp, that are installed, modified, reconstructed, or relocated on or after June 1, 2007, 2.8 g/hp-hr; and

(iii) with a horsepower rating of 750 hp or greater that are installed, modified, reconstructed, or relocated on or after June 1, 2007, 4.5 g/hp-hr;

(5) from stationary gas turbines (including duct burners), 0.15 lb/MMBtu; and

(6) as an alternative to the emission specifications in paragraphs (1) - (5) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu heat input. For units placed into service on or before December 31, 2000, the annual capacity factor as of December 31, 2000, must be used to determine eligibility for the alternative emission specification of this paragraph. For units placed into service after December 31, 2000, a 12-month rolling average must be used to determine the annual capacity factor.

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

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

(A) a rolling 30-day average period, in the units of the applicable standard;

(B) a block one-hour average, in the units of the applicable standard, or alternatively;

(C) a block one-hour average, in pounds per hour, for boilers and process heaters, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in lb/MMBtu; or

(2) if the unit is not operated with a NO_x CEMS or PEMS under §117.2135(c) of this title, a block one-hour average, in the units of the applicable standard.

(c) The maximum rated capacity used to determine the applicability of the emission specifications in subsection (a) of this section must be the greater of the following:

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

(2) the maximum rated capacity after December 31, 2000.

(d) 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 stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, must be classified as a stationary gas-fired engine for the purposes of this chapter.

(e) Changes after December 31, 2000, to a unit subject to an emission specification in subsection (a) of this section (ESAD unit) that result in increased NO_x emissions from a unit not subject to an emission specification in 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 or a flare, is only allowed if:

(1) the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS that meets the requirements

of §117.2135(c) of this title, or through stack testing that meets the requirements of §117.2135(f) of this title; and

(2) emission credits equal to the increase in NO_x emissions at the non-ESAD unit are obtained and used in accordance with §117.9800 of this title (relating to Use of Emission Credits for Compliance).

(f) 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 becomes a major source at any time after December 31, 2000, is from that time forward always classified as a major source for purposes of this chapter.

(g) The availability under subsection (a)(6) 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)(6) of this section than would otherwise apply to the unit.

(h) No person shall allow the discharge into the atmosphere from any unit subject to NO_x emission specifications in subsection (a) of this section, emissions in excess of the following, except as provided in §117.2125 of this title (relating to Alternative Case Specific Specifications):

(1) carbon monoxide (CO), 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines):

(A) on a rolling 24-hour averaging period, for units equipped with CEMS or PEMS for CO; and

(B) on a one-hour average, for units not equipped with CEMS or PEMS for CO; and

(2) for units that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions of 10 ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts) and gas-fired lean-burn engines; and 3.0% O_2, dry, for all other units, based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(i) An owner or operator may use emission reduction credits as specified in §117.9800 of this title to comply with the NO_x emission specifications of this section.

§117.2125. Alternative Case Specific Specifications.

(a) Where an owner or operator can demonstrate that an affected unit cannot attain the carbon monoxide (CO) or ammonia specifications of §117.2110(h) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration), the executive director may approve emission specifications different from the CO or ammonia specifications in §117.2110(h) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) shall determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.2110 of this title; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through system-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply.

§117.2130. Operating Requirements.

(a) The owner or operator shall operate any unit subject to the emission specifications of §117.2110 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) in compliance with those specifications.

(b) All units subject to §117.2110 of this title must be operated so as to minimize nitrogen oxides (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 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 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.

(4) 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 specifications.

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

(c) 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.

§117.2135. Monitoring, Notification, and Testing Requirements.

(a) Totalizing fuel flow meters.

(1) The owner or operator of any unit claimed exempt under §117.2103(b) of this title (relating to Exemptions) shall install, calibrate, maintain, and operate totalizing fuel flow meters with an accuracy of ±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. 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.

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

(A) The owner or operator of a unit or units claimed exempt under §117.2103(b) of this title, located at an independent school district may demonstrate compliance with the exemption by the following:

(i) in addition to the records required by §117.2145(a)(1) of this title (relating to Recordkeeping and Reporting Requirements), maintain the following monthly records in either electronic or written format. These 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;

(I) total fuel usage for the entire site;

(II) the estimated hours of operation for each unit;

(III) the estimated average operating rate (e.g., a percentage of maximum rated capacity) for each unit; and

(IV) the estimated fuel usage for each unit; and

(ii) within 60 days of written request by the executive director, submit for review and approval all methods, engineering calculations, and process information used to estimate the hours of operation, operating rates, and fuel usage for each unit.

(B) The owner or operator of units claimed exempt under §117.2103(b) of this title may share a single totalizing fuel flow meter to demonstrate compliance with the exemption, provided that:

(i) all affected units at the site qualify for the exemption under §117.2103(b) of this title; and

(ii) the total fuel usage for all units at the site is less than:

(I) the annual or monthly fuel usage limitation, as applicable, in §117.2103(b)(1) of this title; or

(II) the annual or monthly fuel usage limitation, as applicable, in §117.2103(b)(2) of this title when all affected units at the site are equal to or greater than 5.0 million British thermal units per hour.

(b) Oxygen (O_2) monitors. If the owner or operator installs an O_2 monitor, the criteria in §117.8100(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources) should be considered the appropriate guidance for the location and calibration of the monitor.

(c) Nitrogen oxides (NO_x) monitors. If the owner or operator installs a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS), the CEMS or PEMS must meet the requirements of §117.8100(a) or (b) of this title. If a PEMS is used, the PEMS must predict the pollution emissions in the units of the applicable emission limitations of this division.

(d) Monitor installation schedule. Installation of monitors must be performed in accordance with the schedule specified in §117.9210 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources).

(e) Testing requirements. The owner or operator of any unit subject to §117.2110 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) shall comply with the following testing requirements.

(1) Each unit must be tested for NO_x, carbon monoxide (CO), and O_2 emissions.

(2) One of the ammonia monitoring procedures specified in §117.8130 of this title (relating to Ammonia Monitoring) must be used to demonstrate compliance with the ammonia emission specification of §117.2110(h)(2) of this title for units that inject urea or ammonia into the exhaust stream for NO_x control.

(3) For units not equipped with CEMS or PEMS, all testing must be conducted according to §117.8000 of this title (relating to Stack Testing Requirements). In lieu of the test methods specified in §117.8000 of this title, the owner or operator may use American Society for Testing and Materials (ASTM) D6522-00 to perform the NO_x, CO, and O_2 testing required by this subsection on natural gas-fired reciprocating engines, combustion turbines, boilers, and process heaters. If the owner or operator elects to use ASTM D6522-00 for the testing requirements, the report must contain the information specified in §117.8010 of this title (relating to Compliance Stack Test Reports).

(4) Test results must be reported in the units of the applicable emission specifications and averaging periods. If compliance testing is based on 40 Code of Federal Regulations Part 60, Appendix A reference methods, the report must contain the information specified in §117.8010 of this title.

(5) For units equipped with CEMS or PEMS, the CEMS or PEMS must be installed and operational before testing under this subsection. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(6) Initial compliance with the emission specifications of §117.2110 of this title for units operating with CEMS or PEMS must be demonstrated after monitor certification testing using the NO_x CEMS or PEMS.

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

(A) Retesting as specified in paragraphs (1) - (4) of this subsection is required within 60 days after any modification that could reasonably be expected to increase the NO_x emission rate.

(B) Retesting as specified in paragraphs (1) - (4) of this subsection may be conducted at the discretion of the owner or operator after any modification that could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation, and fuel-lean and conventional (fuel-rich) reburn.

(C) Stationary, reciprocating internal combustion engines not equipped with CEMS or PEMS must be periodically tested for NO_x and CO emissions as specified in §117.8140(a) of this title (relating to Emission Monitoring for Engines).

(8) Testing must be performed in accordance with the schedule specified in §117.9210 of this title.

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

(10) The owner or operator of an affected unit in the Dallas-Fort Worth eight-hour ozone nonattainment area must submit written notification of any CEMS or PEMS relative accuracy test audit (RATA) or testing required under this section to the appropriate regional office and any local air pollution control agency having jurisdiction at least 15 days in advance of the date of RATA or testing.

(f) Run time meters. The owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.2103(a)(2)(E), (H), or (I) of this title shall record the operating time with a non-resettable elapsed run time meter.

§117.2145. Recordkeeping and Reporting Requirements.

(a) Recordkeeping. The owner or operator of a unit subject to §117.2110 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) or claimed exempt under §117.2103(b) of this title (relating to Exemptions) 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 units claimed exempt under §117.2103(b) of this title, records of annual or monthly fuel usage, as applicable;

(2) for each unit using a continuous emission monitoring system (CEMS) or predictive emission monitoring system (PEMS) in accordance with §117.2135(c) of this title (relating to Monitoring, Notification, and Testing Requirements) monitoring records of:

(A) hourly emissions for units complying with an emission specification enforced on a block one-hour average; and

(B) daily emissions for units complying with an emission specification enforced on a rolling 30-day average. Emissions must be recorded in units of:

(i) pounds per million British thermal units (MMBtu) heat input; and

(ii) pounds or tons per day;

(3) for each stationary internal combustion engine subject to §117.2110 of this title, records of:

(A) emissions measurements required by §117.2130(b)(5) of this title (relating to Operating Requirements); 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) records of carbon monoxide (CO) measurements specified in §117.2130(b)(5) of this title;

(5) 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; and

(6) records of the results of performance testing, including the testing conducted in accordance with §117.2135(e) of this title.

(b) Records for exempt engines. Written records of the number of hours of operation for each day's operation must be made for each engine claimed exempt under §117.2103(a)(2)(E), (H), or (I) of this title or §117.2130(b)(5) of this title. In addition, for each engine claimed exempt under §117.2103(a)(2)(E) 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. The records must be maintained for at least five years and must be made available upon request to representatives of the executive director, the United States Environmental Protection Agency, or any local air pollution control agency having jurisdiction.

(c) Records of operation for testing and maintenance. The owner or operator of each stationary diesel or dual-fuel engine shall maintain the following records for at least five years and make them available upon request by authorized representatives of the executive director, the United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction:

(1) date(s) of operation;

(2) start and end times of operation;

(3) identification of the engine; and

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

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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SUBCHAPTER E. MULTI-REGION COMBUSTION CONTROL
DIVISION 1. UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS

30 TAC §§117.3000, 117.3003, 117.3005, 117.3010, 117.3020, 117.3025, 117.3035, 117.3040, 117.3045, 117.3054, 117.3056

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.3000. Applicability.

(a) The provisions of this division (relating to Utility Electric Generation in East and Central Texas) apply to each utility electric power boiler and stationary gas turbine (including duct burners used in turbine exhaust ducts) that:

(1) generates electric energy for compensation;

(2) is owned or operated by an electric cooperative, independent power producer, municipality, river authority, or public utility, or any of its successors;

(3) was placed into service before December 31, 1995; and

(4) is located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, or Wharton County.

(b) The provisions of §117.3005 of this title (relating to Gas-Fired Steam Generation) also apply in Palo Pinto County.

§117.3003. Exemptions.

The provisions of this division (relating to Utility Electric Generation in East and Central Texas), except as specified in §117.3040 and §117.3045 of this title (relating to Continuous Demonstration of Compliance; and Notification, Recordkeeping, and Reporting Requirements), do not apply to:

(1) utility electric power boilers or stationary gas turbines if the annual heat input does not exceed 2.2 (10^{11}) British thermal units per year, averaged over the three most recent calendar years;

(2) stationary gas turbines and auxiliary steam boilers that are:

(A) used solely to power other units during startups; or

(B) demonstrated to operate no more than an average of 10% of the hours of the year, averaged over the three most recent calendar years, and no more than 20% of the hours in a single calendar year; and

(3) each unit that generates electric energy primarily for internal use but that, averaged over the three most recent calendar years, sold less than one-third of its potential electrical output capacity to a utility power distribution system.

§117.3005. Gas-Fired Steam Generation.

(a) Subsections (b), (c), and (d) of this section (emission specifications adopted by the Texas Air Control Board in 1972) apply in Fannin, Hood, and Palo Pinto Counties. This section no longer applies in Fannin and Hood Counties after the applicable final compliance date specified in §117.9300 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(b) No person shall allow emissions of nitrogen oxides (NO_x), calculated as nitrogen dioxide (NO_2), from any "opposed-fired" steam generating unit of more than 600,000 pounds per hour (lb/hr) maximum continuous steam capacity to exceed 0.7 pound per million British thermal units (lb/MMBtu) heat input, maximum two-hour average, at maximum steam capacity. An "opposed-fired" steam generating unit is defined as a unit having burners installed on two opposite vertical firebox surfaces.

(c) No person shall allow emissions of NO_x, calculated as NO_2, from any "front-fired" steam generating unit of more than 600,000 lb/hr maximum continuous steam capacity to exceed 0.5 lb/MMBtu heat input, maximum two-hour average, at maximum steam capacity. A "front-fired" steam generating unit is defined as a unit having all burners installed in a geometric array on one vertical firebox surface.

(d) No person shall allow emissions of NO_x, calculated as NO_2, from any "tangential-fired" steam generating unit of more than 600,000 lb/hr maximum continuous steam capacity to exceed 0.25 lb/MMBtu heat input, maximum two-hour average, at maximum steam capacity. A "tangential-fired" steam generating unit is defined as a unit having burners installed on all corners of the unit at various elevations.

(e) Existing gas-fired steam generating units of more than 600,000 lb/hr, but less than 1,100,000 lb/hr, maximum continuous steam capacity are exempt from the provisions of this section, provided the total steam generated from the unit during any one calendar year does not exceed 30% of the product of the maximum continuous steam capacity of the unit times the number of hours in a year. Written records of the amount of steam generated for each day's operation must be made on a daily basis and maintained for at least three years from the date of each entry. Such records must be made available upon request to representatives of the executive director, United States Environmental Protection Agency, or any local air pollution control agency having jurisdiction.

§117.3010. Emission Specifications.

In accordance with the compliance schedule in §117.9300 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas), the owner or operator of each utility electric power boiler or stationary gas turbine (including duct burners used in turbine exhaust ducts) shall:

(1) ensure that emissions of nitrogen oxides (NO_x) do not exceed the following rates, in pounds per million British thermal units heat input on an annual (calendar year) average:

(A) electric power boilers:

(i) gas-fired, 0.14; and

(ii) coal-fired, 0.165;

(B) stationary gas turbines (including duct burners used in turbine exhaust ducts):

(i) subject to Texas Utilities Code (TUC), §39.264 (except units designated in accordance with TUC, §39.264(i)), 0.14;

(ii) not subject to TUC, §39.264, 0.15 (or alternatively, 42 parts per million by volume (ppmv) NO_x, adjusted to 15% oxygen (O_2), dry basis); and

(iii) units designated in accordance with TUC, §39.264(i), 0.15 (or alternatively, 42 ppmv NO_x, adjusted to 15% O_2, dry basis); and

(2) ensure that for units that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions do not exceed 10 ppmv at 3.0% O_2, dry, for boilers and 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts) from any unit subject to the NO_x emission specifications in paragraph (1) of this section, based on:

(A) a block one-hour averaging period for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

§117.3020. System Cap.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission specifications of §117.3010 of this title (relating to Emission Specifications) by achieving equivalent NO_x emission reductions obtained by compliance with a system cap emission limitation in accordance with the requirements of this section.

(b) Each unit within an electric power generating system, as defined in §117.10 of this title (relating to Definitions), that would otherwise be subject to the NO_x emission specifications of §117.3010 of this title must be included in the system cap.

(c) The annual average emission cap must be calculated using the following equation.
Figure: 30 TAC §117.3020(c)

(d) The NO_x emissions monitoring required by §117.3040 of this title (relating to Continuous Demonstration of Compliance) for each unit in the system cap must be used to demonstrate continuous compliance with the system cap.

(e) For each operating unit, 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) Part 75, use the missing data procedures specified in 40 CFR Part 75, Subpart D (Missing Data Substitution Procedures); or

(B) 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);

(2) use Appendix E monitoring in accordance with §117.3040(e) of this title;

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

(A) use the methods specified in 40 CFR Part 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 emission rate as measured by the testing conducted in accordance with §117.3035(d) of this title (relating to Initial Demonstration of Compliance).

(f) The owner or operator of any unit subject to a system cap shall maintain daily records indicating the NO_x emissions and fuel usage from each unit and summations of total NO_x emissions and fuel usage for all units under the system cap on a daily basis. Records must also be retained in accordance with §117.3045 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(g) The owner or operator of any unit subject to a system cap shall submit annual reports for the monitoring systems in accordance with §117.3045 of this title. The owner or operator shall also report any exceedance of the system cap emission limit in the annual report and shall include 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.

(h) The owner or operator of any unit subject to a system cap shall demonstrate initial compliance with the system cap in accordance with the schedule specified in §117.9300 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(i) A unit that is permanently retired or decommissioned and rendered inoperable may be included in the system cap emission limit, provided that the permanent shutdown occurred on or after January 1, 1999. 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 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 NO_x emission rate measured by the NO_x monitor, if operating properly. If the NO_x monitor is not operating properly, the substitute data procedures identified in subsection (e) of this section must be used. If neither the NO_x 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 United States Environmental Protection Agency that actual emissions were less than maximum emissions during such periods.

(l) An owner or operator of a source of NO_x in any of the east and central Texas attainment counties listed in §117.3000(4) of this title (relating to Applicability) who is participating in the system cap under this section (relating to System Cap) may exceed their system cap provided that the owner or operator is complying with the requirements of Chapter 101, Subchapter H, Division 1, 4, or 5 of this title (relating to Emission Credit Banking and Trading; Discrete Emission Credit Banking and Trading; and System Cap Trading).

§117.3025. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the ammonia specification of §117.3010(2) of this title (relating to Emission Specifications), the executive director may approve emission specifications different from the ammonia specification in §117.3010(2) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) shall determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the

application of controls to meet the nitrogen oxides emission specifications of §117.3010 of this title; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through system-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply.

§117.3035. Initial Demonstration of Compliance.

(a) The owner or operator of all units that are subject to the emission specifications of §117.3010 of this title (relating to Emission Specifications) shall test the units as follows.

(1) The units must be tested for nitrogen oxides (NO_x), carbon monoxide, and oxygen emissions.

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

(3) Testing must be performed in accordance with the schedule specified in §117.9300 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(b) The tests required by subsection (a) of this section must be used for determination of initial compliance with the emission specifications of this division (relating to Utility Electric Generation in East and Central Texas). Test results must be reported in the units of the applicable emission specifications and averaging periods. If compliance testing is based on 40 Code of Federal Regulations, Part 60, Appendix A reference methods, the report must contain the information specified in §117.8010 of this title (relating to Compliance Stack Test Reports).

(c) Continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) required by §117.3040 of this title (relating to Continuous Demonstration of Compliance) must be installed and operational before testing under subsection (a) of this section. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(d) Initial compliance with the emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.3040 of this title must be demonstrated after monitor certification testing using the NO_x CEMS or PEMS as follows. To comply with the NO_x emission specification in pounds per million British thermal units on an annual average, NO_x emissions from a unit are monitored for each unit operating day in a calendar year, and the annual average emission rate is used to determine compliance with the NO_x emission specification. The annual average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during a calendar year.

§117.3040. Continuous Demonstration of Compliance.

(a) Nitrogen oxides (NO_x) monitoring. The owner or operator of each unit subject to the emission specifications of this division (relating to Utility Electric Generation in East and Central Texas) shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS), predictive emissions monitoring system (PEMS), or other system specified in this section to measure NO_x on an individual basis.

(b) Carbon monoxide (CO) monitoring. If the owner or operator chooses to monitor CO exhaust emissions from a unit subject to the emission specifications of this division, the methods specified in §117.8120 of this title (relating to Carbon Monoxide (CO) Monitoring) should be considered appropriate guidance for determining CO emissions.

(c) Ammonia monitoring. For units that inject urea or ammonia into the exhaust stream for NO_x control, one of the ammonia monitoring procedures specified in §117.8130 of this title (relating to Ammonia Monitoring) must be used to demonstrate compliance with the ammonia emission specification of §117.3010(2) of this title (relating to Emission Specifications).

(d) CEMS requirements.

(1) Any CEMS required by this section must be installed, calibrated, maintained, and operated in accordance with 40 Code of Federal Regulations (CFR) Part 75 or Part 60, as applicable.

(2) One CEMS may be shared among units, provided:

(A) the exhaust stream of each unit is analyzed separately; and

(B) the CEMS meets the applicable certification requirements of paragraph (1) of this subsection for each exhaust stream.

(3) As an alternative to paragraph (2) of this subsection, for units that are included in a system cap under §117.3020 of this title (relating to System Cap):

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

(B) one CEMS may be shared among units, provided:

(i) the exhaust stream of each stack is analyzed separately; and

(ii) the CEMS meets the certification requirements of paragraph (1) of this subsection for each stack while the CEMS is operating in the time-shared mode; and

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

(e) Acid rain peaking units. The owner or operator of each peaking unit as defined in 40 CFR §72.2, may:

(1) monitor operating parameters for each unit in accordance with 40 CFR Part 75, Appendix E, §1.1 or §1.2 and calculate NO_x emission rates based on those procedures; or

(2) use CEMS or PEMS in accordance with this section to monitor NO_x emission rates.

(f) PEMS requirements. The owner or operator of any PEMS used to meet a pollutant monitoring requirement of this section shall comply with the following. The required PEMS and fuel flow meters must be used to demonstrate continuous compliance with the emission specifications of §117.3010 of this title.

(1) The PEMS must predict the pollutant emissions in the units of the applicable emission specifications of this division.

(2) The PEMS must meet the requirements of §117.8110(b) of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources).

(g) Gas turbine monitoring. The owner or operator of each stationary gas turbine subject to the emission specifications of §117.3010 of this title, instead of monitoring emissions in accordance with the monitoring requirements of 40 CFR Part 75, may comply with the following monitoring requirements:

(1) for stationary gas turbines rated less than 30 megawatt (MW) or peaking gas turbines (as defined in §117.10 of this title (relating to Definitions)) that use steam or water injection to comply with the emission specification of §117.3010(1)(B) of this title:

(A) install, calibrate, maintain, and operate a CEMS or PEMS in compliance with this section; or

(B) for units that are not included in a system cap under §117.3020 of this title, install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. The system must be accurate to within ±5.0%. The steam-to-fuel or water-to-fuel ratio monitoring data must be used for demonstrating continuous compliance with the emission specification of §117.3010(1)(B) of this title; and

(2) for gas turbines not subject to paragraph (1) of this subsection, install, calibrate, maintain, and operate a CEMS or PEMS in compliance with this section.

(h) Totalizing fuel flow meters. The owner or operator of units listed in this subsection shall install, calibrate, maintain, and operate totalizing fuel flow meters 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 units are:

(1) any unit subject to the emission specifications of this division;

(2) any stationary gas turbine with an MW rating greater than or equal to 1.0 MW operated more than an average of 10% of the hours of the year, averaged over the three most recent calendar years, or more than 20% of the hours in a single calendar year; and

(3) any unit claimed exempt from the emission specifications of this division using the exemption of §117.3003(1) of this title (relating to Exemptions).

(i) Run time meters. The owner or operator of any stationary gas turbine using the exemption of §117.3003(2) of this title shall record the operating time with an elapsed run time meter approved by the executive director.

(j) Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the exemptions of §117.3003 of this title, shall notify the executive director within seven days if the applicable limit is exceeded.

(1) If the limit is exceeded, the exemption from the emission specifications of §117.3010 of this title 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.

(k) Data used for compliance. After the initial demonstration of compliance required by §117.3035 of this title (relating to Initial Demonstration of Compliance) the methods required in this section must be used to determine compliance with the emission specifications of this division. Compliance with the emission specifications may also be determined at the discretion of the executive director using any commission compliance method.

(l) Enforcement of NO_x limits. No unit subject to §117.3010 of this title may be operated at an emission rate higher than that allowed by the emission specifications of §117.3010 of this title.

§117.3045. 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, 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 fuel burned; gross and net energy production in megawatt-hours (MW-hr); and the date, time, and duration of the event.

(b) Notification. The owner or operator of a unit subject to the emission specifications of this division (relating to Utility Electric Generation in East and Central Texas) shall submit notification to the executive director as follows:

(1) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.3035 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 systems (CEMS) or predictive emissions monitoring systems (PEMS) performance evaluation conducted under §117.3040 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 executive director and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.3035 of this title or any CEMS or PEMS performance evaluation conducted under §117.3040 of this title:

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

(2) not later than the appropriate compliance schedule specified in §117.9300 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(d) Annual reports. The owner or operator of a unit required to install a CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system under §117.3040 of this title shall report in writing to the executive director on an annual basis any exceedance of the applicable emission specifications in this division and the monitoring system performance. All reports must be postmarked or received by January 31 following the end of each calendar year. 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. For stationary gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.3040 of this title, excess emissions are computed as each one-hour period that the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial demonstration of compliance test required by §117.3035 of this title;

(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 steam-to-fuel or water-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 or steam-to-fuel or water-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) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain records of the data specified in this subsection. Records must be kept for a period of at least five years and made available for inspection by the executive director, United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction upon request. Operating records for each unit must be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or for units claimed exempt from the emission specifications based on low annual capacity factor, monthly. Records must include:

(1) emission rates in units of the applicable standards;

(2) gross energy production in MW-hr (not applicable to auxiliary steam boilers);

(3) quantity and type of fuel burned;

(4) the injection rate of reactant chemicals (if applicable); and

(5) emission monitoring data in accordance with §117.3040 of this title, including:

(A) the date, time, and duration of any malfunction in the operation of the monitoring system, except for zero and span checks, if applicable, and a description of system repairs and adjustments undertaken during each period;

(B) the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, PEMS, or operating parameter monitoring systems; and

(C) actual emissions or operating parameter measurements, as applicable;

(6) the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.3035 of this title; and

(7) records of hours of operation.

§117.3054. Final Control Plan Procedures.

(a) The owner or operator of units listed in §117.3000 of this title (relating to Applicability) shall submit a final control report to show compliance with the requirements of §117.3010 of this title (relating to Emission Specifications). The report must include:

(1) the section under which nitrogen oxides (NO_x) compliance is being established for the units within the electric generating system, either:

(A) §117.3010 of this title; or

(B) §117.3020 of this title (relating to System Cap);

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

(3) the emissions measured by testing required in §117.3035 of this title (relating to Initial Demonstration of Compliance);

(4) 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 §117.3035 of this title that is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any unit with a claimed exemption from the emission specifications of §117.3010 of this title.

(b) In addition to the requirements of subsection (a) of this section, the owner or operator of each source complying with §117.3020 of this title shall submit:

(1) the calculations used to calculate the annual average system cap allowable emission rate;

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

(A) the average annual heat input H_i specified in §117.3020(c) of this title;

(B) the method of monitoring emissions; and

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

(3) an explanation of the basis of the value of H_i.

(c) The report must be submitted by the applicable date specified for final control plans in §117.9300 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas). The plan must be updated with any emission compliance measurements submitted for units using a continuous emissions monitoring system or predictive emissions monitoring system and complying with the system cap annual average emission limit, according to the applicable schedule given in §117.9300 of this title.

§117.3056. 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 emission specifications and the final compliance dates of this division (relating to Utility Electric Generation in East and Central Texas). The revision of the final control plan is subject to the review and approval of the executive director.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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DIVISION 2. CEMENT KILNS

30 TAC §§117.3100, 117.3101, 117.3103, 117.3110, 117.3120, 117.3123, 117.3125, 117.3140, 117.3142, 117.3145

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.3100. Applicability.

This division (relating to Cement Kilns) applies to each portland cement kiln in Bexar, Comal, Ellis, Hays, and McLennan Counties.

§117.3101. Cement Kiln Definitions.

Unless specifically defined in the Texas Clean Air Act (TCAA) or in the rules of the commission, the terms used by the commission have the meanings commonly used in the field of air pollution control. In addition to the terms that are defined by the TCAA, the following terms, when used in this division (relating to Cement Kilns), have the following meanings, unless the context clearly indicates otherwise. Additional definitions for terms used in this division are found in §§3.2, 101.1, and 117.10 of this title (relating to Definitions).

(1) Clinker--The product of a portland cement kiln from which finished cement is manufactured by milling and grinding.

(2) Indirect-firing system--A system that reduces the amount of primary air used in a cement kiln by:

(A) separating the powdered fuel from the air stream that carries the fuel from the drying/milling equipment;

(B) storing the fuel briefly; and

(C) using an independent, significantly smaller stream of hot primary air to blow the fuel to the burner.

(3) Long dry kiln--A kiln that employs no preheating of the dry feed. The inlet feed to the kiln is dry.

(4) Long wet kiln--A kiln that employs no preheating of the dry feed. The inlet feed to the kiln is a slurry.

(5) Low-NO_x burner--Either of the following:

(A) for long wet kilns, combustion equipment designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion; or

(B) a type of cement kiln burner that results in decreasing nitrogen oxides emissions and that has an indirect-firing system and a series of channels or orifices that:

(i) allow for the adjustment of the volume, velocity, pressure, and direction of the air carrying the fuel (known as primary air) and the combustion air (known as secondary air) into the kiln; and

(ii) impart high momentum and turbulence to the fuel stream to facilitate mixing of the fuel and secondary air.

(6) Low-NO_x precalciner--A process in which a portion of the fuel is injected near the raw material feed end of a preheater or precalciner kiln, resulting in a reducing atmosphere in the preheater or precalciner.

(7) Mid-kiln firing--Secondary combustion in long dry or long wet kilns by injecting solid fuel at (or to) an intermediate point in the kiln using a specially-designed feed injection mechanism for the purpose of decreasing nitrogen oxides emissions through:

(A) burning part of the fuel at a lower temperature; and

(B) reducing conditions at the solid fuel injection point that may destroy some of the nitrogen oxides formed upstream in the kiln burning zone.

(8) Portland cement--A hydraulic cement produced by pulverizing clinker consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an interground addition.

(9) Portland cement kiln--A system, including any solid, gaseous, or liquid fuel combustion equipment, used to calcine and fuse raw materials, including limestone and clay, to produce portland cement clinker.

(10) Precalciner kiln--A kiln where the feed to the kiln system is preheated in cyclone chambers and utilizes a second burner to calcine material in a separate vessel attached to the preheater before the final fusion in a kiln that forms clinker.

(11) Preheater kiln--A kiln where the feed to the kiln system is preheated in cyclone chambers before the final fusion in a kiln that forms clinker.

(12) Secondary combustion--A system that employs a second combustion point in addition to the primary flame. This definition includes mid-kiln firing in long dry and long wet kilns, and also additional combustion at the raw material feed end of the kiln in preheater-precalciner kilns.

§117.3103. Exemptions.

(a) Portland cement kilns exempted from the provisions of this division (relating to Cement Kilns), include any portland cement kiln placed into service on or after December 31, 1999, except as specified in §§117.3110, 117.3120, and 117.3123 of this title (relating to Emission Specifications; Source Cap; and Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements).

(b) Any account in Ellis County with no portland cement kilns in operation prior to January 1, 2001, is exempt from §117.3123 of this title.

(c) Section 117.3110 and §117.3120 of this title no longer apply to portland cement kilns that are subject to §117.3123 of this title after the compliance date specified in §117.9320(c) of this title (relating to Compliance Schedule for Cement Kilns).

§117.3110. Emission Specifications.

(a) In accordance with the compliance schedule in §117.9320 of this title (relating to Compliance Schedule for Cement Kilns), the owner or operator of each portland cement kiln shall ensure that nitrogen oxides (NO_x) emissions do not exceed the following rates on a 30-day rolling average. For the purposes of this section, the 30-day rolling average is calculated as the total of all the hourly emissions data (in pounds) that fuel was combusted in a cement kiln in the preceding 30 consecutive days, divided by the total number of tons of clinker produced in that kiln during the same 30-day period:

(1) for each long wet kiln:

(A) in Bexar, Comal, Hays, and McLennan Counties, 6.0 pounds per ton (lb/ton) of clinker produced; and

(B) in Ellis County, 4.0 lb/ton of clinker produced;

(2) for each long dry kiln, 5.1 lb/ton of clinker produced;

(3) for each preheater kiln, 3.8 lb/ton of clinker produced; and

(4) for each preheater-precalciner or precalciner kiln, 2.8 lb/ton of clinker produced.

(b) If there are multiple cement kilns at the same account, the owner or operator may choose to comply with the emission specifications of subsection (a) of this section on the basis of a weighted average for the cement kilns at the account that are subject to the same specification. Each owner or operator choosing this option shall submit written notification of this choice to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction before the appropriate compliance date in §117.9320 of this title.

(c) Each long wet or long dry kiln for which the following controls are installed and operated during kiln operation is not required to meet the NO_x emission specifications of subsection (a) of this section, provided that each owner or operator choosing this option submits written notification of this choice to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction before the appropriate compliance date in §117.9320 of this title:

(1) a low-NO_x burner and either:

(A) mid-kiln firing; or

(B) some other form of secondary combustion achieving equivalent levels of NO_x reductions; or alternatively;

(2) other additions or changes to the kiln system achieving at least a 30% reduction in NO_x emissions, provided the additions or changes are approved by the executive director with concurrence from the United States Environmental Protection Agency.

(d) Each preheater or precalciner kiln for which either a low-NO_x burner or a low-NO_x precalciner is installed and operated during kiln operation is not required to meet the NO_x emission specifications of subsection (a) of this section. Each owner or operator choosing this option shall submit written notification of this choice to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction before the appropriate compliance date in §117.9320 of this title.

(e) An owner or operator may use §117.9800 of this title (relating to Use of Emission Credits for Compliance) to meet the NO_x emission control requirements of this section, in whole or in part.

§117.3120. Source Cap.

(a) As an alternative to complying with the requirements of §117.3110 of this title (relating to Emission Specifications) in Bexar, Comal, Ellis, Hays, and McLennan Counties, an owner or operator may reduce total nitrogen oxides (NO_x) emissions (in pounds per day (ppd)) from all cement kilns at the account (including any cement kilns placed into service on or after December 31, 1999) to at least 30% less than the total NO_x emissions (in ppd) from all cement kilns in the account's 1996 emissions inventory (EI), on a 90-day rolling average basis. For the purposes of this section, the 90-day rolling average is calculated as the total of all the hourly emissions data for the preceding 90 days. For the calendar year that includes the appropriate compliance date in §117.9320 of this title (relating to Compliance Schedule for Cement Kilns), only hourly emissions data on or after that compliance date is included, such that the first 90-day period ends 90 days after the appropriate compliance date in §117.9320 of this title. A 90-day rolling average emission cap must be calculated using the following equation. Figure: 30 TAC §117.3120(a)

(b) To qualify for the source cap option available under this section, the owner or operator shall submit an initial control plan to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction that demonstrates that the overall reduction of NO_x emissions from all cement kilns at the account will be at least 30% from the 1996 baseline EI on a 90-day rolling average basis. The plan must be submitted no later than December 31 of the year preceding the appropriate compliance date in §117.9320 of this title. Each control plan must be approved by the executive director before the owner or operator may use the source cap available under this section for compliance. At a minimum, the control plan must include the emission point number (EPN), facility identification number (FIN), and 1996 baseline EI NO_x emissions (in ppd) from each cement kiln at the account; a description of the control measures that have been or will be implemented at each cement kiln; and an explanation of the recordkeeping procedure and calculations that will be used to demonstrate compliance.

(c) Beginning on March 31 of the year following the appropriate compliance date in §117.9320 of this title, the owner or operator shall submit an annual report no later than March 31 of each year to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction that demonstrates that the overall reduction of NO_x emissions from all cement kilns at the account is at least 30% from the 1996 baseline EI on a 90-day rolling average basis. At a minimum, the report must include the EPN, FIN, and each

90-day rolling average NO_x emissions (in ppd) during the preceding calendar year for the cement kilns at the account.

(d) All representations in control plans and annual reports become enforceable conditions. The owner or operator shall not vary from such representations if the variation will cause a change in the identity of the specific cement kilns subject to this section or the method of control of emissions unless the owner or operator submits a revised control plan to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction no later than 30 days after the change. All control plans and reports must demonstrate that the total NO_x emissions (in ppd) from all cement kilns at the account (including any cement kilns placed into service on or after December 31, 1999) are being reduced to at least 30% less than the total NO_x emissions (in ppd) from all cement kilns in the account's 1996 EI on a 90-day rolling average basis.

(e) The NO_x emissions monitoring required by §117.3140 of this title (relating to Continuous Demonstration of Compliance) for each cement kiln in the source cap must be used to demonstrate continuous compliance with the source cap.

(f) An owner or operator may use §117.9800 of this title (relating to Use of Emission Credits for Compliance) to meet the NO_x emission control requirements of this section, in whole or in part.

§117.3123. Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements.

(a) In accordance with the compliance schedule in §117.9320(c) of this title (relating to Compliance Schedule for Cement Kilns), the owner or operator of any portland cement kiln located in Ellis County shall not allow the total nitrogen oxides (NO_x) emissions from all cement kilns located at the account to exceed the source cap limitation determined according to subsection (b) of this section.

(b) The NO_x source cap for an account subject to this section must be calculated according to the following equation.
Figure: 30 TAC §117.3123(b)

(c) The monitoring required by §117.3142 of this title (relating to Emission Testing and Monitoring for Eight-Hour Attainment Demonstration) for each cement kiln subject to this section must be used to demonstrate continuous compliance with the source cap requirements of this section. Compliance with the source cap must be demonstrated on a rolling 30-day average basis, calculated according to §117.3142 of this title.

(d) For any portland cement kiln not operational prior to calendar year 2001 and that is located at an account subject to this section, the following requirements apply.

(1) The cement kiln is subject to the source cap of this section but must not be included in the source cap calculation in subsection (b) of this section.

(2) The requirements of §117.3142 of this title and §117.3145 of this title (relating to Notification, Recordkeeping, and Reporting Requirements) apply.

(3) The NO_x emissions from the kiln must be included in the calculation of rolling 30-day average NO_x emissions according to §117.3142 of this title for compliance with the source cap in subsection (b) of this section.

(e) The owner or operator of each portland cement kiln located in Ellis County shall submit a control plan to the Office of Compliance and Enforcement, the appropriate regional office, and the Chief Engineer's Office, for compliance with the source cap in subsection (b) of this section. The plan must be submitted according to the compliance schedule in §117.9320(c) of this title.

(1) At a minimum, the control plan must include:

(A) the emission point number for each kiln at the account;

(B) the facility identification number for each kiln at the account;

(C) the source cap for the account calculated according to the equation in subsection (b) of this section; and

(D) a description of the control measures that have been or will be implemented for each cement kiln for compliance with the source cap.

(2) A revised control plan may be submitted by the owner or operator, along with any required permit applications. Such a plan must adhere to the requirements of this division (relating to Cement Kilns).

(f) For any kiln that injects urea or ammonia for NO_x control, the owner or operator shall not allow ammonia emissions in excess of 10 parts per million by volume at 7.0% oxygen, dry basis, on a rolling 24-hour average basis.

(g) An owner or operator may use §117.9800 of this title (relating to Use of Emission Credits for Compliance) to meet the NO_x emission control requirements of this section, in whole or in part.

§117.3125. Alternative Case Specific Specifications.

(a) Where an owner or operator can demonstrate that an affected portland cement kiln cannot attain the ammonia emission specification in §117.3123(f) of this title (relating to Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements), the executive director may approve an emission specification different from §117.3123(f) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual portland cement kiln;

(2) shall determine that such specifications are the result of the lowest ammonia emission specification the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission source cap of §117.3123 of this title; and

(3) in determining whether to approve alternative ammonia emission specifications, may take into consideration the ability of the plant where the unit is located to meet emission specifications through plant-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Cement Kilns).

§117.3140. Continuous Demonstration of Compliance.

(a) Nitrogen oxides (NO_x) monitors. In accordance with the compliance schedule in §117.9320 of this title (relating to Compliance Schedule for Cement Kilns), the owner or operator shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) to monitor kiln exhaust NO_x.

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

(1) The CEMS must meet the requirements of 40 Code of Federal Regulations Part 60 as follows:

(A) §60.13;

(B) Appendix B, Performance Specification 2, for NO_x; and

(C) audits in accordance with Section 5.1 of Appendix F, quality assurance procedures, except that a cylinder gas audit or relative accuracy audit may be performed in lieu of the annual relative accuracy test audit (RATA) required in Section 5.1.1.

(2) One CEMS may be shared among kilns, provided:

(A) the exhaust stream of each kiln is analyzed separately; and

(B) the CEMS meets the certification requirements of paragraph (1) of this subsection for each exhaust stream.

(3) The CEMS is subject to the approval of the executive director.

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

(1) The PEMS must predict the NO_x emissions in the units of the applicable emission limitations of this division (relating to Cement Kilns).

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

§117.3142. Emission Testing and Monitoring for Eight-Hour Attainment Demonstration.

(a) An owner or operator of any portland cement kiln that is subject to the source cap of §117.3123 of this title (relating to Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements) shall comply with the following monitoring requirements.

(1) The nitrogen oxides (NO_x) monitoring requirements of §117.3140 of this title (relating to Continuous Demonstration of Compliance) apply. The following requirements also apply.

(A) For a single portland cement kiln with multiple exhaust stacks, each individual stack must be analyzed separately.

(B) One continuous emission monitoring system (CEMS) may be shared among portland cement kilns or among multiple exhaust stacks on a single portland cement kiln, provided:

(i) the exhaust stream of each stack is analyzed and reported separately; and

(ii) the CEMS meets the certification requirements of §117.3140(b) of this title for each exhaust stream while the CEMS is operating in the time-shared mode.

(C) All bypass stacks must be monitored continuously, in order to quantify emissions directed through the bypass stack. 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 record automatically the date, time, and duration of each event when the bypass stack is open.

(2) Stack exhaust flow rate must be monitored with a flow meter using the monitoring specifications of 40 Code of Federal Regulations (CFR) Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

(3) For portland cement kilns that inject ammonia or urea for NO_x control, ammonia emissions must be monitored according to one of the methods specified in §117.8130(1), (2), or (4) of this title (relating to Ammonia Monitoring) to demonstrate compliance with the ammonia emission specification in §117.3123(f) of this title.

(4) Installation of monitors must be performed in accordance with the schedule specified in §117.9320(c) of this title (relating to Compliance Schedule for Cement Kilns).

(b) The owner or operator of a portland cement kiln subject to the source cap requirements of §117.3123 of this title shall calculate NO_x emissions for determining compliance with the source cap as follows.

(1) Hourly NO_x emissions. Hourly NO_x emissions for each kiln must be calculated according to the following equation.
Figure: 30 TAC §117.3142(b)(1)

(2) Daily NO_x emissions. The daily total NO_x emission for each kiln must be calculated as the sum of the 24 hourly NO_x emissions for each calendar day, reported in tons per day, and must be calculated according to the following equation.
Figure: 30 TAC §117.3142(b)(2)

(3) Rolling 30-day average. The rolling 30-day average NO_x emissions for the account must be calculated according to the following equation.
Figure: 30 TAC §117.3142(b)(3)

§117.3145. Notification, Recordkeeping, and Reporting Requirements.

(a) Notification. The owner or operator of each portland cement kiln shall submit verbal notification to the executive director of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) performance evaluation conducted under §117.3140 or §117.3142 of this title (relating to Continuous Demonstration of Compliance; and Emission Testing and Monitoring for Eight-Hour Attainment Demonstration) at least 15 days before such date followed by written notification within 15 days after testing is completed.

(b) Reporting of test results. The owner or operator of each portland cement kiln shall furnish the executive director and any local air pollution control agency having jurisdiction a copy of any CEMS or PEMS relative accuracy test audit conducted under §117.3140 or §117.3142 of this title:

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

(2) not later than the appropriate compliance date in §117.9320 of this title (relating to Compliance Schedule for Cement Kilns).

(c) Recordkeeping. The owner or operator of a portland cement kiln subject to the requirements of this division (relating to Cement Kilns) 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, United States Environmental

Protection Agency, or local air pollution control agencies having jurisdiction. The records must include:

(1) for each kiln subject to §117.3110 or §117.3120 of this title (relating to Emission Specifications; and Source Cap), monitoring records of:

(A) daily and rolling 30-day average (and, for each kiln subject to the source cap in §117.3120 of this title, rolling 90-day average) nitrogen oxides (NO_x) emissions (in pounds);

(B) daily and rolling 30-day average (and, for each kiln subject to the source cap in §117.3120 of this title, rolling 90-day average) production of clinker (in United States short tons); and

(C) average NO_x emission rate (in pounds per ton (lb/ton) of clinker produced) on the basis of a rolling 30-day average (and, for each kiln subject to the source cap in §117.3120 of this title, a rolling 90-day average);

(2) records of the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS and PEMS;

(3) records of the results of any stack testing conducted; and

(4) for each kiln subject to the source cap in §117.3123 of this title (relating to Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements) and emission testing and monitoring requirements in §117.3142 of this title:

(A) records of the control plan required under §117.3123 of this title;

(B) hourly records of the average NO_x concentration in parts per million by volume, dry basis, at 7% oxygen (O_2);

(C) hourly records of the NO_x emissions in pounds per hour;

(D) daily records of the NO_x emissions in tons per day;

(E) daily records of the NO_x emissions in tons per day expressed as a rolling 30-day average;

(F) hourly records of the average exhaust gas flow rate in dry standard cubic feet per minute, corrected to 7% O_2; and

(G) records of ammonia monitoring required under §117.3142(a)(3) of this title.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
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DIVISION 3. WATER HEATERS, SMALL BOILERS, AND PROCESS HEATERS

30 TAC §§117.3200, 117.3201, 117.3203, 117.3205, 117.3210, 117.3215

STATUTORY AUTHORITY

The new sections are proposed under Texas Water Code, §5.102, concerning General Powers, §5.103, concerning Rules, and §5.105, concerning General Policy, that authorize the commission to adopt rules necessary to carry out its powers and duties under the Texas Water Code. In addition, the sections are proposed 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. The new sections are proposed under federal mandates contained in 42 United States Code, §§7410 *et. seq.,* that require states to adopt pollution control measures in order to reach specific air quality standards in particular areas of the state. In addition, the new sections are proposed to implement the legislative mandate under House Bill (HB) 965, 79th Legislature, 2005, which adds Texas Health and Safety Code, §382.0275, concerning Commission Action Relating to Residential Water Heaters, which requires certain actions of the commission regarding residential water heaters.

The proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, and 382.0275.

§117.3200. Applicability.

This division (relating to Water Heaters, Small Boilers, and Process Heaters) applies to manufacturers, distributors, retailers, and installers of natural gas-fired water heaters, boilers, and process heaters with a maximum rated capacity of 2.0 million British thermal units per hour or less.

§117.3201. Definitions.

Unless specifically defined in Texas Health and Safety Code, Chapter 382 (also known as the Texas Clean Air Act) or in the rules of the commission, the terms used by the commission have the meanings commonly used in the field of air pollution control. In addition to the terms that are defined by Texas Health and Safety Code, Chapter 382, the following terms, when used in this division (relating to Water Heaters, Small Boilers, and Process Heaters), have the following meanings, unless the context clearly indicates otherwise. Additional definitions for terms used in this division are found in §§3.2, 101.1, and 117.10 of this title (relating to Definitions).

(1) Heat output--The product H_o obtained when a Type 0, 1, or 2 unit is tested according to Section 9.3 of the South Coast Air Quality Management District Protocol: Nitrogen Oxides Emissions Compliance Testing for Natural Gas-Fired Water Heaters and Small Boilers (January 1998).

(2) Type 0 unit--Any water heater, boiler, or process heater with a maximum rated capacity of no more than 75,000 British thermal units per hour.

(3) Type 1 unit--Any water heater, boiler, or process heater with a maximum rated capacity greater than 75,000, but no more than 400,000 British thermal units per hour.

(4) Type 2 unit--Any water heater, boiler, or process heater with a maximum rated capacity greater than 400,000 British thermal units per hour, but no more than 2.0 million British thermal units per hour.

(5) Water heater--A closed vessel in which water is heated by combustion of gaseous fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 pounds per square inch gauge, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 degrees Fahrenheit.

§117.3203. Exemptions.

This division (relating to Water Heaters, Small Boilers, and Process Heaters) does not apply to:

(1) units using a fuel other than natural gas;

(2) units used in recreational vehicles;

(3) Type 0 units, or Type 1 or 2 units at single-family residences, used exclusively to heat swimming pools and hot tubs;

(4) units manufactured in Texas for shipment and use outside of Texas; and

(5) units that do not comply with the nitrogen oxides specifications in §117.3205 of this title (relating to Emission Specifications) that are sold, supplied, or offered for sale in Texas, provided that the manufacturer or distributor can demonstrate that the units are intended for shipment and use outside of Texas, and that the manufacturer or distributor has taken reasonable, prudent precautions to assure that the units are not distributed for sale in Texas. This paragraph does not apply to units that are sold, supplied, or offered for sale by any person to retail outlets in Texas.

§117.3205. Emission Specifications.

(a) Natural gas-fired boilers and process heaters sold, distributed, installed, or offered for sale within the State of Texas must meet the following specifications for nitrogen oxides (NO_x).

(1) Type 0 units manufactured on or after July 1, 2002, but no later than December 31, 2004, must not exceed:

(A) 40 nanograms per joule (ng/J) of heat output; or

(B) 55 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry.

(2) Type 0 units manufactured on or after January 1, 2005, must not exceed:

(A) 10 ng/J of heat output; or

(B) 15 ppmv at 3.0% O_2, dry.

(3) Type 1 units manufactured on or after July 1, 2002, must not exceed:

(A) 40 ng/J of heat output; or

(B) 55 ppmv at 3.0% O_2, dry.

(4) Type 2 units manufactured on or after July 1, 2002, must not exceed:

(A) 30 ppmv at 3.0% O_2, dry; or

(B) 0.037 pounds per million British thermal units (lb/MMBtu) of heat input.

(b) Natural gas-fired water heaters sold, distributed, installed, or offered for sale within the State of Texas must meet the following specifications for NO_x.

(1) Type 0 units manufactured on or after July 1, 2002, must not exceed:

(A) 40 ng/J of heat output; or

(B) 55 ppmv at 3.0% O_2, dry.

(2) Type 1 units manufactured on or after July 1, 2002, must not exceed:

(A) 40 ng/J of heat output; or

(B) 55 ppmv at 3.0% O_2, dry.

(3) Type 2 units manufactured on or after July 1, 2002, must not exceed:

(A) 30 ppmv at 3.0% O_2, dry; or

(B) 0.037 lb/MMBtu of heat input.

§117.3210. Certification Requirements.

(a) The manufacturer shall demonstrate that each model of Type 0, 1, and 2 unit subject to the requirements of §117.3205 of this title (relating to Emission Specifications) has been tested in accordance with Test Method 7 (40 Code of Federal Regulations Part 60, Appendix A), including 7A-E, and the South Coast Air Quality Management District (SCAQMD) Protocol: Nitrogen Oxides Emissions Compliance Testing for Natural Gas-Fired Water Heaters and Small Boilers (January 1998).

(b) The manufacturer may submit to the executive director an approved Bay Area Air Quality Management District or SCAQMD certification in lieu of conducting duplicative certification tests.

§117.3215. Notification and Labeling Requirements.

(a) Each manufacturer shall submit to the executive director a statement certifying that Type 0, 1, and 2 units subject to the requirements of §117.3205 of this title (relating to Emission Specifications) are in compliance with §117.3205 of this title. The statement must be signed and dated and attest to the accuracy of all information. The statement must include the manufacturer's brand name, model number, and the input rating as it appears on the rating plate. The manufacturer shall inform their wholesaler and/or retailer of the certification requirement of this subsection.

(b) The manufacturer shall display the model number and date of manufacture of each Type 0, 1, and 2 unit complying with §117.3205 of this title on the shipping carton and rating plate of each Type 0, 1, and 2 unit.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
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DIVISION 4. EAST TEXAS COMBUSTION

30 TAC §§117.3300, 117.3303, 117.3310, 117.3325, 117.3330, 117.3335, 117.3345

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.3300. Applicability.

This division (relating to East Texas Combustion) applies to stationary, gas-fired reciprocating internal combustion engines at any stationary source of nitrogen oxides in the following affected counties: Anderson, Bosque, Brazos, Burleson, Camp, Cass, Cherokee, Cooke, Freestone, Franklin, Grayson, Gregg, Grimes, Harrison, Henderson, Hill, Hood, Hopkins, Hunt, Lee, Leon, Limestone, Madison, Marion, Morris, Nacogdoches, Navarro, Panola, Rains, Robertson, Rusk, Shelby, Smith, Somervell, Titus, Upshur, Van Zandt, Wise, and Wood Counties.

§117.3303. Exemptions.

The following stationary engines are exempt from this division (relating to East Texas Combustion), except as specified in §117.3345(b) of this title (relating to Recordkeeping and Reporting Requirements):

(1) engines with a maximum rated horsepower (hp) capacity of less than 50 hp;

(2) engines used in research and testing;

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

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

(5) engines operated exclusively in emergency situations, except that operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average;

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

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

(8) diesel engines; and

(9) dual-fuel engines.

§117.3310. Emission Specifications for Eight-Hour Attainment Demonstration.

(a) The owner or operator of any stationary, gas-fired reciprocating internal combustion engine subject to this division (relating to East Texas Combustion) shall not allow the discharge into the atmosphere emissions of nitrogen oxides (NO_x) in excess of the following emission specifications:

(1) gas-fired rich-burn engines with a maximum rated capacity less than 500 horsepower (hp), 1.00 grams per horsepower-hour (g/hp-hr);

(2) gas-fired rich-burn engines with a maximum rated capacity equal to or greater than 500 hp:

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

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

(3) gas-fired lean-burn engines:

(A) 2.00 g/hp-hr for any engine placed into service before June 1, 2007, that has not been modified, reconstructed, or relocated on or after June 1, 2007. 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 §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

(B) 1.50 g/hp-hr for any engine installed, modified, reconstructed, or relocated on or after June 1, 2007.

(b) The averaging time for determining compliance with the emission specifications in subsection (a) of this section must be a block one-hour average, in the units of the applicable standard.

(c) The maximum rated capacity used to determine the applicability of the emission specifications of subsection (a) of this section or the exemption status of an engine under §117.3303(1) of this title (relating to Exemptions) must be the greater of the following:

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

(2) the maximum rated capacity after December 31, 2000.

(d) An engine's classification is determined by the most specific classification applicable to the unit as of December 31, 2000. For example, an engine 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, must be classified as a stationary gas-fired engine for the purposes of this chapter.

(e) The owner or operator of any engine subject to the NO_x emission specifications of subsection (a) of this section, shall not allow the discharge into the atmosphere emissions in excess of the following, except as provided in §117.3325 of this title (relating to Alternative Case Specific Specifications):

(1) carbon monoxide (CO) emissions of 400 parts per million by volume (ppmv), at 3.0% oxygen (O_2), dry basis, or alternatively, 3.0 g/hp-hr, based on:

(A) a rolling 24-hour averaging period, for engines equipped with continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

(B) a one-hour average, for engines not equipped with CEMS or PEMS for CO; and

(2) for units that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions of 10 ppmv at 15% O_2, dry, for gas-fired lean-burn engines, and 10 ppmv at 3.0% O_2, dry, for all other engines, based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(f) An owner or operator may use emission reduction credits as specified in §117.9800 of this title (relating to Use of Emission Credits for Compliance) to comply with the NO_x emission specifications of this section.

§117.3325. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected engine cannot attain the carbon monoxide (CO) or ammonia specifications of §117.3310(e) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration), the executive director may approve emission specifications different from the CO or ammonia specifications in §117.3310(e) of this title for that engine. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual engine;

(2) shall determine that such specifications are the result of the lowest emission limitation the engine is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.3310 of this title; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant where the engine is located to meet emission specifications through system-wide averaging at maximum capacity.

(b) Any owner or operator affected by the executive director's decision to deny an alternative case specific emission specification may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply.

§117.3330. Operating Requirements.

(a) The owner or operator shall operate any stationary, reciprocating combustion engine subject to §117.3310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) in compliance with the emission specifications of §117.3310 of this title.

(b) Each stationary, reciprocating combustion engine subject to §117.3310 of this title must be operated so as to minimize nitrogen oxides (NO_x) emissions, consistent with the emission control techniques selected, over the engine's operating or load range during normal operations. Such operational requirements include the following.

(1) Each engine 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.

(2) Each engine controlled with nonselective catalytic reduction must be equipped with an automatic air-fuel ratio (AFR) controller that operates on exhaust oxygen or carbon monoxide control basis and maintains the AFR in the range required to meet the engine's applicable emission specifications.

(3) Each engine must be checked for proper operation according to §117.8140(b) of this title (relating to Emission Monitoring for Engines).

§117.3335. Monitoring, Notification, and Testing Requirements.

(a) Oxygen (O_2) monitors. If the owner or operator installs a continuous emissions monitoring system (CEMS) to monitor O_2, 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).

(b) Nitrogen oxides (NO_x) monitors. If the owner or operator installs a CEMS or predictive emissions monitoring system (PEMS) to monitor NO_x, the CEMS or PEMS must meet the requirements of §117.8100(a) or (b) of this title, as applicable.

(c) Monitor installation schedule. If the owner or operator elects to installs CEMS or PEMS to monitor NO_x or O_2 as provided in subsections (a) and (b) of this section, installation and certification of monitoring systems must be performed in accordance with the schedule specified in §117.9340 of this title (relating to Compliance Schedule for East Texas Combustion).

(d) Testing requirements. The owner or operator of any stationary, reciprocating combustion engine subject to §117.3310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) shall comply with the following testing requirements.

(1) Each engine must be tested for NO_x, carbon monoxide (CO), and O_2 emissions.

(2) Each engine that injects urea or ammonia into the exhaust stream for NO_x control must be tested for ammonia emissions.

(3) For engines not equipped with CEMS or PEMS, all testing must be conducted according to §117.8000 of this title (relating to Stack Testing Requirements). In lieu of the test methods specified in §117.8000 of this title, the owner or operator may use American Society for Testing and Materials (ASTM) D6522-00 to perform the NO_x, CO, and O_2 testing required by this subsection on natural gas-fired reciprocating internal combustion engines. If the owner or operator elects to use ASTM D6522-00 for the testing requirements, the report must contain the information specified in §117.8010 of this title (relating to Compliance Stack Test Reports).

(4) Test results must be reported in the units of the applicable emission specifications and averaging periods.

(5) For engines equipped with CEMS or PEMS, the CEMS or PEMS must be installed and operational before conducting testing under this subsection. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(6) For engines operating with CEMS or PEMS, initial compliance with the emission specifications of §117.3310 of this title may be demonstrated by using the CEMS or PEMS, after monitor certification testing, in lieu of the methods specified in §117.3335(d)(3) of this title (relating to Monitoring, Notification, and Testing Requirements).

(7) For engines not operating with CEMS or PEMS, periodic testing for NO_x and CO emissions must be conducted according to §117.8140(a) of this title (relating to Emission Monitoring for Engines).

(A) Retesting as specified in paragraphs (1) - (4) of this subsection is required within 60 days after any modification that could reasonably be expected to increase the NO_x emission rate.

(B) Retesting as specified in paragraphs (1) - (4) of this subsection may be conducted at the discretion of the owner or operator after any modification that could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls or low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation, and fuel-lean and conventional (fuel-rich) reburn.

(8) Testing must be performed in accordance with the schedule specified in §117.9340 of this title.

(e) Ammonia monitoring. Each stationary, reciprocating combustion engine that injects urea or ammonia into the exhaust stream for NO_x control must be monitored according to one of the ammonia monitoring procedures specified in §117.8130 of this title (relating to Ammonia Monitoring).

(f) Notification. The owner or operator of an affected stationary, reciprocating combustion engine must submit written notification of any CEMS or PEMS relative accuracy test audit (RATA) or testing required under this section, except for testing related to ammonia monitoring specified in subsection (e) of this section, to the appropriate regional office and any local air pollution control agency having jurisdiction at least 15 days in advance of the date of RATA or testing.

§117.3345. Recordkeeping and Reporting Requirements.

(a) Recordkeeping. The owner or operator of a stationary, reciprocating combustion engine subject to §117.3310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) 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 engine using a continuous emissions monitoring system (CEMS) or predictive emissions monitoring systems (PEMS) in accordance with §117.3335(a) or (b) of this title (relating to Monitoring, Notification, and Testing Requirements), monitoring records of hourly emissions for engines complying with an emission specification enforced on a block one-hour average;

(2) for each engine subject to §117.3310 of this title, records of:

(A) emissions measurements required by §117.3330(b)(3) of this title (relating to Operating Requirements); and

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

(3) records of carbon monoxide measurements required by §117.3330(b)(3) of this title;

(4) 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;

(5) records of the results of performance testing, including the testing conducted in accordance with §117.3335(d) of this title; and

(6) records of the ammonia monitoring required by §117.3335(e) of this title, if applicable.

(b) Records for exempt engines. Written records of the number of hours of operation for each day's operation must be made for each engine claimed exempt under §117.3303(5) of this title (relating to Exemptions) or §117.3330(b)(3) of this title. In addition, for each engine claimed exempt under §117.3303(5) of this title, written records must be maintained that document the purpose of the engine operation, and if operation was for an emergency situation, identify the type of emergency situation and the start and end times and date(s) of the emergency situation. The records must be maintained for at least five years and must be made available upon request to representatives of the executive director, the United States Environmental Protection Agency, or any local air pollution control agency having jurisdiction.

(c) Reporting. Except for the ammonia monitoring requirements of §117.3335(e) of this title, the owner or operator of an affected stationary, reciprocating combustion engine shall furnish the appropriate regional office and the Office of Compliance and Enforcement reports of all testing and monitor certifications required under §117.3335 of this title. Reports must be submitted for review and approval within 60 days after completion of the testing and must contain the information specified in §117.8010 of this title (relating to Compliance Stack Test Reports).

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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SUBCHAPTER F. ACID MANUFACTURING
DIVISION 1. ADIPIC ACID MANUFACTURING

30 TAC §§117.4000, 117.4005, 117.4025, 117.4035, 117.4040, 117.4045, 117.4050

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.4000. Applicability.

The provisions of this division (relating to Adipic Acid Manufacturing) apply only in the Beaumont-Port Arthur and Houston-Galveston-Brazoria ozone nonattainment areas. These provisions apply to each adipic acid production unit that is the affected facility.

§117.4005. Emission Specifications.

No person may allow emissions of nitrogen oxides, calculated as nitrogen dioxide, from the absorber of any adipic acid production unit to exceed 2.5 pounds per ton of adipic acid produced, on a 24-hour rolling average.

§117.4025. Alternative Case Specific Specifications.

Where a person can demonstrate that an affected unit cannot attain the requirements of §117.4005 of this title (relating to Emission Specifications), as applicable, the executive director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117.4005 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.4005 of this title. Any owner or operator affected by the decision of the executive director may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Adipic Acid Manufacturing).

§117.4035. Initial Demonstration of Compliance.

(a) Compliance with the nitrogen oxides emission specifications in §117.4005 of this title (relating to Emission Specifications) must be determined by the performance testing procedures specified in 40 Code of Federal Regulations (CFR) Part 60, Appendix A, Method 7, or an equivalent method approved by the executive director. Method 7A, 7B, 7C, or 7D may be used in place of Method 7. If Method 7C or 7D is used, the sampling time must be at least one hour.

(b) Performance testing must be conducted in accordance with the procedures specified in 40 CFR §60.8.

(c) Any continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) required by §117.4040 of this title (relating to Continuous Demonstration of Compliance) must be installed and operational prior to conducting performance testing under subsections (a) and (b) of this section. Verification of operational status must, at a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system.

(d) Testing conducted before June 23, 1994, may be used to demonstrate compliance with the standard specified in §117.4005 of this title if the owner or operator of an affected facility demonstrates to the executive director that the prior performance testing at least meets the requirements of subsections (a) - (c) of this section. The executive director reserves the right to request performance testing or CEMS or PEMS performance evaluation at any time.

§117.4040. Continuous Demonstration of Compliance.

(a) The owner or operator of any facility subject to the provisions of this division (relating to Adipic Acid Manufacturing) shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring nitrogen oxides (NO_x) from the absorber.

(b) Any CEMS installed subject to subsection (a) of this section must meet all requirements of 40 Code of Federal Regulations (CFR) §60.13; 40 CFR Part 60, Appendix B, Performance Specification 2; and quality assurance procedures of 40 CFR Part 60, Appendix F, except that a cylinder gas audit may be performed in lieu of the annual relative accuracy test audit required in Section 5.1.1.

(c) As an alternative to CEMS, the owner or operator of units subject to continuous monitoring requirements under this division may, with the approval of the executive director, elect to install, calibrate, maintain, and operate a predictive emissions monitoring system (PEMS). The required PEMS must be used to measure NO_x emissions for each affected unit and must be used to demonstrate continuous compliance with the emission specifications of §117.4005 of this title (relating to Emission Specifications). Any PEMS must meet the requirements of §117.4045 and §117.8100(b) of this title (relating to Notification, Recordkeeping, and Reporting Requirements; and Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources).

(d) The owner or operator of an affected facility shall establish a conversion factor for the purpose of converting monitoring data into units of the NO_x emission standard (in pounds per ton of acid produced) as specified in 40 CFR §60.73(b). NO_x emissions data recorded by the CEMS or PEMS must be represented in terms of both parts per million by volume and pounds per ton of acid produced.

(e) After the initial demonstration of compliance required by §117.4035 of this title (relating to Initial Demonstration of Compliance), compliance with §117.4005 of this title must be determined by the methods required in this section. Compliance with the emission specifications may also be determined at the discretion of the executive director using any commission compliance method.

§117.4045. Notification, Recordkeeping, and Reporting Requirements.

(a) The owner or operator of an affected facility shall submit notification to the executive director, as follows:

(1) verbal notification of the date of any continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) performance evaluation conducted under §117.4040(b) 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; and

(2) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.4035 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.

(b) The owner or operator of an affected facility shall furnish the executive director and any local air pollution control agency having jurisdiction a copy of any CEMS or PEMS performance evaluation conducted under §117.4040 of this title, or any initial demonstration of compliance testing conducted under §117.4035 of this title, within 60 days after completion of such evaluation or testing. For purposes of demonstrating compliance with §117.9500 of this title (relating to Compliance Schedule for Nitric Acid and Adipic Acid Manufacturing Sources), such results must be submitted no later than 30 days before the final compliance date specified in §117.9500 of this title.

(c) The owner or operator of an affected facility shall report in writing to the executive director on a quarterly basis all periods of excess emissions, defined as any 24-hour period that the average nitrogen oxides emissions (arithmetic average of 24 contiguous one-hour periods) exceed the emission specification in §117.4005 of this title (relating to Emission Specifications) and the monitoring system performance. All reports must be postmarked or received by the 30th day following the end of each calendar quarter. 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 process operating time during the reporting period;

(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 CEMS or PEMS 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 operating time for the reporting period and the CEMS or PEMS downtime for the reporting period is less than 5.0% of the total 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 or PEMS 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.

(d) The owner or operator of an affected facility shall maintain written records of all continuous emissions monitoring and performance test results, hours of operation, and daily production rates. 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.

§117.4050. Control Plan Procedures.

Any person affected by this division (relating to Adipic Acid Manufacturing) shall submit a control plan to the executive director on the compliance status of all required emission controls and monitoring systems by April 1, 1994. The executive director shall approve the plan if it contains all the information specified in this section. Revisions to the control plan must be submitted to the executive director for approval. The control plan must provide a detailed description of the method to be followed to achieve compliance, specifying the anticipated dates that the following steps will be taken:

(1) dates that contracts for emission control and monitoring systems will be awarded or dates that orders will be issued for the purchase of component parts to accomplish emission control or process modification;

(2) date of initiation of on-site construction or installation of emission control equipment or process modification;

(3) date that on-site construction or installation of emission control equipment or process modification is to be completed; and

(4) date that final compliance is to be achieved.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
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DIVISION 2. NITRIC ACID MANUFACTURING--OZONE NONATTAINMENT AREAS

30 TAC §§117.4100, 117.4105, 117.4125, 117.4135, 117.4140, 117.4145, 117.4150

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.4100. Applicability.

The provisions of this division (relating to Nitric Acid Manufacturing--Ozone Nonattainment Areas) apply only in the Beaumont-Port Arthur and Houston-Galveston-Brazoria ozone nonattainment areas. These provisions apply to each nitric acid production unit that is the affected facility.

§117.4105. Emission Specifications.

No person may allow emissions of nitrogen oxides, calculated as nitrogen dioxide, from the absorber of any nitric acid production unit to exceed 2.0 pounds per ton of nitric acid produced, the production being expressed as 100% nitric acid, on a 24-hour rolling average.

§117.4125. Alternative Case Specific Specifications.

Where a person can demonstrate that an affected unit cannot attain the requirements of §117.4105 of this title (relating to Emission Specifications), as applicable, the executive director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117.4105 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.4105 of this title. Any owner or operator affected by the decision of the executive director may file a motion to overturn the executive director's decision. The requirements of §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the United States Environmental Protection Agency in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Nitric Acid Manufacturing--Ozone Nonattainment Areas).

§117.4135. Initial Demonstration of Compliance.

(a) Compliance with the nitrogen oxides emission specifications in §117.4105 of this title (relating to Emission Specifications) must be determined by the performance testing procedures specified in 40 Code of Federal Regulations (CFR) Part 60, Appendix A, Method 7, or an equivalent method approved by the executive director. Method 7A, 7B, 7C, or 7D may be used in place of Method 7. If Method 7C or 7D is used, the sampling time must be at least one hour.

(b) Performance testing must be conducted in accordance with the procedures specified in 40 CFR §60.8.

(c) Any continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) required by §117.4140 of this title (relating to Continuous Demonstration of Compliance) must be installed and operational prior to conducting performance testing under subsections (a) and (b) of this section. Verification of operational status must, at a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system.

(d) Testing conducted before June 23, 1994, may be used to demonstrate compliance with the standard specified in §117.4105 of this title if the owner or operator of an affected facility demonstrates to the executive director that the prior performance testing, at a minimum, meets the requirements of subsections (a) - (c) of this section. The executive director reserves the right to request performance testing or CEMS or PEMS performance evaluation at any time.

§117.4140. Continuous Demonstration of Compliance.

(a) The owner or operator of any facility subject to the provisions of this division (relating to Nitric Acid Manufacturing--Ozone Nonattainment Areas) shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring nitrogen oxides (NO_x) from the absorber.

(b) Any CEMS installed subject to subsection (a) of this section must meet all requirements of 40 Code of Federal Regulations (CFR) §60.13; 40 CFR Part 60, Appendix B, Performance Specification 2; and quality assurance procedures of 40 CFR Part 60, Appendix F, except that a cylinder gas audit may be performed in lieu of the annual relative accuracy test audit required in Section 5.1.1.

(c) As an alternative to CEMS, the owner or operator of units subject to continuous monitoring requirements under this division may, with the approval of the executive director, elect to install, calibrate, maintain, and operate a predictive emissions monitoring system (PEMS). The required PEMS must be used to measure NO_x emissions for each affected unit and must be used to demonstrate continuous compliance with the emission limitations of §117.4105 of this title (relating to Emission Specifications). Any PEMS must meet the requirements of §117.4145 and §117.8100(b) of this title (relating to Notification, Recordkeeping, and Reporting Requirements; and Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources).

(d) The owner or operator of an affected facility shall establish a conversion factor for the purpose of converting monitoring data into units of the NO_x emission standard (in pounds per ton of acid produced, expressed as 100% nitric acid) as specified in 40 CFR §60.73(b). NO_x emissions data recorded by the CEMS or PEMS must be represented in terms of both parts per million by volume and pounds per ton of acid produced, expressed as 100% nitric acid.

(e) After the initial demonstration of compliance required by §117.4135 of this title (relating to Initial Demonstration of Compliance), compliance with §117.4105 of this title must be determined by the methods required in this section. Compliance with the emission specifications may also be determined at the discretion of the executive director using any commission compliance method.

§117.4145. Notification, Recordkeeping, and Reporting Requirements.

(a) The owner or operator of an affected facility shall submit notification to the executive director, as follows:

(1) verbal notification of the date of any continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) performance evaluation conducted under §117.4140(b) 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; and

(2) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.4135 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.

(b) The owner or operator of an affected facility shall furnish the executive director and any local air pollution control agency having jurisdiction a copy of any CEMS or PEMS performance evaluation conducted under §117.4140 of this title, or any initial demonstration of compliance testing conducted under §117.4135 of this title, within 60 days after completion of such evaluation or testing. For purposes of demonstrating compliance with §117.9500 of this title (relating to Compliance Schedule for Nitric Acid and Adipic Acid Manufacturing Sources), such results must be submitted no later than 30 days before the final compliance date specified in §117.9500 of this title.

(c) The owner or operator of an affected facility shall report in writing to the executive director on a quarterly basis all periods of excess emissions, defined as any 24-hour period that the average nitrogen oxides emissions (arithmetic average of 24 contiguous one-hour periods), as measured by a CEMS or PEMS, exceed the emission specification in §117.4105 of this title (relating to Emission Specifications) and the monitoring system performance. All reports must be postmarked or received by the 30th day following the end of each calendar quarter. 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 process operating time during the reporting period;

(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 CEMS or PEMS 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 operating time for the reporting period and the CEMS or PEMS downtime for the reporting period is less than 5.0% of the total 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 or PEMS 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.

(d) The owner or operator of an affected facility shall maintain written records of all continuous emissions monitoring and performance test results, hours of operation, and daily production rates. 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 any local air pollution control agency having jurisdiction.

§117.4150. Control Plan Procedures.

Any person affected by this division (relating to Nitric Acid Manufacturing--Ozone Nonattainment Areas) shall submit a control plan to the executive director on the compliance status of all required emission controls and monitoring systems by April 1, 1994. The executive director shall approve the plan if it contains all the information specified in this section. Revisions to the control plan must be submitted to the executive director for approval. The control plan must provide a detailed description of the method to be followed to achieve compliance, specifying the anticipated dates that the following steps will be taken:

(1) dates that contracts for emission control and monitoring systems will be awarded or dates that orders will be issued for the purchase of component parts to accomplish emission control or process modification;

(2) date of initiation of on-site construction or installation of emission control equipment or process modification;

(3) date that on-site construction or installation of emission control equipment or process modification is to be completed; and

(4) date that final compliance is to be achieved.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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DIVISION 3. NITRIC ACID MANUFACTURING--GENERAL

30 TAC §§117.4200, 117.4205, 117.4210

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.4200. Applicability.

The emission specifications in §117.4205 of this title (relating to Emission Specifications) apply to all nitric acid production units in the state, with the exception that, for nitric acid production units located in applicable ozone nonattainment areas, the emission specifications of §117.4105 of this title (relating to Emission Specifications) apply after November 15, 1999.

§117.4205. Emission Specifications.

No person shall allow emissions of nitrogen oxides, calculated as nitrogen dioxide, from any nitric acid production unit to exceed 600 parts per million by volume.

§117.4210. Applicability of Federal New Source Performance Standards.

None of the provisions of this subchapter (relating to Acid Manufacturing) may be construed to limit or preclude applicability of any provision of 40 Code of Federal Regulations Part 60, Subpart G (Standards of Performance for Nitric Acid Plants).

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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SUBCHAPTER G. GENERAL MONITORING AND TESTING REQUIREMENTS
DIVISION 1. COMPLIANCE STACK TESTING AND REPORT REQUIREMENTS

30 TAC §117.8000, §117.8010

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.8000. Stack Testing Requirements.

(a) When required by this chapter, the owner or operator of a unit subject to this chapter shall conduct testing according to the requirements of this section.

(b) The unit must be operated at the maximum rated capacity, or as near as practicable. Compliance must be determined by the average of three one-hour emission test runs. Shorter test times may be used if approved by the executive director.

(c) Testing must be performed using the following test methods:

(1) Test Method 7E or 20 (40 Code of Federal Regulations (CFR), Part 60, Appendix A) for nitrogen oxides (NO_x);

(2) Test Method 10, 10A, or 10B (40 CFR 60, Appendix A) for carbon monoxide (CO);

(3) Test Method 3A or 20 (40 CFR 60, Appendix A) for oxygen (O_2);

(4) for units that inject ammonia or urea to control NO_x emissions, the Phenol-Nitroprusside Method, the Indophenol Method, or the United States Environmental Protection Agency Conditional Test Method 27 for ammonia;

(5) Test Method 2 (40 CFR 60, Appendix A) for exhaust gas flow and following the measurement site criteria of Test Method 1, §11.1 (40 CFR 60, Appendix A), or Test Method 19 (40 CFR 60, Appendix A) for exhaust gas flow in conjunction with the measurement site criteria of Performance Specification 2, §8.1.3 (40 CFR 60, Appendix B); or

(6) American Society for Testing and Materials (ASTM) Method D1945-91 or ASTM Method D3588-93 for fuel composition; ASTM Method D1826-88 or ASTM Method D3588-91 for calorific value; or alternate methods as approved by the executive director and the United States Environmental Protection Agency.

(d) United States Environmental Protection Agency-approved alternate test methods or minor modifications to the test methods specified in subsection (c) of this section may be used, as approved by the executive director, as long as the minor modifications meet the following conditions:

(1) the change does not affect the stringency of the applicable emission specification;

(2) the change affects only a single source or facility application.

§117.8010. Compliance Stack Test Reports.

Compliance stack test reports of testing performed in accordance with §117.8000 of this title (relating to Stack Testing Requirements), or if otherwise specified in this chapter, must include the following minimum contents.

(1) Introductory information. Background information pertinent to the test must include:

(A) company name, address, and name of company official responsible for submitting report;

(B) name and address of testing organization;

(C) names of persons present, dates, and location of test;

(D) schematic drawings of the unit being tested, showing emission points, sampling sites, and stack cross-section with the sampling points labeled and dimensions indicated;

(E) description of the process being sampled; and

(F) facility identification number used to identify the unit in the final control plan.

(2) Summary information. Summary information must include:

(A) a summary of emission rates found, reported in the units of the applicable emission limits and averaging periods, and compared with the applicable emission specification;

(B) the maximum rated capacity, normal maximum capacity, and actual operating level of the unit during the test (in million British thermal units, horsepower, or megawatts, as applicable), and description of the method used to determine such operating level;

(C) the operating parameters of any active nitrogen oxides (NO_x) control equipment during the test (for example, percent flue gas recirculation, ammonia flow rate, etc); and

(D) documentation that no changes to the unit have occurred since the compliance test was conducted that could result in a significant change in NO_x emissions.

(3) Procedure. The description of the procedures used and description of the operation of the sampling train and process during the test must include:

(A) a schematic drawing of the sampling devices used with each component designated and explained in a legend;

(B) a brief description of the method used to operate the sampling train and the procedure used to recover samples; and

(C) deviation from reference methods, if any.

(4) Analytical technique. A brief description of all analytical techniques used to determine the emissions from the source must be provided.

(5) Data and calculations. All data and calculations must be provided, including:

(A) field data collected on raw data sheets;

(B) log of process operating levels, including fuel data;

(C) laboratory data, including blanks, tare weights, and results of analysis; and

(D) emission calculations.

(6) Chain of custody. A listing of the chain of custody of the emission or fuel test samples, as applicable, must be provided.

(7) Appendix. The appendices must include:

(A) calibration work sheets for sampling equipment;

(B) collection of process logs of process parameters;

(C) brief resume/qualifications of test personnel; and

(D) description of applicable continuous monitoring system, as applicable.

(8) Monitor certification reports. Monitor certification reports must contain:

(A) information that demonstrates compliance with the certification requirements of §117.8100(a) or (b) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources) for any continuous emissions monitoring system or predictive emissions monitoring system, as applicable; and

(B) the relative accuracy test audit information specified in 40 Code of Federal Regulations Part 60, Appendix B, Performance Specification 2, §8.5.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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DIVISION 2. EMISSION MONITORING

30 TAC §§117.8100, 117.8110, 117.8120, 117.8130, 117.8140

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.8100. Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources.

(a) Continuous emissions monitoring system (CEMS) requirements. When required by this chapter, the owner or operator of any CEMS shall comply with the following.

(1) Except as specified in paragraph (5) of this subsection, the CEMS must meet the requirements of 40 Code of Federal Regulations (CFR) Part 60 as follows:

(A) §60.13;

(B) Appendix B:

(i) Performance Specification 2, for nitrogen oxides (NO_x) in terms of the applicable standard (in parts per million by volume (ppmv), pounds per million British thermal units (lb/MMBtu), or grams per horsepower-hour (g/hp-hr)). An alternative relative accuracy requirement of ±2.0 ppmv from the reference method mean value is allowed;

(ii) Performance Specification 3, for diluent; and

(iii) Performance Specification 4, for carbon monoxide (CO), for owners or operators electing to use a CO CEMS; and

(C) after the final applicable compliance date or date of required submittal of CEMS performance evaluation, conduct audits in accordance with §5.1 of Appendix F, quality assurance procedures for NO_x, CO, and diluent analyzers, except that a cylinder gas audit or relative accuracy audit may be performed in lieu of the annual relative accuracy test audit (RATA) required in §5.1.1. If the optional alternative relative accuracy requirement of subparagraph (B)(i) of this paragraph (or equivalent) from the reference method mean value is used, then an annual RATA must be performed.

(2) The owner or operator shall monitor diluent, either oxygen (O_2) or carbon dioxide (CO_2), unless using an exhaust flow meter that meets the flow monitoring specifications of 40 CFR Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

(3) One CEMS may be shared among units or among multiple exhaust stacks on a single unit, provided:

(A) the exhaust stream of each stack is analyzed separately; and

(B) the CEMS meets the certification requirements of paragraph (1) of this subsection for each stack while the CEMS is operating in the time-shared mode.

(4) Each individual stack must be analyzed separately for units with multiple exhaust stacks.

(5) As an alternative to paragraph (1) of this subsection, an owner or operator may choose to comply with the CEMS requirements of 40 CFR Part 75 as follows:

(A) general operation requirements in Subpart B, §75.10(a)(2);

(B) certification procedures and test methods in Subpart C, §75.20(c) and §75.22;

(C) recordkeeping requirements of the monitoring plan in Subpart D, §75.53(a) - (c);

(D) appropriate specifications and test procedures in Appendix A, as follows:

(i) §1 (Installation and Measurement Location);

(ii) §2 (Equipment Specifications);

(iii) §3 (Performance Specifications);

(iv) §4 (Data Acquisition and Handling Systems);

(v) §5 (Calibration Gas);

(vi) §6 (Certification Tests and Procedures); and

(vii) meet either the relative accuracy requirement of 40 CFR Part 75 in percentage only, or the alternative relatively accuracy requirement of ±2.0 ppmv from the reference method mean value; and

(E) appropriate quality assurance/quality control procedures in Appendix B, as follows:

(i) §1 (Quality Assurance/Quality Control Program); and

(ii) §2 (Frequency of Testing).

(6) The CEMS is subject to the approval of the executive director.

(b) Predictive emissions monitoring system (PEMS) requirements. When required by this chapter, the owner or operator of any PEMS shall comply with the following.

(1) The owner or operator shall monitor diluent, either O_2 or CO_2:

(A) using a CEMS:

(i) in accordance with subsection (a)(1)(B)(ii) of this section; or

(ii) with a similar alternative method approved by the executive director and the United States Environmental Protection Agency; or

(B) using a PEMS.

(2) Any PEMS must meet the requirements of 40 CFR Part 75, Subpart E, except as provided in paragraphs (3) and (4) of this subsection.

(3) The owner or operator may vary from 40 CFR Part 75, Subpart E if the owner or operator:

(A) demonstrates to the satisfaction of the executive director and the United States Environmental Protection Agency that the alternative is substantially equivalent to the requirements of 40 CFR Part 75, Subpart E; or

(B) demonstrates to the satisfaction of the executive director that the requirement is not applicable.

(4) The owner or operator may substitute the following as an alternative to the test procedure of Subpart E for any unit:

(A) perform the following alternative initial certification tests:

(i) conduct initial RATA at low, medium, and high levels of the key operating parameter affecting NO_x using 40 CFR Part 60, Appendix B:

(I) Performance Specification 2, subsection 13.2, pertaining to NO_x, in terms of the applicable standard (in ppmv, lb/MMBtu, or g/hp-hr). An alternative relative accuracy requirement of ±2.0 ppmv from the reference method mean value is allowed;

(II) Performance Specification 3, subsection 13.2, pertaining to O_2 or CO_2; and

(III) Performance Specification 4, subsection 13.2, pertaining to CO, for owners or operators electing to use a CO PEMS; and

(ii) conduct an F-test, a t-test, and a correlation analysis using 40 CFR Part 75, Subpart E at low, medium, and high levels of the key operating parameter affecting NO_x:

(I) calculations must be based on a minimum of 30 successive emission data points at each tested level that are either 15-minute, 20-minute, or hourly averages;

(II) the F-test must be performed separately at each tested level;

(III) the t-test and the correlation analysis must be performed using all data collected at the three tested levels;

(IV) waivers from the statistical tests and default reference method standard deviation values for the F-test may be allowed according to the *TNRCC PEMS Protocol Draft*, May 16, 1994;

(V) the correlation analysis may only be temporarily waived following review of the waiver request submittal if:

(-a-) the process design is such that it is technically impossible to vary the process to result in a concentration change sufficient to allow a successful correlation analysis statistical test. Any waiver request must also be accompanied with documentation of the reference method measured concentration, and documentation that it is less than 50% of the emission limit or standard. The waiver must be based on the measured value at the time of the waiver. Should a subsequent RATA effort identify a change in the reference method measured value by more than 30%, the statistical test must be repeated at the next RATA effort to verify the successful compliance with the correlation analysis statistical test requirement; or

(-b-) the data for a measured compound (e.g., NO_x, O_2) are determined to be autocorrelated according to the procedures of 40 CFR §75.41(b)(2). A complete analysis of autocorrelation with support information must be submitted with the request for waiver. The statistical test must be repeated at the next RATA effort to verify the successful compliance with the correlation analysis statistical test requirement; and

(VI) all requests for waivers must be submitted to the executive director for review. The executive director shall approve or deny each waiver request;

(B) further demonstrate PEMS accuracy and precision for at least one unit of a category of equipment by performing RATA and statistical testing in accordance with subparagraph (A) of this paragraph for each of three successive quarters, beginning:

(i) no sooner than the quarter immediately following initial certification; and

(ii) no later than the first quarter following the final compliance date; and

(C) after the final applicable compliance date, perform RATA for each unit:

(i) at normal load operations;

(ii) using the Performance Specifications of subparagraph (A)(i)(I) - (III) of this paragraph; and

(iii) at the following frequency:

(I) semiannually; or

(II) annually, if following the first semiannual RATA, the relative accuracy during the previous audit for each compound monitored by PEMS is less than or equal to 7.5% (or within ±2.0 ppmv) of the mean value of the reference method test data at normal load operation; or alternatively:

(-a-) for diluent, is no greater than 1.0% O_2 or CO_2, for diluent measured by reference method at less than 5% by volume; or

(-b-) for CO, is no greater than 5.0 ppmv.

(5) The owner or operator shall, for each alternative fuel fired in a unit, certify the PEMS in accordance with paragraph (4)(A) of this subsection unless the alternative fuel effects on NO_x, CO, and O_2 (or CO_2) emissions were addressed in the model training process.

(6) The PEMS is subject to the approval of the executive director.

(c) Monitoring system certification reports. Reports of any RATA performed in accordance with this section must comply with §117.8010 of this title (relating to Compliance Stack Test Reports).

§117.8110. Emission Monitoring System Requirements for Utility Electric Generation Sources.

(a) Continuous emissions monitoring system (CEMS) requirements. When required by this chapter, the owner or operator of any CEMS shall comply with the following.

(1) The CEMS must be installed, calibrated, maintained, and operated in accordance with 40 Code of Federal Regulations (CFR) Part 75 or 40 CFR Part 60, as applicable.

(2) One CEMS may be shared among units, provided:

(A) the exhaust stream of each unit is analyzed separately; and

(B) the CEMS meets the applicable certification requirements of paragraph (1) of this subsection for each exhaust stream.

(b) Predictive emissions monitoring system (PEMS) requirements. When required by this chapter, the owner or operator of any PEMS shall comply with the following.

(1) The owner or operator shall monitor diluent, either oxygen or carbon dioxide:

(A) using a CEMS:

(i) in accordance with subsection (a) of this section; or

(ii) with a similar alternative method approved by the executive director and the United States Environmental Protection Agency; or

(B) using a PEMS.

(2) Any PEMS for units subject to the requirements of 40 CFR Part 75 must meet the requirements of 40 CFR Part 75, Subpart E, §§75.40 - 75.48.

(3) Any PEMS for units not subject to the requirements of 40 CFR Part 75 must meet the requirements of either:

(A) 40 CFR Part 75, Subpart E, §§75.40 - 75.48; or

(B) §117.8100(b) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources).

§117.8120. Carbon Monoxide (CO) Monitoring.

When required by this chapter, the owner or operator shall monitor carbon monoxide (CO) exhaust emissions from an affected unit using one or more of the following methods:

(1) install, calibrate, maintain, and operate a:

(A) continuous emissions monitoring system (CEMS) in accordance with §117.8100(a) or §117.8110(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources; and Emission Monitoring System Requirements for Utility Electric Generation Sources), as applicable; or

(B) predictive emissions monitoring system (PEMS) in accordance with §117.8100(b) or §117.8110(b) of this title, as applicable; or

(2) sample CO as follows:

(A) with a portable analyzer (or 40 Code of Federal Regulations (CFR) Part 60, Appendix A reference method test apparatus) after manual combustion tuning or manual burner adjustments conducted for the purpose of minimizing nitrogen oxides (NO_x) emissions whenever, following such manual changes, either of the following occur:

(i) NO_x emissions are sampled with a portable analyzer or 40 CFR Part 60, Appendix A reference method test apparatus; or

(ii) the resulting NO_x emissions measured by CEMS or predicted by PEMS are lower than levels when CO emissions data was previously gathered; and

(B) sample CO emissions using the test methods and procedures of 40 CFR Part 60 in conjunction with any relative accuracy test audit of the NO_x and diluent analyzer.

§117.8130. Ammonia Monitoring.

When required by this chapter, one of the following ammonia monitoring procedures must be used to demonstrate compliance with the applicable ammonia emission specifications of this chapter for gas-fired or liquid-fired units that inject urea or ammonia into the exhaust stream for nitrogen oxides (NO_x) control.

(1) Mass balance. Ammonia emissions are calculated as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of the control device that injects urea or ammonia into the exhaust stream. The ammonia emissions must be calculated using the following equation.
Figure: 30 TAC §117.8130(1)

(2) Oxidation of ammonia to nitric oxide (NO). Convert ammonia to NO using a molybdenum oxidizer and measure ammonia slip by difference using a NO analyzer. The NO analyzer must be quality assured in accordance with the manufacturer's specifications and with a quarterly cylinder gas audit with a 10 parts per million by volume (ppmv) reference sample of ammonia passed through the probe and confirming monitor response to within ±2.0 ppmv.

(3) Stain tubes. Measure ammonia using a sorbent or stain tube device specific for ammonia measurement in the 5.0 to 10.0 ppmv range. The frequency of sorbent/stain tube testing must be daily for the first 60 days of operation. After the first 60 days of operation, the frequency may be reduced to weekly testing if operating procedures have been developed to prevent excess amounts of ammonia from being introduced in the control device and when operation of the control device has been proven successful with regard to controlling ammonia slip. Daily sorbent or stain tube testing must resume when the catalyst is within 30 days of its useful life expectancy. Every effort must be made to take at least one weekly sample near the normal highest ammonia injection rate.

(4) Other methods. Monitor ammonia using another continuous emissions monitoring system or predictive emissions monitoring system procedure subject to prior approval of the executive director.

§117.8140. Emission Monitoring for Engines.

(a) Periodic testing. When required by this chapter, the owner or operator of any stationary internal combustion engine shall test engine nitrogen oxides (NO_x) and carbon monoxide (CO) emissions as follows.

(1) The methods specified in §117.8000 of this title (relating to Stack Testing Requirements) must be used.

(2) The owner or operators shall sample:

(A) on a biennial calendar basis; or

(B) within 15,000 hours of engine operation after the previous emission test, under the following conditions:

(i) install and operate an elapsed operating time meter; and

(ii) submit, in writing, to the executive director and any local air pollution agency having jurisdiction, biennially after the initial demonstration of compliance:

(I) documentation of the actual recorded hours of engine operation since the previous emission test; and

(II) an estimate of the date of the next required sampling.

(3) Engines used exclusively in emergency situations are not required to conduct the testing specified in paragraph (2) of this subsection.

(b) Proper operation. When required by this chapter, the owner or operator of any stationary internal combustion engine shall check the engine for proper operation by recorded measurements of engine NO_x and CO emissions at least quarterly and as soon as practicable within two weeks after each occurrence of engine maintenance that may reasonably be expected to increase emissions, oxygen sensor replacement, or catalyst cleaning or catalyst replacement. Stain tube indicators specifically designed to measure NO_x concentrations may be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x analyzers are also acceptable for this documentation. Quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours. This exemption does not diminish the requirement to test emissions after the installation of controls, major repair work, and any time the owner or operator believes emissions may have changed.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 15, 2006.

TRD-200606733
Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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SUBCHAPTER H. ADMINISTRATIVE PROVISIONS

DIVISION 1. COMPLIANCE SCHEDULES

30 TAC §§117.9000, 117.9010, 117.9020, 117.9030, 117.9100, 117.9110, 117.9120, 117.9130, 117.9200, 117.9210, 117.9300, 117.9320, 117.9340, 117.9500

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.9000. Compliance Schedule for Beaumont-Port Arthur Ozone Nonattainment Area Major Sources.

The owner or operator of each industrial, commercial, and institutional source in the Beaumont-Port Arthur ozone nonattainment area shall comply with the requirements of Subchapter B, Division 1 of this chapter (relating to Beaumont-Port Arthur Ozone Nonattainment Area Major Sources) as soon as practicable, but no later than the dates specified in this section.

(1) Reasonably available control technology (RACT). The owner or operator shall for all units, comply with the requirements of Subchapter B, Division 1 of this chapter, except as specified in paragraph (2) of this section (relating to lean-burn engines) and paragraph (3) of this section (relating to emission specifications for attainment demonstration), by November 15, 1999 (final compliance date), and submit to the executive director:

(A) for units operating without a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS), the results of applicable tests for initial demonstration of compliance as specified in §117.135 of this title (relating to Initial Demonstration of Compliance); by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(B) for units operating with CEMS or PEMS in accordance with §117.140 of this title (relating to Continuous Demonstration of Compliance), the results of:

(i) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A) of this title (relating

to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources); and

(ii) the applicable tests for the initial demonstration of compliance as specified in §117.135 of this title;

(iii) no later than:

(I) November 15, 1999, for units complying with the nitrogen oxides (NO_x) emission specification on an hourly average; and

(II) January 15, 2000, for units complying with the NO_x emission specification on a rolling 30-day average;

(C) a final control plan for compliance in accordance with §117.152 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology), no later than November 15, 1999; and

(D) the first semiannual report required by §117.145(d) or (e) of this title (relating to Notification, Recordkeeping, and Reporting Requirements), covering the period November 15, 1999, through December 31, 1999, no later than January 31, 2000.

(2) Lean-burn engines. The owner or operator shall for each lean-burn, stationary, reciprocating internal combustion engine subject to §117.105(e) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), comply with the requirements of Subchapter B, Division 1 of this chapter for those engines as soon as practicable, but no later than November 15, 2001 (final compliance date for lean-burn engines); and

(A) no later than November 15, 2001, submit a revised final control plan that contains:

(i) the information specified in §117.152 of this title as it applies to the lean-burn engines; and

(ii) any other revisions to the source's final control plan as a result of complying with the lean-burn engine emission specifications; and

(B) no later than January 31, 2002, submit the first semiannual report required by §117.145(e) of this title covering the period November 15, 2001, through December 31, 2001.

(3) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.110(a) of this title (relating to Emission Specifications for Attainment Demonstration) as soon as practicable, but no later than:

(A) May 1, 2003, demonstrate that at least two-thirds of the NO_x emission reductions required by §117.110(a) of this title have been accomplished, as measured either by:

(i) the total number of units required to reduce emissions in order to comply with §117.110(a) of this title using direct compliance with the emission specifications, counting only units still required to reduce after May 11, 2000; or

(ii) the total amount of emissions reductions required to comply with §117.110(a) of this title using the alternative methods to comply, either:

(I) §117.115 of this title (relating to Alternative Plant-Wide Emission Specifications);

(II) §117.123 of this title (relating to Source Cap); or

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

(B) May 1, 2003, submit to the executive director:

(i) identification of enforceable emission limits that satisfy the conditions of subparagraph (A) of this paragraph;

(ii) for units operating without CEMS or PEMS or for units operating with CEMS or PEMS and complying with the NO_x emission limit on an hourly average, the results of applicable tests for initial demonstration of compliance as specified in §117.135 of this title;

(iii) for units newly operating with CEMS or PEMS to comply with the monitoring requirements of §117.140(c)(1)(C) of this title or §117.123 of this title, the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A) of this title;

(iv) the information specified in §117.154 of this title (relating to Final Control Plans Procedures for Attainment Demonstration Emission Specifications); and

(v) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.110(a) of this title;

(C) July 31, 2003, submit to the executive director:

(i) the applicable tests for the initial demonstration of compliance as specified in §117.135 of this title, for units complying with the NO_x emission specification on a rolling 30-day average; and

(ii) the first semiannual report required by §117.123(e) and §117.145(e) of this title, covering the period May 1, 2003, through June 30, 2003;

(D) May 1, 2005, comply with §117.110(a) of this title;

(E) May 1, 2005, submit a revised final control plan that contains:

(i) a demonstration of compliance with §117.110(a) of this title;

(ii) the information specified in §117.154 of this title; and

(iii) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.110(a) of this title; and

(F) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.135 of this title, if using the 30-day average source cap NO_x emission limit to comply with the emission specifications in §117.110(a) of this title.

§117.9010. Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Major Sources.

The owner or operator of each industrial, commercial, and institutional source in the Dallas-Fort Worth ozone nonattainment area shall comply with the requirements of Subchapter B, Division 2 of this chapter (relating to Dallas-Fort Worth Ozone Nonattainment Area Major Sources) as soon as practicable, but no later than March 31, 2002 (final compliance date). The owner or operator shall:

(1) install all nitrogen oxides (NO_x) abatement equipment and implement all NO_x control techniques no later than March 31, 2002; and

(2) submit to the executive director:

(A) for units operating without a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS), the results of applicable tests for initial demonstration of compliance as specified in §117.235 of this title (relating to Initial Demonstration of Compliance) as early as practicable, but in no case later than March 31, 2002;

(B) for units operating with CEMS or PEMS in accordance with §117.240 of this title (relating to Continuous Demonstration of Compliance), the results of:

(i) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources);

(ii) the applicable tests for the initial demonstration of compliance as specified in §117.235 of this title; and

(iii) no later than:

(I) March 31, 2002, for units complying with the NO_x emission specification on an hourly average; and

(II) May 31, 2002, for units complying with the NO_x emission specification on a rolling 30-day average;

(C) a final control plan for compliance in accordance with §117.252 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology), no later than March 31, 2002; and

(D) the first semiannual report required by §117.245(d) or (e) of this title (relating to Notification, Recordkeeping, and Reporting Requirements), covering the period March 31, 2002, through June 30, 2002, no later than July 31, 2002.

§117.9020. Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources.

The owner or operator of each industrial, commercial, and institutional source in the Houston-Galveston-Brazoria ozone nonattainment area shall comply with the requirements of Subchapter B, Division 3 of this chapter (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources) as soon as practicable, but no later than the dates specified in this section.

(1) Reasonably available control technology. The owner or operator shall, for all units, comply with the requirements of Subchapter B, Division 3 of this chapter, except as specified in paragraph (2) of this section, by November 15, 1999 (final compliance date); and

(A) submit a plan for compliance in accordance with §117.350 of this title (relating to Initial Control Plan Procedures) according to the following schedule:

(i) for major sources of nitrogen oxides (NO_x) that have units subject to emission specifications under this chapter, submit an initial control plan for all such units no later than April 1, 1994;

(ii) for major sources of NO_x that have no units subject to emission specifications under this chapter, submit an initial control plan for all such units no later than September 1, 1994; and

(iii) for major sources of NO_x subject to either clause (i) or (ii) of this subparagraph, submit the information required by §117.350(c)(6), (7), and (9) of this title no later than September 1, 1994;

(B) install all NO_x abatement equipment and implement all NO_x control techniques no later than November 15, 1999; and

(C) submit to the executive director:

(i) for units operating without a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS), the results of applicable tests for initial demonstration of compliance as specified in §117.335 of this title (relating to Initial Demonstration of Compliance); by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(ii) for units operating with CEMS or PEMS in accordance with §117.340 of this title (relating to Continuous Demonstration of Compliance), submit the results of:

(I) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources); and

(II) the applicable tests for the initial demonstration of compliance as specified in §117.335 of this title;

(III) no later than:

(-a-) November 15, 1999, for units complying with the NO_x emission specification on an hourly average; and

(-b-) January 15, 2000, for units complying with the NO_x emission specification on a rolling 30-day average;

(iii) a final control plan for compliance in accordance with §117.352 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology), no later than November 15, 1999; and

(iv) the first semiannual report required by §117.345(d) or (e) of this title (relating to Notification, Recordkeeping, and Reporting Requirements), covering the period November 15, 1999, through December 31, 1999, no later than January 31, 2000.

(2) Emission specifications for attainment demonstration.

(A) The owner or operator of any unit subject to §117.310(a) (relating to Emission Specifications for Attainment Demonstration) shall comply with the requirements of §117.340 of this title as follows.

(i) As soon as practicable, but no later than March 31, 2005, the owner or operator shall install any totalizing fuel flow meters, run time meters, and emissions monitors required by §117.340 of this title, except that if flue gas cleanup (for example, controls that use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.340 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit. However, an owner or operator may choose to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until March 31, 2005.

(I) Within 60 days after startup of a unit following installation of emissions monitors, the owner or operator shall submit to the executive director the results of the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A) of this title; or

(II) If the unit is shut down as of March 31, 2005, the CEMS or PEMS performance evaluation and quality assurance procedures must be submitted to the executive director within 60 days after the startup of the unit after March 31, 2005.

(ii) Within 60 days after startup of a unit following installation of emissions controls, the owner or operator shall submit to the executive director the results of:

(I) stack tests conducted in accordance with §117.335 of this title. For a stack test conducted before March 31,

2005, on a unit not equipped with CEMS or PEMS that CEMS or PEMS must be installed no later than March 31, 2005, the requirements of §117.335(c) of this title do not apply; or, as applicable,

(II) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A) of this title.

(B) The owner or operator of each electric generating facility (EGF) shall:

(i) no later than June 30, 2001, submit to the executive director the certification of level of activity, H_i, specified in §117.320 of this title (relating to System Cap) for each EGF in operation as of January 1, 1997;

(ii) no later than 60 days after the end of the first five years of operation, submit to the executive director the certification of activity level, H_i, based on any two consecutive third quarters of actual level of activity data available from the first five years of operation as specified in §117.320 of this title for each EGF not in operation prior to January 1, 1997; and

(iii) comply with the requirements of §117.320 of this title as soon as practicable, but no later than March 31, 2007.

(C) For any units subject to §117.310(a) of this title that stack testing or the CEMS or PEMS performance evaluation and quality assurance has not been conducted under subparagraph (A) of this paragraph or units placed into service after March 31, 2005, that do not have flue gas cleanup, the owner or operator shall submit to the executive director as soon as practicable, but no later than March 31, 2007, the results of:

(i) stack tests conducted in accordance with §117.335 of this title; or, as applicable,

(ii) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A) of this title.

(D) The owner or operator shall comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) as soon as practicable, but no later than the appropriate dates specified in that program.

(E) For diesel and dual-fuel engines, the owner or operator shall comply with the restriction on hours of operation for maintenance or testing, and associated recordkeeping, as soon as practicable, but no later than April 1, 2002.

(F) The owner or operator shall comply with all other requirements of Subchapter B, Division 3 of this chapter as soon as practicable, but no later than March 31, 2005.

(G) The owner or operator of a unit that is subject to §117.310(a) of this title and will be permanently shut down on or before September 30, 2005, may elect to comply with §117.340(a) and (c) - (f) of this title by performing testing in lieu of the monitoring requirements, provided that following conditions are met:

(i) submit written notification to the executive director no later than March 31, 2005, containing the following:

(I) a list of units, by emission point number, that the owner or operator will permanently shut down on or before September 30, 2005;

(II) the projected date(s) that each unit will be permanently shut down; and

(III) the projected date(s) of the testing to be performed in accordance with clause (ii) of this subparagraph;

(ii) the testing is performed in accordance with §117.335 of this title after March 31, 2005, and prior to September 30, 2005, while operating at maximum rated capacity, or as near thereto as practicable. For the time period from March 31, 2005, to September 30, 2005, the results of this testing must be used for demonstrating compliance with the emission specifications in §117.310(a) of this title or to quantify the emissions for units subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title;

(iii) for units that a totalizing fuel flow meter has not been installed as required in §117.340(a) of this title, the maximum rated capacity of the unit must be used to quantify the emissions for units subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title; and

(iv) if the unit is not shut down by September 30, 2005, the owner or operator will be considered in violation of this section as of March 31, 2005, and extensions beyond September 30, 2005, will not be granted.

§117.9030. Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources.

(a) Increment of progress emission specifications. The owner or operator of any stationary, reciprocating internal combustion engine subject to §117.410(a) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) shall comply with the requirements of §117.410(a) of this title as soon as practicable, but no later than June 15, 2007 (the final compliance date). The owner or operator shall:

(1) install all nitrogen oxides (NO_x) abatement equipment and implement all NO_x control techniques no later than June 15, 2007; and

(2) submit to the executive director:

(A) for units operating without a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS), the results of applicable tests for initial demonstration of compliance as specified in §117.435 of this title (relating to Initial Demonstration of Compliance) as early as practicable, but in no case later than June 15, 2007;

(B) for units operating with a CEMS or PEMS in accordance with §117.440 of this title (relating to Continuous Demonstration of Compliance), the results of:

(i) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources);

(ii) the applicable tests for the initial demonstration of compliance as specified in §117.435 of this title; and

(iii) no later than:

(I) June 15, 2007, for units complying with the NO_x emission limit on an hourly average; and

(II) June 15, 2007, for units complying with the NO_x emission limit on a rolling 30-day average;

(C) a final control plan for compliance in accordance with §117.454 of this title (relating to Final Control Plan Procedures for Attainment Demonstration Emission Specifications), no later than January 1, 2008; and

(D) the first semiannual report required by §117.445(d) or (e) of this title (relating to Notification, Recordkeeping, and Reporting Requirements), covering the period June 15, 2007, through December 31, 2007, no later than January 31, 2008.

(b) Eight-hour ozone attainment demonstration emission specifications.

(1) The owner or operator of any stationary source of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area that is a major source of NO_x and is subject to §117.410(b) of this title shall comply with the requirements of Subchapter B, Division 4 of this chapter (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources) as follows:

(A) submit the initial control plan required by §117.450 of this title (relating to Initial Control Plan Procedures) no later than June 1, 2008; and

(B) comply with all other requirements of Subchapter B, Division 4 of this chapter as soon as practicable, but no later than March 1, 2009.

(2) The owner or operator of any stationary source of NO_x that becomes subject to the requirements of Subchapter B, Division 4 of this chapter on or after March 1, 2009, shall comply with the requirements of Subchapter B, Division 4 of this chapter as soon as practicable, but no later than 60 days after becoming subject.

§117.9100. Compliance Schedule for Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources.

The owner or operator of each electric utility in the Beaumont-Port Arthur ozone nonattainment area shall comply with the requirements of Subchapter C, Division 1 of this chapter (relating to Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources) as soon as practicable, but no later than the dates specified in this section.

(1) Reasonably available control technology (RACT). The owner or operator shall for all units, comply with the requirements of Subchapter C, Division 1 of this chapter as soon as practicable, but no later than November 15, 1999 (final compliance date), except as specified in subparagraph (D) of this paragraph, relating to oil firing, and paragraph (2) of this section, relating to emission specifications for attainment demonstration:

(A) conduct applicable continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) evaluations and quality assurance procedures as specified in §117.1040 of this title (relating to Continuous Demonstration of Compliance) according to the following schedules:

(i) for equipment and software required under 40 Code of Federal Regulations (CFR) Part 75, no later than January 1, 1995, for units firing coal, and no later than July 1, 1995, for units firing natural gas or oil; and

(ii) for equipment and software not required under 40 CFR Part 75, no later than November 15, 1999;

(B) install all nitrogen oxides (NO_x) abatement equipment and implement all NO_x control techniques no later than November 15, 1999;

(C) submit to the executive director:

(i) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.1035 of this title (relating to Initial Demonstration of Compliance); by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(ii) for units operating with CEMS or PEMS in accordance with §117.1040 of this title, the results of:

(I) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.1040 of this title; and

(II) the applicable tests for the initial demonstration of compliance as specified in §117.1035 of this title;

(III) no later than:

(-a-) November 15, 1999, for units complying with the NO_x emission specification on an hourly average; and

(-b-) January 15, 2000, for units complying with the NO_x emission specification on a rolling 30-day average;

(D) conduct applicable tests for initial demonstration of compliance with the NO_x emission specification for fuel oil firing, in accordance with §117.1035(d)(2) of this title, and submit test results within 60 days after completion of such testing; and

(E) submit a final control plan for compliance in accordance with §117.1052 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology), no later than November 15, 1999.

(2) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.1010(a) of this title (relating to Emission Specifications for Attainment Demonstration) as soon as practicable, but no later than:

(A) May 1, 2003, demonstrate that at least two-thirds of the NO_x emission reductions required by §117.1010(a) of this title have been accomplished, as measured either by:

(i) the total number of units required to reduce emissions in order to comply with §117.1010(a) of this title using direct compliance with the emission specifications, counting only units still required to reduce after May 11, 2000; or

(ii) the total amount of emissions reductions required to comply with §117.1010(a) of this title using the alternative methods to comply, either:

(I) §117.1020 of this title (relating to System Cap); or

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

(B) May 1, 2003, submit to the executive director:

(i) identification of enforceable emission limits that satisfy subparagraph (A) of this paragraph;

(ii) the information specified in §117.1054 of this title (relating to Final Control Plan Procedures for Attainment Demonstration Emission Specifications) to comply with subparagraph (A) of this paragraph; and

(iii) any other revisions to the source's final control plan as a result of complying with subparagraph (A) of this paragraph;

(C) May 1, 2003, install CEMS or PEMS on previously exempt units and conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.1040 of this title;

(D) July 31, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.1035 of this title, if using the 30-day average system cap to comply with subparagraph (A) of this paragraph;

(E) May 1, 2005, comply with §117.1010(a) of this title;

(F) May 1, 2005, submit a revised final control plan that contains:

(i) a demonstration of compliance with §117.1010(a) of this title;

(ii) the information specified in §117.1054 of this title; and

(iii) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.1010(a) of this title; and

(G) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.1035 of this title, if using the 30-day average system cap NO_x emission limit to comply with the emission specifications in §117.1010(a) of this title.

§117.9110. Compliance Schedule for Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources.

The owner or operator of each electric utility in the Dallas-Fort Worth ozone nonattainment area shall comply with the requirements of Subchapter C, Division 2 of this chapter (relating to Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources) as soon as practicable, but no later than the dates specified in this section.

(1) Reasonably available control technology (RACT). The owner or operator shall comply with the requirements of Subchapter C, Division 2 of this chapter as soon as practicable, but no later than March 31, 2001 (final compliance date), except as provided in subparagraph (D) of this paragraph, relating to oil firing, and paragraph (2) of this section, relating to emission specifications for attainment demonstration:

(A) conduct applicable continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) evaluations and quality assurance procedures as specified in §117.1140 of this title (relating to Continuous Demonstration of Compliance) no later than March 31, 2001;

(B) install all nitrogen oxides (NO_x) abatement equipment and implement all NO_x control techniques no later than March 31, 2001;

(C) submit to the executive director:

(i) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.1135 of this title (relating to Initial Demonstration of Compliance) no later than March 31, 2001;

(ii) for units operating with CEMS or PEMS in accordance with §117.1140 of this title, the results of:

(I) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.1140 of this title; and

(II) the applicable tests for the initial demonstration of compliance as specified in §117.1135 of this title;

(III) no later than:

(-a-) March 31, 2001, for units complying with the NO_x emission specification in pounds per hour on a block one-hour average; and

(-b-) May 31, 2001, for units complying with the NO_x emission specification on a rolling 30-day average;

(D) conduct applicable tests for initial demonstration of compliance with the NO_x emission specification for fuel oil firing, in accordance with §117.1135(d)(2) of this title, and submit test results within 60 days after completion of such testing; and

(E) submit a final control plan for compliance in accordance with §117.1152 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology), no later than March 31, 2001.

(2) Emission specifications for attainment demonstration.

(A) The owner or operator shall comply with the requirements of §117.1110(a) of this title (relating to Emission Specifications for Attainment Demonstration) as soon as practicable, but no later than:

(i) May 1, 2003, demonstrate that at least two-thirds of the NO_x emission reductions required by §117.1110(a) of this title have been accomplished, as measured either by:

(I) the total number of units required to reduce emissions in order to comply with §117.1110(a) of this title using direct compliance with the emission specifications, counting only units still required to reduce after May 11, 2000; or

(II) the total amount of emissions reductions required to comply with §117.1110(a) of this title using the alternative methods to comply, either:

(-a-) §117.1120 of this title (relating to System Cap); or

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

(ii) May 1, 2003, submit to the executive director:

(I) identification of enforceable emission limits that satisfy clause (i) of this subparagraph;

(II) the information specified in §117.1154 of this title (relating to Final Control Plan Procedures for Attainment Demonstration Emission Specifications) to comply with clause (i) of this subparagraph; and

(III) any other revisions to the source's final control plan as a result of complying with clause (i) of this subparagraph;

(iii) May 1, 2003, install CEMS or PEMS on previously exempt units and conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.1140 of this title;

(iv) July 31, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.1135 of this title, if using the 30-day average system cap to comply with clause (i) of this subparagraph;

(v) May 1, 2005, comply with §117.1110(a) of this title;

(vi) May 1, 2005, submit a revised final control plan that contains:

(I) a demonstration of compliance with §117.1110(a) of this title;

(II) the information specified in §117.1154 of this title; and

(III) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.1110(a) of this title; and

(vii) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.1135 of this title, if using the 30-day average system cap NO_x emission limit to comply with the emission specifications in §117.1110(a) of this title.

(B) The requirements of subparagraph (A)(i) of this paragraph may be modified as follows. Boilers that are to be retired and decommissioned before May 1, 2005, are not required to install controls by May 1, 2003, if the following conditions are met:

(i) the boiler is designated by the Public Utility Commission of Texas to be necessary to operate for reliability of the electric system;

(ii) the owner provides the executive director an enforceable written commitment by May 1, 2003, to retire and permanently decommission the boiler by May 1, 2005;

(iii) the utility boiler is retired and permanently decommissioned by May 1, 2005; and

(iv) by May 1, 2003, all remaining boilers (those not designated for retirement and decommissioning as specified in clauses (i) - (iii) of this subparagraph) within the electric utility system are controlled to achieve at least two-thirds of the NO_x emission reductions from units not being retired and decommissioned.

§117.9120. Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources.

The owner or operator of each electric utility in the Houston-Galveston-Brazoria ozone nonattainment area shall comply with the requirements of Subchapter C, Division 3 of this chapter (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources) as soon as practicable, but no later than the dates specified in this section.

(1) Reasonably available control technology. The owner or operator shall, for all units, comply with the requirements of Subchapter C, Division 3 of this chapter as soon as practicable, but no later than November 15, 1999 (final compliance date), except as specified in subparagraph (D) of this paragraph, relating to oil firing, and paragraph (2) of this section:

(A) conduct applicable continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) evaluations and quality assurance procedures as specified in §117.1240 of this title (relating to Continuous Demonstration of Compliance) according to the following schedules:

(i) for equipment and software required under 40 Code of Federal Regulations (CFR) Part 75, no later than January 1, 1995, for units firing coal, and no later than July 1, 1995, for units firing natural gas or oil; and

(ii) for equipment and software not required under 40 CFR Part 75, no later than November 15, 1999;

(B) install all nitrogen oxides (NO_x) abatement equipment and implement all NO_x control techniques no later than November 15, 1999;

(C) submit to the executive director:

(i) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.1235 of this title (relating to Initial Demonstration of Compliance); by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(ii) for units operating with CEMS or PEMS in accordance with §117.1240 of this title, the results of:

(I) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.1240 of this title; and

(II) the applicable tests for the initial demonstration of compliance as specified in §117.1235 of this title;

(III) no later than:

(-a-) November 15, 1999, for units complying with the NO_x emission specification on an hourly average; and

(-b-) January 15, 2000, for units complying with the NO_x emission specification on a rolling 30-day average;

(D) conduct applicable tests for initial demonstration of compliance with the NO_x emission specification for fuel oil firing, in accordance with §117.1235(d)(2) of this title, and submit test results within 60 days after completion of such testing; and

(E) submit a final control plan for compliance in accordance with §117.1252 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology), no later than November 15, 1999.

(2) Emission specifications for attainment demonstration.

(A) The owner or operator of a unit subject to §117.1210(a) of this title (relating to Emission Specifications for Attainment Demonstration) shall comply with the requirements of §117.1240 of this title as soon as practicable, but no later than:

(i) March 31, 2005, install any totalizing fuel flow meters and emissions monitors required by §117.1240 of this title, except that if flue gas cleanup (for example, controls that use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.1240 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit. However, an owner or operator may choose to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until March 31, 2005; and

(ii) 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(I) stack tests conducted in accordance with §117.1235 of this title; or, as applicable,

(II) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.1240 of this title.

(B) The owner or operator shall:

(i) no later than June 30, 2001, submit to the executive director the certification of level of activity, H_i, specified in §117.1220 of this title (relating to System Cap) for electric generating facilities (EGFs) in operation as of January 1, 1997;

(ii) no later than 60 days after the second consecutive third quarter of actual level of activity level data are available, submit to the executive director the certification of activity level, H_i, specified in §117.1220 of this title for EGFs not in operation prior to January 1, 1997; and *(iii)* comply with the requirements of §117.1220 of this title as soon as practicable, but no later than:

(I) March 31, 2003, demonstrate that at least 50% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.1220 of this title; and

(II) March 31, 2004, submit the information specified in §117.1254 of this title (relating to Final Control Plan Procedures for Attainment Demonstration Emission Specifications);

(III) March 31, 2004, demonstrate compliance with the system cap limit of §117.1220 of this title.

(C) For any unit subject to §117.1210(a) of this title that stack testing or a CEMS or PEMS performance evaluation and quality assurance has not been conducted under subparagraph (A)(ii) of this paragraph, the owner or operator shall submit to the executive director as soon as practicable, but no later than March 31, 2007, the results of:

(i) stack tests conducted in accordance with §117.1235 of this title; or, as applicable,

(ii) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.1240 of this title.

(D) The owner or operator shall comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) as soon as practicable, but no later than the appropriate dates specified in that program.

§117.9130. Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources.

(a) The owner or operator of each electric utility in the Dallas-Fort Worth eight-hour ozone nonattainment area shall comply with the requirements of Subchapter C, Division 4 of this chapter (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources) as soon as practicable, but no later than as follows:

(1) submit the initial control plan required by §117.1350 of this title (relating to Initial Control Plan Procedures) no later than June 1, 2008; and

(2) comply with all other requirements of Subchapter C, Division 4 of this chapter as soon as practicable, but no later than March 1, 2009.

(b) The owner or operator of any unit in the Dallas-Fort Worth eight-hour ozone nonattainment area of nitrogen oxides that becomes subject to the requirements of Subchapter C, Division 4 of this chapter on or after March 1, 2009, shall comply with the requirements of Subchapter C, Division 4 of this chapter as soon as practicable, but no later than 60 days after becoming subject.

§117.9200. Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Minor Sources.

The owner or operator of each stationary source of nitrogen oxides (NO_x) in the Houston-Galveston-Brazoria ozone nonattainment area that is not a major source of NO_x shall comply with the requirements of Subchapter D, Division 1 of this chapter (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Minor Sources) as follows.

(1) For sources subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the owner or operator shall:

(A) install any totalizing fuel flow meters and run time meters required by §117.2035 of this title (relating to Monitoring and Testing Requirements) and begin keeping records of fuel usage as required by §117.2045 of this title (relating to Recordkeeping and Reporting Requirements) no later than March 31, 2005, except that if flue gas cleanup (for example, controls that use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.2035 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit. However, an owner or operator may choose to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until March 31, 2005;

(B) no later than 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(i) stack tests conducted in accordance with §117.2035 of this title. For a stack test conducted before March 31, 2005, on a unit not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) that CEMS or PEMS must be installed no later than March 31, 2005, the requirements of §117.2035(e)(6) of this title do not apply; or, as applicable,

(ii) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources). The applicable CEMS or PEMS performance evaluation and quality assurance procedures must be submitted no later than March 31, 2005, except that if the unit is shut down as of March 31, 2005, the CEMS or PEMS performance evaluation and quality assurance procedures must be submitted within 60 days after startup of the unit after March 31, 2005;

(C) no later than March 31, 2005, for any units subject to §117.2010 of this title (relating to Emission Specifications) that stack testing or a CEMS or PEMS performance evaluation and quality assurance has not been conducted under subparagraph (B) of this paragraph, submit to the executive director the results of:

(i) stack tests conducted in accordance with §117.2035 of this title; or, as applicable,

(ii) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A) of this title;

(D) comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title as soon as practicable, but no later than the appropriate dates specified in that program;

(E) for diesel and dual-fuel engines, comply with the restriction on hours of operation for maintenance or testing, and associated recordkeeping, as soon as practicable, but no later than April 1, 2002; and

(F) comply with all other requirements of Subchapter D, Division 1 of this chapter as soon as practicable, but no later than March 31, 2005.

(2) For sources not subject to Chapter 101, Subchapter H, Division 3 of this title, the owner or operator shall:

(A) install any totalizing fuel flow meters and run time meters required by §117.2035 of this title and begin keeping records of fuel usage as required by §117.2045 of this title no later than March 31, 2005, except that if flue gas cleanup (for example, controls that use a chemical reagent for reduction of NO_x) is installed on a unit before

March 31, 2005, then the emissions monitors required by §117.2035 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit. However, an owner or operator may choose to demonstrate compliance with the ammonia monitoring requirements through annual ammonia stack testing until March 31, 2005;

(B) no later than 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(i) stack tests conducted in accordance with §117.2035 of this title. For a stack test conducted before March 31, 2005, on a unit not equipped with a CEMS or PEMS that CEMS or PEMS must be installed no later than March 31, 2005, the requirements of §117.2035(e)(6) of this title do not apply; or, as applicable,

(ii) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.8100(a)(1)(A) and (B) and (b)(2) - (4)(A) of this title. The applicable CEMS or PEMS performance evaluation and quality assurance procedures must be submitted no later than March 31, 2005, except that if the unit is shut down as of March 31, 2005, the CEMS or PEMS performance evaluation and quality assurance procedures must be submitted within 60 days after startup of the unit after March 31, 2005;

(C) for diesel and dual-fuel engines, comply with the restriction on hours of operation for maintenance or testing, and associated recordkeeping, as soon as practicable, but no later than April 1, 2002; and

(D) comply with all other requirements of Subchapter D, Division 1 of this chapter as soon as practicable, but no later than March 31, 2005.

§117.9210. Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources.

(a) The owner or operator of any stationary source of nitrogen oxides (NO_x) in the Dallas-Fort Worth eight-hour ozone nonattainment area that is not a major source of NO_x and is subject to the requirements of Subchapter D, Division 2 of this chapter (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources) shall comply with the requirements of Subchapter D, Division 2 of this chapter as soon as practicable, but no later than March 1, 2009.

(b) The owner or operator of any stationary source of NO_x that becomes subject to the requirements of Subchapter D, Division 2 of this chapter on or after March 1, 2009, shall comply with the requirements of Subchapter D, Division 2 of this chapter as soon as practicable, but no later than 60 days after becoming subject.

§117.9300. Compliance Schedule for Utility Electric Generation in East and Central Texas.

The owner or operator of each utility electric power boiler or stationary gas turbine located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, and Wharton Counties shall comply with the requirements of Subchapter E, Division 1 of this chapter (relating to Utility Electric Generation in East and Central Texas) as soon as practicable, but no later than the following dates:

(1) except as provided in subparagraph (C) of this paragraph, May 1, 2003, for units owned by utilities subject to the cost-recovery provisions of Texas Utilities Code, §39.263(b):

(A) the owner or operator shall use the period of May 1, 2003, through April 30, 2004, for the initial annual compliance period. Compliance for each subsequent annual period is on a calendar year basis. For example, the second annual compliance period is January 1, 2004, through December 31, 2004;

(B) the updated final control plan required by §117.3054 of this title (relating to Final Control Plan Procedures) must be submitted by May 31, 2004, and by January 31, 2005; and

(C) the owner or operator shall comply with the ammonia specification of §117.3010(2) of this title (relating to Emission Specifications) by May 1, 2005; and

(2) May 1, 2005, for all other units:

(A) the owner or operator shall use the period of May 1, 2005, through April 30, 2006, for the initial annual compliance period. Compliance for each subsequent annual period is on a calendar year basis. For example, the second annual compliance period is January 1, 2006, through December 31, 2006; and

(B) the updated final control plan required by §117.3054 of this title must be submitted by May 31, 2006, and by January 31, 2007.

§117.9320. Compliance Schedule for Cement Kilns.

(a) Except as specified in subsection (c) of this section, the owner or operator of each portland cement kiln placed into service before December 31, 1999, in Bexar, Comal, Ellis, Hays, and McLennan Counties shall be in compliance with the requirements of Subchapter E, Division 2 of this chapter (relating to Cement Kilns) as soon as practicable, but no later than the following dates:

(1) May 1, 2003, for cement kilns in Ellis County; and

(2) May 1, 2005, for cement kilns in Bexar, Comal, Hays, and McLennan Counties.

(b) Notwithstanding subsection (a)(1) of this section, for a cement kiln in Ellis County that the owner or operator has filed an application for modification of its facility to meet the requirements of Subchapter E, Division 2 of this chapter on or before May 30, 2003, the compliance schedule is extended until six months after the issuance of the permit for operation of a low-NO_x burner and 12 months after issuance of the permit for operation of a secondary combustion system. Such application(s) must relate only to those modifications required to comply with Subchapter E, Division 2 of this chapter, and any issues incident thereto.

(c) The owner or operator of each portland cement kiln in Ellis County shall comply with the requirements of §117.3123 and §117.3142 of this title (relating to Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements; and Emission Testing and Monitoring for Eight-Hour Attainment Demonstration), and the applicable requirements of §117.3145 of this title (relating to Notification, Recordkeeping, and Reporting Requirements) that are associated with §117.3123 and §117.3142 of this title, as soon as practicable, but no later than March 1, 2009. The provisions regarding extension of compliance schedules in subsection (b) of this section do not apply to this subsection or the requirements of §117.3123, §117.3142, or the applicable requirements of §117.3145 of this title.

§117.9340. Compliance Schedule for East Texas Combustion.

(a) The owner or operator of each stationary, reciprocating internal combustion engine subject to the requirements of Subchapter E, Division 4 of this chapter (relating to East Texas Combustion) shall comply with the requirements of Subchapter E, Division 4 of this chapter as soon as practicable, but no later than March 1, 2009.

(b) The owner or operator of a stationary, reciprocating internal combustion engine that becomes subject to the requirements of Subchapter E, Division 4 of this chapter on or after March 1, 2009, shall comply with the requirements of Subchapter E, Division 4 of this chapter as soon as practicable, but no later than 60 days after becoming subject.

§117.9500. Compliance Schedule for Nitric Acid and Adipic Acid Manufacturing Sources.

All persons affected by the provisions of Subchapter F, Division 1 of this chapter (relating to Adipic Acid Manufacturing) or the provisions of Subchapter F, Division 2 of this chapter (relating to Nitric Acid Manufacturing-Ozone Nonattainment Areas) shall be in compliance as soon as practicable, but no later than November 15, 1999 (final compliance date). All affected persons shall meet the following compliance schedules and submit written notification to the executive director:

(1) no later than April 1, 1994, submit a control plan for compliance as specified in §117.4050 of this title and §117.4150 of this title (relating to Control Plan Procedures);

(2) conduct applicable continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) performance evaluation and quality assurance procedures as specified in §117.4040 and §117.4140 of this title (relating to Continuous Demonstration of Compliance); provide previous testing documentation for any claimed test waiver as allowed by §117.4035(d) or §117.4135(d) of this title (relating to Initial Demonstration of Compliance); and conduct applicable initial demonstration of compliance testing as specified in §117.4035 and §117.4135 of this title, by:

(A) no later than January 1, 1994, for affected facilities not performing process modification or installation of a CEMS or PEMS device as part of the control plan specified in §117.4050 and §117.4150 of this title; and

(B) no later than November 15, 1999, for affected facilities performing process modification or installation of a CEMS or PEMS device as part of the control plan specified in §117.4050 and §117.4150 of this title;

(3) within 60 days after the applicable date specified in paragraph (2)(A) or (B) of this section, submit the results of CEMS or PEMS performance evaluation and quality assurance procedures and the results of initial demonstration of compliance testing specified in paragraph (2) of this section.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 15, 2006.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
Earliest possible date of adoption: January 28, 2007
For further information, please call: (512) 239-5017

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DIVISION 2. COMPLIANCE FLEXIBILITY

30 TAC §117.9800, §117.9810

STATUTORY AUTHORITY

The new sections are proposed 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 proposed 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 proposed under federal mandates contained in 42 United States Code, §§7410 *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 proposed sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.016, 382.021, and 382.051(d).

§117.9800. Use of Emission Credits for Compliance.

(a) An owner or operator of a unit not subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) may meet emission control requirements of the sections specified in paragraphs (1) - (8) of this subsection, in whole or in part, by obtaining an emission reduction credit (ERC), mobile emission reduction credit (MERC), discrete emission reduction credit (DERC), or mobile discrete emission reduction credit (MDERC) in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title (relating to Emission Credit Banking and Trading; and Discrete Emission Credit Banking and Trading), unless there are federal or state regulations or permits under the same commission account number that contain a condition or conditions precluding such use:

(1) §§117.105, 117.205, 117.305, 117.1005, 117.1105, or 117.1205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT));

(2) §§117.110, 117.210, 117.1010, or 117.1110 of this title (relating to Emission Specifications for Attainment Demonstration);

(3) §§117.1015, 117.1115, or 117.1215 of this title (relating to Alternative System-Wide Emission Specifications);

(4) §§117.115, 117.215, or 117.315 of this title (relating to Alternative Plant-Wide Emission Specifications);

(5) §§117.123, 117.223, 117.323, 117.423, or §117.3120 of this title (relating to Source Cap);

(6) §§117.2010, 117.3010, or 117.3110 of this title (relating to Emission Specifications);

(7) §§117.410, 117.1310, 117.2110, or 117.3310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration); or

(8) §117.3123 of this title (relating to Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements).

(b) An owner or operator of a unit subject to §§117.320, 117.1020, 117.1120, 117.1220, or 117.3020 of this title (relating to System Cap) may meet the emission control requirements of these sections in whole or in part, by complying with the requirements of Chapter 101, Subchapter H, Division 5 of this title (relating to System Cap Trading) or by obtaining an ERC, MERC, DERC, or MDERC in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title, unless there are federal or state regulations or permits under the same commission account number that contain a condition or conditions precluding such use.

(c) For the purposes of this section, the term "reduction credit (RC)" refers to an ERC, MERC, DERC, or MDERC, whichever is applicable.

(d) Any lower nitrogen oxides (NO_x) emission specification established under this chapter for the unit or units using RCs requires the user of the RCs to obtain additional RCs in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title and/or otherwise reduce emissions prior to the effective date of such rule change. For units using RCs in accordance with this section that are subject to new, more stringent rule limitations, the owner or operator using the RCs shall submit a revised final control plan to the executive director in accordance with §§117.156, 117.256, 117.356, 117.456, 117.1056, 117.1156, 117.1256, and 117.1356 of this title (relating to Revision of Final Control Plan) to revise the basis for compliance with the emission specifications of this chapter. The owner or operator using the RCs shall submit the revised final control plan as soon as practicable, but no later than 90 days prior to the effective date of the new, more stringent rule. The owner or operator of the unit(s) currently using RCs shall calculate the necessary emission reductions per unit as follows.
Figure: 30 TAC §117.9800(d)

§117.9810. Use of Emission Reductions Generated from the Texas Emissions Reduction Plan (TERP).

(a) An owner or operator of a unit located in the Dallas-Fort Worth eight-hour ozone nonattainment area or in the Houston-Galveston-Brazoria ozone nonattainment area that is not subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) may meet emission control requirements of the sections specified in paragraphs (1) - (6) of this subsection, by obtaining emission reductions generated from the TERP as specified in subsection (b) of this section:

(1) §§117.205, 117.305, 117.1105, or 117.1205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT));

(2) §117.210 or §117.1110 of this title (relating to Emission Specifications for Attainment Demonstration);

(3) §117.215 or §117.315 of this title (relating to Alternative Plant-Wide Emission Specifications);

(4) §117.1120 of this title (relating to System Cap);

(5) §117.223 or §117.323 of this title (relating to Source Cap); or

(6) §117.410 or §117.1310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration).

(b) An owner or operator may obtain emission reductions generated from TERP, as provided in subsection (a) of this section, if:

(1) the owner or operator of the site as defined in §122.10 of this title (relating to General Definitions) contributes to the TERP fund, $75,000 per ton of nitrogen oxides emissions used, not to exceed 25 tons per year or 0.5 tons per day on a site-wide basis;

(2) the owner or operator of the site demonstrates to the executive director that the site will be in full compliance with the applicable emission reduction requirements of this chapter no later than the fifth anniversary of the date that the emission reductions would otherwise be required;

(3) emissions from the site are reduced by at least 80% of the required reductions;

(4) the reductions accomplished under the TERP have not been previously used to meet reduction requirements under a state implementation plan attainment demonstration;

(5) the reductions accomplished under the TERP are used in the same nonattainment area that they are generated; and

(6) the executive director approves a petition submitted by the owner or operator of the site that demonstrates that it is technically infeasible to comply with applicable emission reduction requirements of this chapter above 80% of the required reductions. When considering technical infeasibility the executive director may consider, but will not be limited to:

(A) current technology;

(B) adaptability of technology to a particular source;

(C) age and projected useful life of a source; and

(D) cost benefits at the time of application.

(c) The emissions reductions funded under the TERP, and used to offset commission requirements, must be used to benefit the community where the site using the emissions reductions is located. If there are no eligible emissions reduction projects within the community, the commission may authorize projects in an adjacent community. For purposes of this section, a community means a Justice of the Peace precinct.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

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Robert Martinez
Director, Environmental Law Division
Texas Commission on Environmental Quality
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For further information, please call: (512) 239-5017

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TITLE 40. SOCIAL SERVICES AND ASSISTANCE

Figure 1: 30 TAC Chapter 117--Preamble

Proposed New Rules and Modifications to Chapter 117

The following is a list of the sections of 30 TAC Chapter 117 with proposed new rules and modifications. Other portions of Chapter 117 included with this rulemaking are existing language proposed for reformatting purposes only.

New/Modified Chapter 117 Sections for DFW Eight-Hour Ozone SIP Rulemaking

SUBCHAPTER A: DEFINITIONS	§117.10(2), (14), (24), (29), (44), and (51)
SUBCHAPTER B: COMBUSTION CONTROL AT MAJOR INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL SOURCES IN OZONE NONATTAINMENT AREAS	
Division 4: Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources	§§117.400 - 117.456
- Exemption from Subchapter B, Division 2 after compliance date for Division 4	§117.200(b)
SUBCHAPTER C: COMBUSTION CONTROL AT MAJOR UTILITY ELECTRIC GENERATION SOURCES IN OZONE NONATTAINMENT AREAS	
Division 4: Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources	§§117.1300 - 117.1356
- Exemption from Subchapter C, Division 2 after compliance date for Division 4	§117.1100(c)
SUBCHAPTER D: COMBUSTION CONTROL AT MINOR SOURCES IN OZONE NONATTAINMENT AREAS	
Division 2: Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources	§§117.2100 - 117.2145
SUBCHAPTER E: MULTI-REGION COMBUSTION CONTROL	
Division 2: Cement Kilns	§§117.3103, 117.3123, 117.3125, 117.3142, and 117.3145
Division 4: East Texas Combustion	§§117.3300 - 117.3345
SUBCHAPTER H: ADMINISTRATIVE PROVISIONS	
Division 1: Compliance Schedules	§§117.9030, 117.9130, 117.9210, 117.9320, and 117.9340

Implementation of HB 965 - Repeal of 10 ng/J standard on Type 0 (residential) water heaters.

SUBCHAPTER E: MULTI-REGION COMBUSTION CONTROL	
Division 3: Water Heaters, Small Boilers, and Process Heaters	§117.3205

Minor Changes to Existing 30 TAC Chapter 117 Language

• Add equation for oxygen correction of pollutant concentration.	§117.10(35)
• Update utility boiler definition and utility electric generation rules applicability consistent with East and Central Texas utility rules.	§§117.10(52), 117.1000, 117.1100, and 117.1200
• Update emergency fuel oil exemptions to include only appropriate reliability councils.	§§117.1003(c), 117.1103(c), and 117.1203(c)
• Include list of ammonia methods in test method procedures.	§117.8000(c)
• Allow major sources to petition ED for shorter test times.	§117.8000(b)
• Change references of "upsets" to "emissions events."	§§117.123(k), 117.223(k), 117.323(k), 117.1020(k), 117.1120(k), and 117.1220(k)
• Clarify system cap equations to allow for adjustment period after startup.	§117.320(c)
• Additional data substitution option for major sources subject to MECT.	§117.340(c)
• Expand engine low-use exemption from quarterly testing to BPA and DFW.	§117.8140(b)
• Update references to §101.222 to be consistent with current §101.222.	§§117.145(a), 117.245(a), 117.345(a), 117.1045(a), 117.1145(a), 117.1245(a), and 117.3045(a).
• Clarify compliance schedule for industrial EGFs to submit level of activity information.	§117.9020(2)(B)
• Allow Type 1 and 2 water heaters used exclusively for swimming pools and hot tubs at single family residences to qualify for exemption.	§117.3203(3)

Figure 2: 30 TAC Chapter 117--Preamble

Table 1

	5% IOP SIP April 27, 2005 TPD NO_X	TPD VOC
Adjusted Baseline Inventory	622.22	470.8
Percent Target Reduction	4.6	0.4
Target Reduction	28.62	1.88

Source of reductions	TPD NO_X	TPD VOC
Eligible existing measures		
Alcoa (within 200 km radius)	3.9	
TERP	22.2	
Energy efficiency	0.72	
Portable fuel containers (nine-county area)		2.79
Portable fuel containers (within 100 km radius)		0.63
Subtotal	26.82	3.42
Control measures requiring rulemaking		
Nine county lean-burn and rich-burn engine rule	1.87	
Expand surface coating rule to five counties		0.3
Lower Stage I exemption throughput to 10,000 gallons per month in five counties (same as in four core counties)		1.49
Subtotal	1.87	1.79
TOTAL IDENTIFIED REDUCTIONS	28.69	5.21
Minimum reductions required to meet 5%	28.69	1.86
SURPLUS REDUCTIONS	0.00	3.35

Figure: 30 TAC §117.10(35)

$$\text{Cadj} = \text{Cmeas} \times \frac{(20.9\% - \%O_2\text{rule})}{(20.9\% - \%O_2\text{meas})}$$

Where:

Cadj = pollutant concentration adjusted to percent O_2, dry basis, specified in applicable rule, in units of applicable standard (e.g., parts per million by volume);

Cmeas = pollutant concentration measured on a dry basis, in units of applicable standard;

20.9% = O_2 concentration in air, percent;

$\%O_2$ rule = O_2 basis for adjustment specified in applicable rule (e.g., 3.0% for boilers and process heaters) on a dry basis, percent; and

$\%O_2$ meas = O_2 concentration measured simultaneous with pollutant concentration, percent.

Figure: 30 TAC §117.105(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 NO_X emission limitation for each 30-day period, in lb/MMBtu of heat input;

EL_1 = appropriate NO_X emission specification for gas-fired boilers from paragraph (1)(A) - (F) of this subsection or gas-fired process heaters from paragraph (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.

Figure: 30 TAC §117.115(f)(4)

§117.115(f) OPT-IN UNITS

Equipment Class/Description	Emission Specification
fluid catalytic cracking unit carbon monoxide (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 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 §117.105(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 specification in §117.105(b) of this title

Figure: 30 TAC §117.115(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.

Figure: 30 TAC §117.115(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 grams per horsepower-hour;

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.

Figure: 30 TAC §117.115(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 NO_X in-stack concentration in parts per million by volume (ppmv);

A_{NOX} = the applicable NO_X emission specification of §117.105(c) of this title (expressed in ppmv NO_X 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.

Figure: 30 TAC §117.123(b)(1)

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

Where:

Cap_{30day} = the NO_X 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 = (A) for compliance with §117.105(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/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

(B) for compliance with §117.105(e) or §117.110 of this title. The actual historical average of the daily heat input for each unit included in the source cap, in MMBtu/day, as certified to the executive director, for a 24 consecutive month period between January 1, 1997, and December 31, 1999. 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 and United States Environmental Protection Agency may approve another method for calculating H_i. For sources complying with the lean-burn engine emission specifications in §117.105(e) of this title, the owner or operator may combine the source cap with sources complying with §117.105(a) – (d) of this title, using the 1997 - 1999 heat input baseline described earlier for the sources complying with §117.105(a) – (d) of this title; and

R_i = (A) for compliance with §117.105(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 implements 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 NO_X 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 §117.105(b) – (d) or §117.115(f) of this title or the best available control technology NO_X 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; and

(B) for compliance with §117.105(e) or §117.110 of this title, the lowest of:

(i) the appropriate specification of §§117.105(e), 117.110, or 117.115(f) of this title;

(ii) any permit NO_X emission 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, in effect on September 10, 1993; and

(iii) the actual emission rate as of the dates specified in clause (ii) of this figure. All calculations of emission rates must presume that emission controls in effect on the dates specified in clause (ii) of this figure are in effect for the two-year period used in calculating the actual heat input.

Figure: 30 TAC §117.123(b)(2)

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

Where:

Cap_{daily} = the NO_X maximum daily cap measured 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.

Figure: 30 TAC §117.205(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 NO_X emission limitation for each 30-day period, in lb/MMBtu of heat input;

EL_1 = appropriate NO_X emission specification for gas-fired boiler from §117.205(b)(1)(A) - (F) of this title or gas-fired process heaters from §117.205(b)(2)(A) - (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.

Figure: 30 TAC §117.215(f)(4)

§117.215(f) OPT-IN UNITS

Equipment Class/Description	Emission Specification
fluid catalytic cracking unit carbon monoxide (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) ≤MRC< 100 MMBtu/hr	the emission specifications in §117.205(a) of this title for the applicable type of unit
stationary gas turbines with a megawatt (MW) rating: 1.0 MW ≤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 specification in §117.205(b) of this title

Figure: 30 TAC §117.215(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.

Figure: 30 TAC §117.215(g)(2)

$$\mathrm{EL}_{\mathrm{PW}} = \frac{\mathrm{MRC} \times \mathrm{ES}}{HR \times \left(454 \times 10^{6}\right)}$$

Where:

$\mathrm{EL}_{\mathrm{PW}}$ = 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.

Figure: 30 TAC §117.215(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 NO_X in-stack concentration in ppmv;

A_{NOX} = the applicable NO_X emission specification of §117.205(c) of this title (expressed in ppmv NO_X 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.

Figure: 30 TAC §117.223(b)(1)

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

Where:

Cap_{30day} = the NO_X 30-day rolling average emission cap measured 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 = (A) for compliance with §117.205(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/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

(B) for compliance with §117.210 of this title. The actual historical average of the daily heat input for each unit included in the source cap, in MMBtu/day, as certified to the executive director, for a 24 consecutive month period between January 1, 1997, and December 31, 1999. 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 and the United States Environmental Protection Agency may approve another method for calculating H_i; and

R_i = (A) for compliance with §117.205(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 implements 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 NO_X 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 §117.205(b) – (d) or §117.215(f) of this title or the best available control technology NO_X 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; and

(B) for compliance with §117.210 of this title, the lowest of:

(i) the appropriate limit of §117.210 or §117.215(f) of this title;

(ii) any permit NO_X emission 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, in effect on September 1, 1997; and

(iii) the actual emission rate as of the dates specified in clause (ii) of this subparagraph. All calculations of emission rates must presume that emission controls in effect on the dates specified in clause (ii) of this subparagraph are in effect for the two-year period used in calculating the actual heat input.

Figure: 30 TAC §117.223(b)(2)

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

Where:

Cap_{daily} = the NO_X maximum daily cap measured 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.

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 NO_X emission limitation for each 30-day period, in lb/MMBtu of heat input;

EL_1 = appropriate NO_X 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.

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

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.

Figure: 30 TAC §117.315(g)(2)

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

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.

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 NO_X in-stack concentration in ppmv;

A_{NOX} = the applicable NO_X emission specification of §117.305(c) of this title (expressed in ppmv NO_X 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.

Figure: 30 TAC §117.320(c)(1)

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

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.

Figure: 30 TAC §117.320(c)(2)

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

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. 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.

Figure: 30 TAC §117.320(c)(3)

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

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.

Figure: 30 TAC §117.323(b)(1)

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

Where:

Cap_{30day} = the NO_X 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 NO_X 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.

Figure: 30 TAC §117.323(b)(2)

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

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 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.

Figure: 30 TAC §117.423(b)(1)

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

Where:

Cap_{30day} = the NO_X 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 = the actual historical average of the daily heat input for each unit included in the source cap, in million British thermal units per day, as certified to the executive director, for a 24 consecutive month period between January 1, 2000, and December 31, 2001. 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 and the United States Environmental Protection Agency may approve another method for calculating H_i; and

R_i = the lowest of:

(i) the appropriate specification of §117.410 of this title;

(ii) any permit NO_X emission limit for any unit subject to a permit issued in accordance with Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification), in pounds per million British thermal units (lb/MMBtu), that applies to emission unit I in the absence of trading, in the Dallas-Fort Worth eight-hour ozone nonattainment area, in effect on December 31, 2000; and

(iii) the actual emission rate as of the dates specified in clause (ii) of this figure. All calculations of emission rates must presume that emission controls in effect on the dates specified in clause (ii) of this figure are in effect for the two-year period used in calculating the actual heat input.

Figure: 30 TAC §117.423(b)(2)

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

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 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.

Figure: 30 TAC §117.423(b)(4)

$$\mathrm{Cap}_{\mathrm{ICE}} = \frac{\mathrm{MRC} \times \mathrm{ES}}{HR \times \left(454 \times 10^6\right)}$$

Where:

Cap_{ICE} = source cap allowable emission rate in pounds per hour;

ES = emission specification in grams per horsepower-hour (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 (hp) rating, in British thermal units per horsepower-hour.

Figure: 30 TAC §117.423(b)(5)

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

$$\text{Cap}_{GT} = C_{instack} \times MF \times \left(\frac{46}{28} \times 10^{-6}\right)$$

Where:

$C_{instack}$ = the NO_X in-stack concentration in parts per million by volume (ppmv);

A_{NOX} = the applicable NO_X emission specification of §117.410(b) of this title (expressed in ppmv NO_X at 15% oxygen (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;

Cap_{GT} = source cap allowable emission rate 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.

Figure: 30 TAC §117.1005(d)

$$EL = \frac{(0.26a + 0.30b)}{(a + b)}$$

Where:

EL = emission specification (heat input weighted average) on a rolling 24-hour average basis;

a = the percentage of total heat input from natural gas; and

b = the percentage of total heat input from fuel oil.

Figure: 30 TAC §117.1015(d)(1)

$$EL_{SW} = R \times ES$$

Where:

EL_{SW} = system-wide emission specification in pounds per hour;

ES = emission specification in lb/MMBtu; and

R = average activity level for fuel oil firing or maximum rated capacity for gas firing, in million British thermal units per hour (MMBtu/hr).

Figure: 30 TAC §117.1015(d)(2)

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

$$EL_{SW} = C_{instack} \times MF \times \left(\frac{46}{28} \times 10^{-6}\right)$$

Where:

$C_{instack}$ = the NO_X in-stack concentration in parts per million by volume (ppmv);

A_{NOX} = the applicable NO_X emission specification of §117.1005(f) or (g) of this title, in ppmv NO_X at 15% oxygen (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_{SW} = system-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.

Figure: 30 TAC §117.1020(c)(1)

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

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 = the average of the daily heat input for each EGF in the emission cap, in million British thermal units per day, as certified to the executive director, for the system highest 30-day period in the nine months of July, August, and September 1996, 1997, and 1998. 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 1996 - 1998 may be used; and

R_i = the emission specification of §117.1010(a) of this title.

Figure: 30 TAC §117.1020(c)(2)

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

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 daily 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.

Figure: 30 TAC §117.1105(d)

$$EL = \frac{(0.26a + 0.30b)}{(a + b)}$$

Where:

EL = emission specification (heat input weighted average) on a rolling 24-hour average basis;

a = the percentage of total heat input from natural gas; and

b = the percentage of total heat input from fuel oil.

Figure: 30 TAC §117.1115(d)(1)

$$EL_{SW} = R \times ES$$

Where:

EL_{SW} = system-wide emission specification in pounds per hour;

ES = emission specification in pounds per million British thermal units (lb/MMBtu); and

R = average activity level for fuel oil firing or maximum rated capacity for gas firing, in million British thermal units per hour (MMBtu/hr).

Figure: 30 TAC §117.1115(d)(2)

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

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

Where:

$C_{instack}$ = the NO_X in-stack concentration in parts per million by volume (ppmv);

A_{NOX} = the applicable NO_X emission specification of §117.1105(f) or (g) of this title, in ppmv NO_X at 15% oxygen (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_{SW} = system-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.

Figure: 30 TAC §117.1120(c)(1)

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

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 = the average of the daily heat input for each EGF in the emission cap, in million British thermal units per day, as certified to the executive director, for the system highest 30-day period in the nine months of July, August, and September 1996, 1997, and 1998. 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 1996 - 1998 may be used; and

R_i = the emission specification of §117.1110(a) of this title.

Figure: 30 TAC §117.1120(c)(2)

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

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 daily 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.

Figure: 30 TAC §117.1205(d)

$$EL = \frac{(0.26a + 0.30b)}{(a + b)}$$

Where:

EL = emission specification (heat input weighted average) on a rolling 24-hour average basis;

a = the percentage of total heat input from natural gas; and

b = the percentage of total heat input from fuel oil.

Figure: 30 TAC §117.1215(d)(1)

$$EL_{SW} = R \times ES$$

Where:

EL_{SW} = system-wide emission specification in pounds per hour;

ES = emission specification in lb/MMBtu; and

R = average activity level for fuel oil firing or maximum rated capacity for gas firing, in million British thermal units per hour (MMBtu/hr).

Figure: 30 TAC §117.1215(d)(2)

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

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

Where:

$C_{instack}$ = the NO_X in-stack concentration in parts per million by volume (ppmv);

A_{NOX} = the applicable NO_X emission specification of §117.1205(f) or (g) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), in ppmv NO_X at 15% oxygen (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_{SW} = system-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.

Figure: 30 TAC §117.1220(c)(1)

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

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, as certified to the executive director, for any system 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 any system 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, 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 has 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 (relating to Definitions); 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, variables

(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, variables (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 §117.1210(a) of this title.

Figure: 30 TAC §117.1220(c)(2)

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

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 daily 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.

Figure: 30 TAC §117.1310(a)(2)(C)

$$EL = \frac{(0.26a + 0.30b)}{(a + b)}$$

Where:

EL = emission specification (heat input weighted average) on a rolling 24-hour average basis;

a = the percentage of total heat input from natural gas; and

b = the percentage of total heat input from fuel oil; and

Figure: 30 TAC §117.3020(c)

$$Cap_{annual} = \sum_{i=1}^{N} \frac{(H_i \times R_i)}{2000}$$

Where:

Cap_{annual} = the NO_X annual average emission cap in tons per year;

i = each unit in the electric power generating system;

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

H_i = the average of the annual heat input for each unit in the emission cap, in million British thermal units per year, as certified to the executive director, for 1996, 1997, and 1998; and

R_i = the emission specification of §117.3010 of this title.

Figure: 30 TAC §117.3120(a)

$$\text{Cap} = 0.7\sum_{i=1}^{N} R_i$$

Where:

Cap = 90-day rolling average NO_X emission cap, in ppd;

i = each cement kiln at a single account;

N = the total number of cement kilns at the account; and

R_i = the kiln's ozone season daily NO_X emission rate (in ppd) reported in the account's 1996 EI.

Figure: 30 TAC §117.3123(b)

$$\text{Cap}_{8hour} = (N_W \times K_W) + (N_D \times K_D)$$

Where:

Cap_{8hour} = total allowable NO_X emissions from all cement kilns located at an account, tons per day, 30-day rolling average basis;

K_D = 2.84 tons per day of NO_X emissions for dry preheater-precalciner or precalciner kilns;

K_W = 1.39 tons per day of NO_X emissions for long wet kilns;

N_D = the total number of dry preheater-precalciner or precalciner kilns located at the account and operational during calendar year 2000; and

N_W = the total number of long wet kilns located at the account and operational during calendar year 2000.

Figure: 30 TAC §117.3142(b)(1)

$$EH = C \times F \times K \times \frac{60\text{min}}{\text{hour}}$$

Where:

EH = total hourly NO_X emissions from each kiln located at the account, in pounds per hour;

C = the block hour average NO_X concentration, determined in accordance with subsection (a)(1) of this section, in parts per million by volume (ppmv), dry basis, corrected to 7% oxygen (O_2);

F = the block average exhaust flow rate, determined in accordance with subsection (a)(2) of this section, in dry standard cubic feet per minute, corrected to 7% O_2; and

K = conversion factor, 1.194×10^{-7} pounds per standard cubic foot per ppmv (40 CFR Part 60, Appendix A, Method 19, Table 19-1).

Figure: 30 TAC §117.3142(b)(2)

$$ED = \frac{\sum_{i=1}^{N} EH_i}{2000}$$

Where:

ED = total daily NO_X emissions from each kiln located at the account, in tons per day;

EH = total hourly NO_X emissions from each kiln located at the account, in pounds per hour calculated according to the equation in subsection (b)(1) of this section; and

N = number of hours of operation per day for each kiln located at the account, in hours.

Figure: 30 TAC §117.3142(b)(3)

$$E_{30day} = \frac{\sum_{i=1}^{K}\sum_{j=1}^{N} ED_{i,j}}{N}$$

Where:

E_{30day} = rolling 30-day average NO_X emissions in tons per day for the account, computed for the preceding 30 days;

ED = total daily NO_X emissions from each kiln located at the account, in tons per day, calculated according to the equation in subsection (b)(2) of this section;

K = number of kilns located at the account; and

N = preceding 30 days.

Figure: 30 TAC §117.8130(1)

$$NH_3 @ O_2 = \left[\left(\frac{a}{b} \times 10^6\right) - c\right] \times d$$

Where:

$NH_3@O_2$ = ammonia parts per million by volume (ppmv) at reference oxygen. Reference oxygen on a dry basis is 3.0% for boilers and process heaters; 0.0% for fluid catalytic cracking units (including carbon monoxide (CO) boilers, CO furnaces, and catalyst regenerator vents); 7.0% for boilers and industrial furnaces that were regulated as existing facilities by the United States Environmental Protection Agency 40 Code of Federal Regulations Part 266, Subpart H (as was in effect on June 9, 1993), wood-fired boilers, and incinerators; 15% for stationary gas turbines (including duct burners used in turbine exhaust ducts), gas-fired lean-burn engines, and lightweight aggregate kilns; and 3.0% for all other units;

a = ammonia injection rate (in pounds per hour (lb/hr))/17 pound per pound-mole (lb/lb-mol);

b = dry exhaust flow rate (lb/hr)/29 lb/lb-mol;

c = change in measured NO_X concentration across catalyst (ppmv at reference oxygen); and

d = correction factor, the ratio of measured slip to calculated ammonia slip, where the measured slip is obtained from the stack sampling for ammonia during an initial demonstration of compliance required by this chapter and using the methods specified in §117.8000 of this title (relating to Stack Testing Requirements).

Figure: 30 TAC §117.9800(d)

$$\Delta E = \left[LA \times \left(ER_{old} - ER_{new} \right) \times \frac{d}{2000} \right]$$

Where:

ΔE = the differential of emissions;

LA = the maximum level of activity;

ER_{old} = the existing NO_X emission rate for the affected unit in pounds per unit of activity;

ER_{new} = the new NO_X emission rate for the affected unit in pounds per unit of activity; and

d = (A) to calculate annual emission reductions, d = 365; and

(B) to calculate emission reductions for the remainder of a control period, d = the number of days remaining in the control period.