The Texas Commission on Environmental Quality (TCEQ or commission) proposes amendments to §§117.114, 117.201, 117.203, 117.206, 117.213, 117.214, 117.479, and 117.520.

These amended sections and corresponding revisions to the state implementation plan (SIP) will be submitted to the United States Environmental Protection Agency (EPA).

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE PROPOSED RULES

The Federal Clean Air Act (FCAA) Amendments of 1990 as codified in 42 United States Code (USC), §§7401 *et seq*. require EPA to set national ambient air quality standards (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 NAAQS once the EPA has established them. 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, in accordance with the 1990 FCAA Amendments, and 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 a new SIP demonstrating attainment by the new deadline of November 15, 1999.

The Dallas/Fort Worth area also failed to reach attainment by the November 1999 deadline. In the attainment demonstration SIP 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 (HGB area) were considered. Based on photochemical modeling demonstrating transport from the HGB 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 HGB 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 overturned by federal courts, which ruled that EPA does 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. Thus, the Dallas/Fort Worth area does not currently have an approved attainment demonstration SIP for the one-hour ozone NAAQS.

On July 18, 1997, EPA promulgated a revised ozone standard (the eight-hour ozone NAAQS), and on April 30, 2004, promulgated the first phase implementation rule 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 (DFW area). The DFW area consists of nine counties

(Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant) effective June 15, 2004, for the eight-hour ozone NAAQS. The DFW area must attain the eight-hour ozone NAAQS by June 15, 2010.

EPA's Phase I guidance 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 no later than one year after the effective date of the designation (by June 15, 2005); 2) submit an eight-hour ozone plan no later than one year after the effective date of the designation (by June 15, 2005) that provides a 5% increment of reductions from the area's 2002 emissions baseline that is in addition to federal measures and state measures already approved by EPA, and to achieve these reductions by June 15, 2007; or 3) submit an eight-hour ozone attainment demonstration by June 15, 2005. Options one and three require successful photochemical grid modeling performance. Based on poor model performance, the commission, in coordination with EPA, determined that option two is the most expeditious approach to beginning to achieve the reductions ultimately needed to: 1) meet the June 15, 2005, transportation conformity deadline; and 2) attain the eight-hour ozone NAAQS by June 15, 2010. In order for the DFW area to comply with the requirement to submit a 5% increment of progress plan that provides a 5% emission reduction from the 2002 emissions baseline, additional emission reduction strategies are necessary.

The proposed 5% increment of progress plan would include implementing new emission specifications and other requirements for certain industrial, commercial, and institutional stationary internal combustion engines in Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties to reduce NO_x emissions and ozone air pollution.

The emission reduction requirements that will result from this proposed rulemaking, if adopted, will result in reductions in ozone formation in the DFW area and help bring the DFW area into compliance with the eight-hour ozone NAAQS. These emission reductions are one component of the Dallas/Fort Worth SIP that the state is required to submit to EPA to assure attainment and maintenance of the eight-hour ozone NAAQS. Attainment of the eight-hour ozone standard may require further reductions in NO_x emissions as well as VOC emissions. This rulemaking is one step toward meeting the state's obligations under the FCAA. EPA has not yet issued Phase II of its eight-hour implementation rule (Phase II guidance) for states to use in developing eight-hour ozone attainment demonstrations. Phase II guidance is expected to be promulgated by EPA in the fall of 2004, which will provide additional information relating to eight-hour ozone attainment demonstrations. The commission is continuing to prepare for the required eight-hour ozone attainment demonstration SIP.

In addition to the changes applicable to certain engines in the DFW area, the commission is proposing technical changes to improve the language to best state the commission’s intent regarding current requirements for major and minor sources of NO_x emissions in ozone nonattainment areas. Each proposed change would affect one or more of the ozone nonattainment areas of the state. The ozone nonattainment areas are Beaumont/Port Arthur ozone nonattainment area (BPA area), DFW area, and HGB area. The commission is also proposing to correct references and typographical errors as required by Texas Register formatting requirements.

SECTION BY SECTION DISCUSSION

The commission is only soliciting comments on the language that is amended by this rulemaking. The commission is not seeking comment on nor does it intend to make changes to any rule language that is not being amended by this proposed rulemaking.

Subchapter B, Combustion at Major Sources

Division 1, Utility Electric Generation in Ozone Nonattainment Areas

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

The commission proposes to amend §117.114(a)(4)(A) to correct the mass balance equation to show that the variable for the correction factor "d" multiplies the result of the operations of the other variables. The subparagraph containing the equation and associated variables would be reformatted for readability. The proposed amendments would also revise §117.114(a)(4)(A) to specify that minor changes to the required test methods or EPA-approved alternative test methods may be approved by the executive director for the testing required to determine the correction factor "d." The commission proposes to remove language in §117.114(a)(4)(D) that states that for this subparagraph the Engineering Services Team acts for the executive director.

Division 3, Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas

§117.201. Applicability.

The commission proposes to add the phrase "or as otherwise specified" after the listing of ozone nonattainment areas. This addition is needed to alert potentially affected persons that other sections within this division may contain additional applicability requirements. In the case of this proposed rule package, persons in Ellis, Johnson, Kaufman, Parker, and Rockwall Counties, potentially could be subject to control requirements found in §117.206, even though these counties are not listed in the current definition of "Dallas/Fort Worth (DFW) ozone nonattainment area" found in §117.10.

§117.203. Exemptions

The commission proposes to remove an extraneous "and" from §117.203(a)(11)(B) and add "and" to §117.203(a)(12)(B).

The commission also proposes to add, in new §117.203(a)(13), an exemption for cogeneration boilers that recover waste heat from one or more carbon black reactors for sources in the BPA area, except as may be specified in 30 TAC §§117.206(i), 117.209(c)(1), 117.213(i), 117.214(a)(2), 117.216(a)(5), and 117.219(f)(6) and (10). This exemption is added because the commission has not historically relied on nor is now relying on reductions from these cogeneration boilers to demonstrate compliance with the one-hour and eight-hour ozone NAAQS.

New §117.203(c) will remove the exemption in §117.203(a)(1) for the engines specified in the emission specifications in §117.206(b)(3). The exemption in subsection (a)(1) no longer applies after June 15, 2007, which is the compliance date for the 5% increment of progress SIP revision in the DFW area. This assures that all gas-fired lean-burn and gas-fired rich-burn engines, that are greater than or equal to 300 horsepower (hp), in the affected counties will be required to meet the new emission specifications in §117.206(b)(3) regardless of when the units were placed into service.

Under 42 USC, §7511a(f), any moderate, serious, severe, or extreme ozone nonattainment area was required to implement NO_x reasonably available control technology (RACT) unless a demonstration was made that NO_x reductions would not contribute to, or would not be necessary for, attainment of the ozone standard. The exemption in §117.203(a)(1) for units placed into service after November 15, 1992 was part of the initial NO_x RACT rules adopted on May 11, 1993. This exemption included the November 15, 1992, date because this was the FCAA deadline by which states were to promulgate NO_x RACT rules. The pollution controls in new source review permits issued after November 15, 1992, were expected to represent RACT, while the pollution controls in the permits issued before November 15, 1992, do not necessarily represent RACT because these permits were required to represent best available control technology (BACT) which evolves and becomes more stringent over time.

Section 117.203(a)(1) was included in the Dallas/Fort Worth SIP to exclude new sources placed into service after the effective date of nonattainment new source review, November 15, 1992, from the emission standards in Chapter 117. Under these rules, major net increases by new or modified major stationary sources must apply controls representing the lowest achievable emission rate (LAER) and obtain emission offsets in order to construct and operate. The DFW area is now designated nonattainment for the eight-hour NAAQS. Additional emission reductions from previously-exempted units and from additional source categories are necessary to achieve the reductions for the 5% increment of progress SIP revision.

§117.206. Emission Specifications for Attainment Demonstrations

The commission proposes to amend §117.206(b) to remove the words "in the Dallas/Fort Worth ozone nonattainment area" because the commission also proposes that each paragraph in this subsection specify the particular counties in which emission limitations apply, and the particular compliance schedule for each paragraph.

Amended §117.206(b) (1) states that gas-fired boilers in Collin, Dallas, Denton, and Tarrant Counties must comply with the existing NO_x emission limitations according to the compliance schedule in §117.520(b)(1). The commission proposes to amend §117.206(b)(2) to change "gas/liquid-fired" to "dual-fuel" to be consistent with references to types of engines in other sections of Chapter 117. Amended §117.206(b)(2) states that gas-fired and dual-fuel boilers in Collin, Dallas, Denton, and Tarrant Counties must comply with the existing NO_x emission limitations according to the compliance schedule in §117.520(b)(1).

Proposed new §117.206(b)(3) would establish a new emission specification for gas-fired lean-burn, and gas-fired rich-burn stationary reciprocating internal combustion engines in Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties. Amended §117.206(b)(3) also specifies that the engines in these counties must comply with the emission standard in accordance with the compliance schedule in §117.520(b)(2). Reductions from these units will be applied to the 5% increment of progress SIP revision. The proposed emission specification is 0.5 grams per horsepower hour (g/hp-hr) for both lean-burn internal combustion engines and rich-burn internal combustion engines. The proposed emission specifications would affect a total of 13 lean-burn engines and six rich-burn engines at four sources in Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties.

All six of the affected rich-burn engines in the 2002 TCEQ emissions inventory are located in Ellis, Johnson, Kaufman, Parker, and Rockwall Counties. These units would be able to obtain the 0.5 g/hp-hr limit through either application of non-selective catalytic reduction or application of non-selective catalytic reduction combined with an additional catalyst module. All rich-burn engines in Collin, Dallas, Denton, and Tarrant Counties were required to meet the existing emission specification of 2.0 g/hp-hr by March 31, 2002. The TCEQ 2002 emissions inventory does not include any rich-burn engines in Collin, Dallas, Denton, and Tarrant Counties, so it is unknown what impact the proposed 0.5 g/hp-hr emission standard would have on reduction of NO_x emissions for rich-burn engines in these counties. It is, however, anticipated that any rich-burn engines that are located in these counties, but were not included in the emissions inventory, could use either the application of non-selective catalytic reduction or application of non-selective catalytic reduction combined with an additional catalyst module to achieve the proposed 0.5 g/hp-hr limit.

The 2002 TCEQ emissions inventory shows that there are 13 affected lean-burn engines in the DFW area. These engines would be required to implement an exhaust gas recirculation kit (in order to reduce the excess oxygen) and non-selective catalytic reduction to meet the proposed 0.5 g/hp-hr emission limit.

Both lean-burn and rich-burn engines would also be required to perform a stack test in accordance with 30 TAC §117.211.

The proposed amendment to §117.206(b) specifies the various compliance schedules for these engine categories.

The commission proposes to add language in §117.206(h)(1), which would clarify that the maximum rated capacity of units subject to §117.206(c) should be used to determine requirements for control plans, compliance demonstration, monitoring, testing requirements, and final control plan. This will ensure that the prohibition of circumvention provisions of subsection (h)(1) establish maximum rated capacity for the emission specifications in subsection (c) as well as any control plans, compliance, monitoring, and testing requirement in §§117.209, 117.211, 117.213, 117.214, and 117.216. This amendment would apply in the HGB area as the provisions in §117.206(h)(1) are applicable only to HGB area sources.

The commission is seeking comment specifically regarding the proposed changes to §117.206(b) and (h). The commission is not seeking comment on, nor does it intend to make changes to, any other subsections of this section.

§117.213. Continuous Demonstration of Compliance

The commission proposes to add language to §117.213(a) that would specify the accuracy of totalizing fuel flow meters to ± 5%. Language added to this subsection would also allow the amount of fuel burned in pilot flames to be calculated based on the manufacturer's design flow rates instead of requiring a separate fuel flow meter to measure the amount of fuel burned. This amendment would require that the calculated result be added to the metered value for total fuel use. This amendment would apply in the BPA area, DFW area, and HGB area because all three areas have fuel flow requirements.

The commission proposes to clarify the totalizing fuel flow requirements for wood-fired boilers in the HGB area by revising §117.213(a)(1)(B)(i). The commission requires a mechanism to measure activity or throughput for wood-fired boilers, however, a totalizing fuel flow meter can only be used to measure gas or liquid fuel. The proposed revision would require maintaining records of fuel usage as required in §117.219(f) or monitoring exhaust flow. This revision would only apply in the HGB area as there are currently no wood-fired boiler requirements in the BPA area or DFW area.

The commission proposes to add language to §117.213(a)(1)(B)(xiii) that would exempt dilute vapor streams resulting from vessel cleaning and routed to an incinerator from the fuel flow meter requirements. These streams are of uneven heat content so measurement by a fuel flow meter would not be an accurate indicator of fuel use. This amendment specifies that emissions resulting from the combustion of dilute vapor streams must be calculated using good engineering methods. This would only apply in the HGB area. There are currently no fuel flow requirements for incinerators in the BPA area or DFW area.

The commission proposes to restructure §117.213(a)(2) by adding new subparagraph (B) that would allow a single totalizing fuel flow meter to monitor flow to multiple units as long as the units exhaust to a common stack monitored with a continuous emissions monitoring system (CEMS). The proposed changes would also add new §117.213(a)(2)(C) that would allow a fuel flow alternative for stationary diesel internal combustion engines. As long as the diesel engine is equipped with a run time meter, the use of monthly fuel use records is sufficient to measure activity or throughput. These amendments would apply to the BPA area, DFW area, and HGB area.

The commission proposes to amend §117.213(b)(3) to replace the word "necessitated" with "required."

The commission proposes to add new paragraph (3) to §117.213(c) to provide for collection of substitute emissions compliance data in the event that the NO_x CEMS or predictive emission monitoring system (PEMS) is off-line. In this event, the owner or operator of the unit would be required to comply with the missing data procedures in 40 Code of Federal Regulations (CFR) Part 75 as well as in §117.213. This amendment would apply in the BPA area, DFW area, and HGB area.

The commission proposes to amend §117.213(e)(2) to correct a typographical error in the term "O_2."

The commission proposes to amend §117.213(e)(3) to clarify that all exhaust stacks, from a unit for which a CEMS is required, must be monitored using a single monitor per stack or a time-shared monitor that can analyze each stack individually. This amendment would apply in the BPA area, DFW area, and HGB area.

The commission proposes to add new language to §117.213(e)(4)(A) that would allow bypass stacks to be monitored upstream of the stack provided no additional NO_x gas streams are introduced downstream of the monitor. The commission proposes this amendment because, depending on the unit, installing a CEMS in the bypass stack itself may require that the unit be forced into upset in order to perform initial certification of the CEMS. The amendment requires that accurate readings be maintained and bypass stacks be continuously monitored to determine when the stack is in operation. The commission is retaining the option that currently exists in the rule allowing latitude in monitor placement, but this amendment will ensure that no additional contaminants are introduced into the exhaust where they cannot be monitored. In addition, the commission proposes changes to clarify that process knowledge and engineering calculations may be used to determine volumetric flow rate for the purposes of quantifying mass emissions for each event when the bypass stack is open. The proposed language would require that the maximum potential calculated flow rate be used and that the owner or operator maintain records on all process information and calculations and make these records available upon request by the executive director. An amendment to §117.213(e)(4)(B) allows CEMS to be shared among multiple exhaust stacks on a single unit provided certain conditions are met. A change to §117.213(e)(4)(C) adds an "and" to accommodate new §117.213(e)(4)(D) that specifies that each individual stack must be analyzed separately for units with multiple exhaust stacks. The revisions to §117.213(e)(4) would apply in the HGB area.

The commission proposes to amend §117.213(f)(5)(A)(ii)(VI) to replace "Engineering Services Team" with "executive director."

The commission is only seeking comment regarding the proposed changes to §117.213(a), (c)(3), and (e)(3) and (4). The commission is not soliciting comments on the applicability of meter and monitoring requirements for units except for wood-fired boilers.

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

The commission proposes to amend §117.214(a)(1)(D)(i) to correct the mass balance equation to show that the variable for the correction factor "d" multiplies the result of the operations of the other variables. The clause containing the equation would be reformatted for readability. The proposed amendments would also revise §117.214(a)(1)(D)(i) to specify that minor changes to the required test methods or EPA-approved alternative test methods may be approved by the executive director for the testing required to determine the correction factor "d." Also, §117.214(a)(1)(D)(iv) would be amended to remove language stating that the Engineering Services Team acts for the executive director in approving alternate monitoring methods for ammonia.

The commission proposes to restructure §117.214(b)(2) by adding new paragraph (2), which clarifies that the provisions in the rule require testing for stationary internal combustion engines in accordance with §117.213(g)(1), concerning Continuous Demonstration of Compliance.

Subchapter D, Small Combustion Sources

Division 2, Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources

§117.479, Monitoring, Recordkeeping, and Reporting Requirements

The amendments to §117.479 would apply in the HGB area only because this division only applies to the HGB area.

The commission proposes to add language to §117.479(a) that specifies the accuracy of totalizing fuel flow meters to an accuracy of ± 5%. Language added to this subsection would also allow 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.

The commission also proposes to add language to exempt units from the totalizing fuel flow meter requirements if the site is not subject to the mass emissions cap and trade (MECT) program in 30 TAC Chapter 101, Subchapter H, Division 3. For the purposes of this division, fuel metering is not required unless the unit is subject to the MECT program or the owner or operator is claiming that the unit is exempt from the emission specifications in 30 TAC §117.475 due to low heat input as specified in 30 TAC §117.473(b). Totalizing fuel flow meters should only be required for units that must demonstrate continuous compliance with the MECT program and the heat input limits in §117.473(b).

The commission proposes to add new §117.479(a)(2)(B) that would allow a single totalizing fuel flow meter to monitor flow to multiple units as long as the units exhaust to a common stack monitored with a CEMS. The proposed changes would also add new §117.479(a)(2)(C) that would allow a fuel flow alternative for stationary diesel internal combustion engines. If the diesel engine is equipped with a run time meter, the use of monthly fuel use records is sufficient to meet fuel flow monitoring requirements.

The commission proposes to provide an alternative to the totalizing fuel flow meter requirements in new §117.479(a)(2)(D) for units subject to the MECT program by allowing meter sharing among units. This alternative would be an option for owners or operators who perform a stack test on all units sharing a totalizing fuel flow meter in accordance with §117.479(e). The owner or operator would also be required to use the emission rate from the stack test with the highest emission rate to quantify the emissions for purposes of MECT reporting in accordance with 30 TAC §101.359. This alternative in §117.479(a)(2)(D) is proposed to minimize economic impact for minor sources. This division applies only to minor sources. It is important to note that although units that are not subject to the MECT program would not be required to have a totalizing fuel flow meter, the owner or operator of each unit claiming the exemption in §117.473(b) would still be subject to the annual fuel usage recordkeeping requirements in §117.479(g)(1).

The commission proposes to amend 117.479(e)(3) to allow shorter test times provided that they are approved by the executive director. This change ensures that the executive director has sufficient flexibility to address issues that may result from affected units that only operate for short periods of time in a day.

Subchapter E, Administrative Provisions

§117.520. Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas

The commission proposes to restructure §117.520(b) in order to accommodate the following changes. Proposed amended §117.520(b)(1) restates the current compliance schedule that applies to DFW area sources, noting an exception for new §117.520(b)(2). Proposed new §117.520(b)(2) specifies the June 15, 2007 compliance date for the proposed emissions specifications, monitoring, testing requirements, and final control plans for certain internal combustion engines in the DFW area. The compliance date of June 15, 2007 is established to meet the EPA requirements in 40 CFR §51.905 relating to the 5% increment of progress. The amendment also specifies that all sources must submit the first semiannual report by January 31, 2008. Reference to these compliance dates are set forth for the proposed DFW area engine emission specifications in §117.206(b)(3).

The commission also proposes to correct a rule reference in §117.520(c)(1)(A)(iii).

The commission proposes to amend §117.520(c)(2)(A)(ii) to provide that compliance with the requirements of §117.214 is required not later than 60 days after startup of a unit following installation of emission monitors, not just following installation of emission controls. This allows owners or operators 60 days after startup of a unit following installation of emissions controls to comply with the provisions in §117.214 as well as providing 60 days following the installation of emissions monitors. Therefore, the commission is proposing to amend §117.520(c)(2)(A)(ii) to state these compliance dates more precisely. This clarification relates to compliance dates in the HGB area only.

Units subject to 30 TAC §117.210, concerning System Cap, and not in operation prior to January 1, 1997, have the option of choosing any two consecutive years out of five for the average daily heat input (H_i) level of activity (LOA) certification requirements. The compliance dates in §117.520(c)(2)(B)(ii) specify that the certification of LOA shall be submitted no later than 60 days after the second consecutive third quarter of actual LOA is complete. This does not allow companies to choose any two out of five years before certifying the LOA. The commission is proposing to add language in subsection (c)(2)(B)(ii) to allow owners or operators 60 days after the second consecutive third quarter of actual LOA out of the first five years of operation is chosen to submit their LOA.

The commission is proposing new §117.520(c)(2)(G) to provide owners or operators of units that will be shutting down within 60 days of the compliance date, May 31, 2005, relief from the monitoring requirements in §117.214(a). Specifically, an owner or operator would have to submit written notification to the executive director no later than March 31, 2005, containing the following information: a list of units, by emission point number, that the owner or operator intends to shut down on or before May 31, 2005; the projected date each unit will be shut down; and the projected dates of the stack testing. The owner or operator would also be required to perform a stack test in accordance with §117.211 after March 31, 2005, and prior to May 31, 2005. For the time period from March 31, 2005, and May 31, 2005, the results of this testing shall be used for demonstrating compliance with the emission specifications in §117.206(c) or to quantify the emissions for units subject to the MECT program. The proposed revision would also require owners or operators that have not installed totalizing fuel flow meters to use the maximum rated capacity of the unit to quantify the emissions between March 31, 2005, and May 31, 2005. The revision also specifies that if the unit is not shut down by May 31, 2005, the owner or operator will be considered in violation of §117.520(c) as of March 31, 2005 and that extensions beyond May 31, 2005 will not be granted.

FISCAL NOTE: COSTS TO STATE AND LOCAL GOVERNMENT

Jeffrey Horvath, Analyst, Strategic Planning and Grants Management Section, determined that for the first five-year period the proposed rules are in effect, no significant fiscal implications are anticipated for the agency and no fiscal implications are anticipated for other units of state or local government because none of the affected engines are owned or operated by units of local government. Fiscal implications are anticipated for certain owners and operators of industrial, commercial, and institutional stationary internal combustion engines in the DFW area.

The amendments are proposed in order to begin to achieve reductions ultimately needed for attainment of the eight-hour ozone NAAQS. In order for the DFW area to comply with the requirement to submit a 5% increment of progress plan that provides a 5% emission reduction from the 2002 emissions baseline, additional emission reduction strategies are necessary.

The proposed amendments would establish new emission specifications for gas-fired lean-burn and rich-burn stationary reciprocating internal combustion engines in Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties. Reductions from these units will be applied to the 5% increment of progress SIP revision.

The proposed amendments also provide alternate monitoring and fuel flow metering requirements for major and minor emission sources in the BPA area, DFW area, and HGB area. These alternatives are expected to provide flexibility to owners and operators in how they monitor their emissions and meter fuel flow. This flexibility may result in cost savings for some individual sources. However, any efficiencies that are realized would depend upon specific circumstances at a particular site and the options used by that particular site for monitoring or metering activities.

The proposed rules are expected to result in the need for the agency to conduct additional compliance inspections in the DFW area, though any increase in workload is anticipated to be absorbed using existing resources.

PUBLIC BENEFITS AND COSTS

Mr. Horvath also determined that for each year of the first five years the proposed rules are in effect, the public benefit anticipated from the changes seen in the proposed rules will be reductions in NO_x emissions that contribute to the formation of ozone.

Fiscal implications are anticipated for certain facilities with natural gas compressor stations with stationary internal combustion engines in the DFW area.

The proposed amendments would establish new emission specifications for gas-fired lean-burn and rich-burn stationary reciprocating internal combustion engines. The emission specifications proposed are 0.5 g/hp-hr for rich-burn and lean-burn internal combustion engines. The proposed emission specifications would affect a total of six rich-burn engines and 13 lean-burn engines in the DFW area. Any additional recordkeeping costs are estimated as negligible, since the rules do not specify explicit contents, and maintenance records are already being kept for these engines.

All six of affected rich-burn engines in the 2002 TCEQ emissions inventory may be able to obtain a 0.5 g/hp-hr limit through application of non-selective catalytic reduction. The rich-burn engines that are not capable of meeting the 0.5 g/hp-hr limit with non-selective catalytic reduction may be required to implement an additional catalyst module to achieve the proposed limit. Costs for the six engines to implement non-selective catalytic reduction controls are estimated to be $179,533, with a low of $27,666 for a 660 hp engine and a high of $39,000 for a 1,340 hp engine.

If these engines are not able to achieve the 0.5 g/hp-hr limit with the non-selective catalytic reduction control, then these engines may require an additional catalyst module to meet the proposed limits. At this time, it is not known how many would require this additional control but assuming all of them require the additional catalyst module, additional costs are estimated to be $71,580 for all six engines (based upon $15 per hp of engine rating). Total costs for these engines for the first year the controls are implemented including the catalyst module is estimated to be $251,113 ($179,533 + $71,580).

In order to ensure initial and continued emissions compliance, any owner or operator of engines subject to the emission limits would be required to perform a stack test before the initial compliance date, and every two years following. This stack test is estimated to cost approximately $3,500 per engine. The proposed rules also require emission checks at least quarterly with stain tubes or portable analyzers.

The emission check cost is estimated at $400 annually per engine. Total emission test costs for the six engines are estimated to be: $21,000 ($3,500 x 6) the first year the controls are in place; $2,400 ($400 x 6) the second year; $23,400 (stack test plus quarterly testing) the third year; $2,400 the fourth year; and $23,400 the fifth year.

Total cost for controls and testing for the rich-burn engines is estimated to be: $272,113 the first year the controls are in place; $2,400 the second year; $23,400 the third year; $2,400 the fourth year; and $23,400 the fifth year.

There is no population in the 2002 emissions inventory for rich-burn engines in Collin, Dallas, Denton, and Tarrant Counties. However, it is anticipated that any rich-burn engines that may be located in these counties could use the additional catalyst module which would allow engines operating at the current emission standard of 2.0 g/hp-hr to achieve the proposed 0.5 g/hp-hr limit. The additional catalyst module would cost an estimated $15 per hp of the engine rating.

The 2002 TCEQ emissions inventory shows that 13 lean-burn engines will be affected by the proposed rules and will require controls. These engines would be required to implement an exhaust gas recirculation kit (in order to reduce the excess oxygen) and non-selective catalytic reduction to meet the proposed 0.5 g/hp-hr emission limit. Cost estimates for the application of non-selective catalytic reduction and an exhaust gas recirculation kit for the 13 engines is estimated to be $1,527,292 with a low of $60,000 for a 500 hp engine and a high of $178,125 for a 3,335 hp engine.

In order to ensure initial and continued emissions compliance, the stack test would be required before the initial compliance date, and every two years following and is estimated to cost approximately $3,500 per engine. The rule also requires emission checks at least quarterly with stain tubes or portable analyzers. The emission check cost is estimated at $400 annually per engine. Total emission test costs for the 13 engines is estimated to be: $45,500 ($3,500 x 13), the first year the controls are in place; $5,200 ($400 x 13), the second year; $50,700 (stack test plus quarterly testing), the third year; $5,200, the fourth year; and $50,700, the fifth year.

Total cost for controls and testing for the lean-burn engines is estimated to be: $1,572,792, the first year the controls are in place; $5,200, the second year; $50,700, the third year; $5,200, the fourth year; and $50,700, the fifth year.

Total cost for the lean-burn and rich-burn engines in the first year controls are in place is estimated to be approximately $1,844,905.

SMALL BUSINESS AND MICRO-BUSINESS ASSESSMENT

No adverse fiscal implications are anticipated for small or micro-businesses. None of the stationary internal combustion engines affected by the proposed amendments in the DFW area are owned by small or micro-businesses.

LOCAL EMPLOYMENT IMPACT STATEMENT

The commission 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 considering the regulatory analysis requirements of Texas Government Code, §2001.0225, and determined that the rulemaking does not meet the definition of a "major environmental rule." 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 amendments revise the SIP. While this rulemaking is intended to protect the environment by reducing NO_x, the commission does not find that the specific lean-burn and rich-burn engines in the DFW area comprise a sector of the economy, or that the rules will adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety in the DFW area. Further, the commission does not find that the changes that add the exemption for cogeneration boilers in the BPA area and the changes to improve the implementation of the requirements for compliance with existing rules in the BPA area, DFW area, and HGB area apply to sources that comprise a sector of the economy, or that the rules will adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety in the BPA area, DFW area, and HGB area.

The proposed amendments to Chapter 117 are not subject to the regulatory analysis provisions of Texas Government Code, §2001.0225(b), because the proposed rules do not meet any of the four applicability requirements. Texas Government Code, §2001.0225 only applies to a major environmental rule, the result of which is to: 1) exceed a standard set by federal 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 proposed amendments were developed as part of the control strategy to meet the eight-hour ozone NAAQS set by the EPA under 42 USC, §7409, and therefore meet a federal requirement. In addition to the changes applicable to certain engines in the DFW area, the amendments include technical changes to improve the language to best state the commission's intent regarding current requirements for major and minor sources of NO_x emissions in ozone nonattainment areas. Each proposed change would affect one or more of the ozone nonattainment areas of the state, BPA area, DFW area, and HGB area. Title 42 USC, §7410, requires states to adopt and submit a SIP which provides for "implementation, maintenance, and enforcement" of the primary NAAQS in each air quality control region of the state. While 42 USC, §7410 does not require specific programs, methods, or reductions in order to meet the standard, 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 42 USC, Chapter 85, Air Pollution Prevention and Control). While 42 USC, §§7401 *et seq*. does require some specific measures for SIP purposes, like the inspection and maintenance program, the statute also provides flexibility for states to select other necessary or appropriate measures. The federal government, in implementing 42 USC, §§7401 *et seq.*, recognized that the states are in the best position to determine what programs and controls are necessary or appropriate to meet the NAAQS, and provided for the ability of states and the public to collaborate on the best methods for attaining the NAAQS within a particular state. However, this flexibility does not relieve a state from developing and submitting a SIP that meets the requirements of 42 USC, §7410. Thus, while specific measures are not generally required, the emission reductions are required. States are not free to ignore the requirements of 42 USC, §7410 and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule.

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, 1999. 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 delegation 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 previously discussed, 42 USC, §§7401 *et seq*. does not require specific programs, methods, or reductions in order to meet the NAAQS; thus states must develop programs for each nonattainment area to ensure that the area will meet the attainment deadlines. Because of the ongoing need to address nonattainment issues, 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 a full regulatory impact analysis 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 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 Legislative Budget Board, the intent of SB 633 was only to require the full regulatory impact analysis for rules that are extraordinary in nature. While the SIP rules may have broad impacts, those impacts are no greater than necessary or appropriate to meet the requirements of the 42 USC, §§7401 *et seq*. For these reasons, rules proposed for inclusion in the SIP fall under the exception in Texas Government Code, §2001.0225(a), because they are required by federal law.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable and 42 USC, §7511a(c), requires states to submit attainment demonstration SIPs for ozone nonattainment areas, such as the DFW area. The proposed rules, which will reduce ozone in the DFW area, will be submitted to the EPA as one of several measures in the federally required SIP. By reducing emissions of NO_x, a precursor of ozone, these controls will result in reductions in ozone formation in the BPA area, DFW area, and HGB area and help bring these areas into compliance with the air quality standards established under federal law as NAAQS for ozone. Therefore, the proposed rulemaking is a necessary component of, and consistent with, the eight-hour ozone attainment demonstration Dallas/Fort Worth SIP required by 42 USC, §7410, and for the state's existing plans for the BPA area and HGB area.

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. The commission presumes 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); *Sharp v. House of Lloyd, Inc.*, 815 S.W.2d 245 (Tex. 1991); *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).

As discussed earlier in this preamble, this rulemaking action implements requirements of 42 USC, §§7401 *et seq*. There is no contract or delegation agreement that covers the topic that is the subject of this action. 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 it adopted solely under the general powers of the agency. 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 Texas Water Code that are cited in the STATUTORY AUTHORITY section of this preamble. Therefore, this rulemaking action is not subject to the regulatory analysis provisions of Texas Government Code, §2001.0225(b), because the proposed rulemaking does not meet any of the four applicability requirements.

The commission invites public comment on the draft regulatory impact analysis determination.

TAKINGS IMPACT ASSESSMENT

The commission completed a takings impact analysis for the proposed rulemaking action under Texas Government Code, §2007.043. The specific purposes of this rulemaking are to achieve reductions of NO_x emissions to reduce ozone formation in the DFW area and help bring the DFW area into compliance with the air quality standards established under federal law as NAAQS for ozone. In addition to the changes applicable to engines in the DFW area, the amendments include technical changes to improve the language to best state the commission's intent regarding current requirements for major and minor sources of NO_x emissions in ozone nonattainment areas. Each proposed change would affect one or more of the ozone nonattainment areas of the state, BPA area, DFW area, and HGB area. If certain amendments are adopted, certain engines located in the DFW area may be required to install equipment to monitor emissions and implement new reporting and recordkeeping requirements. Installation of the necessary equipment could conceivably place a burden on private, real property. Other amendments provide clarification as to monitoring and reporting requirements and will not place a burden on private, real property.

Texas Government Code, §2007.003(b)(4), provides that Chapter 2007 does not apply to this proposed rulemaking action, because it is reasonably taken to fulfill an obligation mandated by federal law. The emission limitations and control requirements within this rulemaking action were developed in order to meet the eight-hour ozone NAAQS set by the EPA under 42 USC, §7409. States are primarily responsible for ensuring attainment and maintenance of NAAQS once the EPA has established them. Under 42 USC, §7410, and related provisions, states must submit, for approval by the EPA, SIPs that provide for the attainment and maintenance of NAAQS through control programs directed to sources of the pollutants involved. Therefore, one purpose of this rulemaking action is to meet the air quality standards established under federal law as NAAQS. Attainment of the eight-hour ozone standard may require further reductions in NO_x emissions as well as VOC emissions. This rulemaking is one step toward meeting the state's obligations under the FCAA.

In addition, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rules do not directly prevent a nuisance or prevent an immediate threat to life or property, they do prevent a real and substantial threat to public health and safety and significantly advance the health and safety purpose. This action is taken in response to the DFW area exceeding the federal eight-hour ozone NAAQS, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ozone levels in the DFW area. Consequently, these proposed rules meet the exemption in Texas Government Code, §2007.003(b)(13). This rulemaking action therefore meets the requirements of Texas Government Code, §2007.003(b)(4) and (13). For these reasons, the proposed rules do not constitute a takings under 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 will 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 amendments 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; therefore, owners or operators subject to the federal operating permit program must, consistent with the revision process in Chapter 122, revise their operating permit to include the revised Chapter 117 requirements at their sites affected by the revisions to Chapter 117.

ANNOUNCEMENT OF HEARINGS

Public hearings on this proposal will be held on January 3, 2005, at 5:30 p.m. at the North Central Texas Council of Governments, 616 Six Flags Drive, Transportation Board Room, 3rd Floor, Arlington, Texas; January 4, 2005, at 10:00 a.m. at the Texas Commission on Environmental Quality, 12100 North I-35, Building F, Room 2210, Austin, Texas; and January 5, 2005, at 2:30 p.m. at the Houston-Galveston Area Council, Conference Room A, 3555 Timmons Lane, Houston, Texas. Individuals may present oral statements when called upon in order of registration. Open discussion will not occur during the hearings; however, a staff member will be available to discuss the proposal 30 minutes before the hearings and will answer questions before and after the hearings.

Persons with disabilities who have special communication or other accommodation needs, who are planning to attend the hearing, should contact the Office of Environmental Policy, Analysis, and Assessment at (512) 239-4900. Requests should be made as far in advance as possible.

SUBMITTAL OF COMMENTS

Comments may be submitted to Patricia Durón, MC 205, Office of Environmental Policy, Analysis, and Assessment, Texas Commission on Environmental Quality, P.O. Box 13087, Austin, Texas 78711-3087; faxed to (512) 239-4808; or emailed to *siprules@tceq.state.tx.us* with Rule Project Number 2005-004-117-AI in the subject line. All comments should reference Rule Project Number 2005-004-117-AI. Comments must be received by 5:00 p.m., January 6, 2005. For further information, please contact Karen Hill of the Environmental Planning and Implementation Division at (512) 239-2968 or Emily Barrett of the Policy and Regulations Division at (512) 239-3546.

SUBCHAPTER B: COMBUSTION AT MAJOR SOURCES

DIVISION 1: UTILITY ELECTRIC GENERATION IN OZONE NONATTAINMENT AREAS

§117.114

STATUTORY AUTHORITY

The amendment is 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; and under Texas Health and Safety Code, §382.017, concerning Rules, that authorizes the commission to adopt rules consistent with the policy and purposes of the Texas Clean Air Act. The amendments are also proposed under Texas Health and Safety Code, §382.002, concerning Policy and Purpose, that establishes the commission's purpose to safeguard the state air resources, consistent with the protection of public health, general welfare, and physical property; §382.011, concerning General Powers and Duties, that authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, that authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; and §382.016, concerning Monitoring Requirements; Examination of Records, that authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants. The amendment is also proposed under 42 USC, §7410, that require states to introduce pollution control measures in order to reach specific air quality standards in particular areas of the state.

The proposed amendment implements Texas Health and Safety Code, §§382.002, 382.011, 382.012 and 382.016.

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

(a) Monitoring requirements. The owner or operator of units which are subject to the emission limits of §117.106(c) of this title (relating to Emission Specifications for Attainment Demonstrations) must comply with the following monitoring requirements.

(1) The nitrogen oxides (NO_x) monitoring requirements of §117.113(a) and (c) - (f) of this title (relating to Continuous Demonstration of Compliance) apply.

(2) The carbon monoxide (CO) monitoring requirements of §117.113(b) of this title apply.

(3) The totalizing fuel flow meter requirements of §117.113(h) of this title apply.

(4) One of the following ammonia monitoring procedures shall be used to demonstrate compliance with the ammonia emission specification of §117.106(d)(2) of this title for gas-fired or liquid-fired units which inject urea or ammonia into the exhaust stream for NO_x control.

(A) Mass balance. Calculate ammonia emissions 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 which injects urea or ammonia into the exhaust stream. Ammonia emissions must be calculated using the following equation. [The equation is: ammonia parts per million by volume (ppmv) at reference oxygen = {(a/b) (10^6) - (c)(d)}, where reference oxygen is 3.0% for boilers and 15% for gas turbines; 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 required by §117.111(a)(2) of this title (relating to Initial Demonstration of Compliance), using either the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method 27.]

Figure: 30 TAC §117.114(a)(4)(A)

$$NH_3@O_2 = \left[\left(\frac{a}{b} \times 10^6\right) - c\right] \times d$$

Where:

$NH_3@O_2$	=	ammonia parts per million by volume (ppmv) at reference oxygen. Reference oxygen is 3.0% for boilers and 15% for gas turbines.
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)
d	=	correction factor, the ratio of measured slip to calculated ammonia slip, where the measured slip is obtained from the stack sampling for ammonia required by §117.111(a)(2) of this title (relating to Initial Demonstration of Compliance), using either the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method 27. Minor modifications to these methods or EPA-approved alternative test methods may be approved by the executive director, as specified in §117.211(e)(6) of this title (relating to Initial Demonstration of Compliance).

(B) Oxidation of ammonia to nitric oxide (NO). Convert ammonia to NO using molybdenum oxidizer and measure ammonia slip by difference using a NO analyzer. The NO analyzer shall be quality assured in accordance with manufacturer's specifications and with a quarterly cylinder gas audit with a ten ppmv reference sample of ammonia passed through the probe and confirming monitor response to within ±2.0 ppmv.

(C) 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 shall be daily for the first 60 days of operation, after which 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 shall resume when the catalyst is within 30 days of its useful life expectancy. Every effort shall be made to take at least one weekly sample near the normal highest ammonia injection rate.

(D) Other methods. Monitor ammonia using another continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) procedure subject to prior approval of the executive director. [For purposes of this subparagraph, the executive director is the Engineering Services Team, Office of Compliance and Enforcement.]

(E) Records. The owner or operator shall maintain records which are sufficient to demonstrate compliance with the requirements of the appropriate subparagraph of this paragraph. For the sorbent or stain tube option, these records shall include the ammonia injection rate and NO_x stack emissions measured during each sorbent or stain tube test. The records shall be maintained for a period of at least five years. Records shall be available for inspection by the executive director, EPA, and any local air pollution control agency having jurisdiction upon request.

(5) Installation of monitors shall be performed in accordance with the schedule specified in §117.510(c)(2) of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas).

(b) Testing requirements. The owner or operator of units which are subject to the emission limits of §117.106(c) of this title must test the units as specified in §117.111 of this title in accordance with the schedule specified in §117.510(c)(2) of this title.

(c) Emission allowances.

(1) The NO_x testing and monitoring data of subsections (a) and (b) of this section, together with the level of activity, as defined in §101.350 of this title (relating to Definitions), shall 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 a CEMS or PEMS, the following apply.

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

(B) Retesting as specified in subsection (b) of this section may be conducted at the discretion of the owner or operator after any modification which 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 (FGR), and fuel-lean and conventional (fuel-rich) reburn.

(C) The NO_x emission rate determined by the retesting shall 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 shall 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.

SUBCHAPTER B: COMBUSTION AT MAJOR SOURCES

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

§§117.201, 117.203, 117.206, 117.213, 117.214

STATUTORY AUTHORITY

The amendments 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; and under Texas Health and Safety Code, §382.017, concerning Rules, that authorizes the commission to adopt rules consistent with the policy and purposes of the Texas Clean Air Act. The amendments are also proposed under Texas Health and Safety Code, §382.002, concerning Policy and Purpose, that establishes the commission's purpose to safeguard the state air resources, consistent with the protection of public health, general welfare, and physical property; §382.011, concerning General Powers and Duties, that authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, that authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; and §382.016, concerning Monitoring Requirements; Examination of Records, that authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants. The amendments are also proposed under 42 USC, §7410, that require states to introduce pollution control measures in order to reach specific air quality standards in particular areas of the state.

The proposed amendments implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, and 382.016.

§117.201. Applicability.

The provisions of this division (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas), shall apply to the following units located at any major stationary source of nitrogen oxides located within the Beaumont/Port Arthur, Dallas/Fort Worth, or Houston/Galveston ozone nonattainment areas, or as otherwise specified:

(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 which were regulated as existing facilities by the United States Environmental Protection Agency [EPA] at 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.

§117.203. Exemptions.

(a) Units exempted from the provisions of this division (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas), except as may be specified in §§117.206(i), 117.209(c)(1), 117.213(i), 117.214(a)(2), 117.216(a)(5), and 117.219(f)(6) and (10) of this title (relating to Emission Specifications for Attainment Demonstrations; Initial Control Plan Procedures; Continuous Demonstration of Compliance; Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration; Final Control Plan Procedures for Attainment

Demonstration Emission Specifications; and Notification, Recordkeeping, and Reporting Requirements), include the following:

(1) any new units placed into service after November 15, 1992, except for new units which 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 shall be 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. This exemption shall no longer apply to any heat treating furnace or reheat furnace with a maximum rated capacity of 20 MMBtu/hr or greater in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas);

(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 shall no longer apply to the following units in the Houston/Galveston ozone

nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 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 shall no longer apply to the following units in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 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, which 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 in the Houston/Galveston ozone nonattainment area 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;

(8) stationary internal combustion engines which are:

(A) located in the Houston/Galveston ozone nonattainment area with a horsepower (hp) rating of less than 150 hp; or

(B) located in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment area with a hp rating of less than 300 hp;

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

(10) any stationary diesel engine in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment area;

(11) any stationary diesel engine placed into service before October 1, 2001 in the Houston/Galveston ozone nonattainment area which:

(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]

(12) any new, modified, reconstructed, or relocated stationary diesel engine placed into service in the Houston/Galveston ozone nonattainment area on or after October 1, 2001 which:

(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; and [.]

(13) any cogeneration boiler in the Beaumont/Port Arthur ozone nonattainment area that recovers waste heat from one or more carbon black reactors.

(b) The exemptions in subsection (a)(1), (2), (7), and (8)(A) of this section shall no longer apply in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title.

(c) After June 15, 2007, the exemption in subsection (a)(1) of this section no longer applies to the engines specified in §117.206(b)(3) of this title.

§117.206. Emission Specifications for Attainment Demonstrations.

(a) Beaumont/Port Arthur. 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 (MMBtu/hr) in the Beaumont/Port Arthur ozone nonattainment area, emissions of nitrogen oxides (NO_x) in excess of the following, except as provided in subsections (f) and (g) of this section:

(1) boilers, 0.10 pound (lb) NO_x per MMBtu of heat input; and

(2) process heaters, 0.08 lb NO_x per MMBtu of heat input.

(b) Dallas/Fort Worth. No person shall allow the discharge into the atmosphere [in the Dallas/Fort Worth ozone nonattainment area,] emissions in excess of the following emission specifications, except as provided in subsections (f) and (g) of this section.[:]

(1) Gas-fired [gas-fired] boilers in Collin, Dallas, Denton, and Tarrant Counties with a maximum rated capacity equal to or greater than 40 MMBtu/hr, must comply with 30 parts per million by volume (ppmv) NO_x, at 3.0% oxygen (O_2), dry basis, according to the applicable schedule in §117.520(b)(1) of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas).[; and]

(2) Gas-fired [gas-fired] and dual-fuel [gas/liquid-fired], lean-burn, stationary reciprocating internal combustion engines in Collin, Dallas, Denton, and Tarrant Counties rated 300 horsepower (hp) or greater, must comply with 2.0 grams NO_x per horsepower hour (g NO_x/hp-hr) and 3.0 g carbon monoxide (CO)/hp-hr, according to the applicable schedule in §117.520(b)(1) of this title.

(3) Gas-fired lean-burn and gas-fired rich-burn stationary reciprocating internal combustion engines in Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties rated 300 hp or greater, must comply with 0.5 g NO_x/hp-hr, according to the applicable schedule in §117.520(b)(2) of this title.

(c) Houston/Galveston. In the Houston/Galveston ozone nonattainment area, the 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) shall 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 for which 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 MMBtu/hr, 0.020 lb NO_x per MMBtu;

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

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

(2) fluid catalytic cracking units (including 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 shall be used to calculate the 90% reduction; or

(C) alternatively, for units which 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 §117.213(e) or (f) 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) which were regulated as existing facilities by the EPA at 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 NO_x per MMBtu; and

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

(i) 0.030 lb NO_x per 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 shall be used to calculate the 80% reduction;

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

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

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

(7) liquid-fired boilers, 2.0 lb NO_x 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 NO_x per MMBtu; and

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

(B) pyrolysis reactors, 0.036 lb NO_x per MMBtu;

(9) stationary, reciprocating internal combustion engines:

(A) gas-fired rich-burn engines:

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

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

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

(C) dual-fuel engines:

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

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

(D) diesel engines, excluding dual-fuel engines:

(i) placed into service before October 1, 2001 which have not been modified, reconstructed, or relocated on or after October 1, 2001, the lower of 11.0 g NO_x/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

(ii) for engines not subject to clause (i) of this subparagraph:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(10) stationary gas turbines:

(A) rated at ten megawatts (MW) or greater, 0.032 lb NO_x per MMBtu;

(B) rated at 1.0 MW or greater, but less than ten MW, 0.15 lb NO_x per MMBtu; and

(C) rated at less than 1.0 MW, 0.26 lb NO_x per 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 NO_x per MMBtu; or

(B) 1.08 lb NO_x per air-dried ton of pulp (ADTP);

(13) kilns:

(A) lime kilns, 0.66 lb NO_x per ton of calcium oxide (CaO); and

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

(14) metallurgical furnaces:

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

(B) reheat furnaces, 0.062 lb NO_x per 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 shall be used to calculate the 80% reduction; or

(B) 0.030 lb NO_x per 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 NO_x per MMBtu. For units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor

shall 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 shall 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) NO_x averaging time.

(1) In the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, the emission limits of subsections (a) and (b) of this section shall apply:

(A) if the unit is operated with a NO_x CEMS or PEMS under §117.213 of this title, either as:

(i) a rolling 30-day average period, in the units of the applicable standard;

(ii) a block one-hour average, in the units of the applicable standard, or alternatively;

(iii) 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 NO_x per MMBtu; and

(B) if the unit is not operated with a NO_x CEMS or PEMS under §117.213 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 lbs per hour, as specified in subparagraph (A)(iii) of this paragraph.

(2) In the Houston/Galveston ozone nonattainment area, the averaging time for the emission limits of subsection (c) of this section shall be as specified in Chapter 101, Subchapter H, Division 3 of this title, except that electric generating facilities (EGFs) shall also comply with the daily and 30-day system cap emission limitations of §117.210 of this title (relating to System Cap).

(e) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to NO_x emission specifications in subsection (a), (b), or (c) of this section, emissions in excess of the following, except as provided in §117.221 of this title (relating to Alternative Case Specific Specifications) or paragraph (3) or (4) of this subsection:

(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; 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; and

(2) for units which inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions of ten 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 which were regulated as existing facilities by the EPA at 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) stationary internal combustion engines subject to subsection (b)(2) of this section or §117.205(e) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT));

(B) BIF units which were regulated as existing facilities by the EPA at 40 CFR Part 266, Subpart H (as was in effect on June 9, 1993) and which are subject to subsection (c)(3) of this section; and

(C) 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.

(f) Compliance flexibility.

(1) In the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, an owner or operator may use any of the following alternative methods to comply with the NO_x emission specifications of this section:

(A) §117.207 of this title (relating to Alternative Plant-wide Emission Specifications);

(B) §117.223 of this title (relating to Source Cap); or

(C) §117.570 (relating to Use of Emissions Credits for Compliance).

(2) Section 117.221 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 limits of this section in accordance with §117.221 of this title.

(4) In the Houston/Galveston ozone nonattainment area, an owner or operator may not use the alternative methods specified in §§117.207, 117.223, and 117.570 of this title 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 EGFs shall also comply with the daily and 30-day system cap emission limitations of §117.210 of this title. An owner or operator may use the alternative methods specified in §117.570 of this title for purposes of complying with §117.210 of this title.

(g) Exemptions. Units exempted from the emissions specifications of this section include the following in the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas:

(1) any industrial, commercial, or institutional boiler or process heater with a maximum rated capacity less than 40 MMBtu/hr; and

(2) units exempted from emission specifications in §117.205(h)(2) - (5) and (9) of this title.

(h) Prohibition of circumvention. In the Houston/Galveston ozone nonattainment area:

(1) the maximum rated capacity used to determine the applicability of the emission specifications in subsection (c) of this section and the initial control plan, compliance demonstration, monitoring, testing requirements, and final control plan in §§117.209, 117.211, 117.213, 117.214, and 117.216 of this title (relating to Initial Control Plan Procedures; Initial Demonstration of Compliance; Continuous Demonstration of Compliance; Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration; and Final Control Plan Procedures for Attainment Demonstration Emission Specifications) shall 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 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;

(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, shall be 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, shall be 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 subsection (c) of this section (ESAD unit) which 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 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 which meets the requirements of §117.213(e) or (f) of this title, or through stack testing which meets the requirements of §117.211(e) of this title [(relating to Initial Demonstration of Compliance)]; 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 which met the definition of major source on December 31, 2000 shall always be classified as a major source for purposes of this chapter. A source which did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2000, but which at any time after December 31, 2000 becomes a major source, shall from that time forward always be classified as a major source for purposes of this chapter; and

(5) the availability under subsection (c)(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 (c)(17) of this section than would otherwise apply to the unit.

(i) Operating restrictions. In the Houston/Galveston ozone nonattainment area, 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.

§117.213. 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 which 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:

(A) for units which are subject to §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), for stationary gas turbines which are exempt under §117.205(h)(7) of this title, and for units in the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas which are subject to §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations):

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

(I) boilers;

(II) process heaters;

(III) boilers and industrial furnaces which were regulated as existing facilities by EPA at 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 §117.203(a)(6) or (8) of this title (relating to Exemptions), or §117.205(h)(9) or (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 in the Houston/Galveston ozone nonattainment area which are subject to §117.206 of this title:

(i) boilers (excluding wood-fired boilers that must comply by maintaining records of fuel usage as required in §117.219(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 which were regulated as existing facilities by EPA at 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 incinerators that control vapor streams resulting from vessel cleaning, 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).

(2) The following are alternatives [As an alternative] to the fuel flow monitoring requirements of paragraph (1) of this subsection. [,]

(A) Units [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 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.

(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 $2.2(10^{11})$ Btu 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:

(i) greater than or equal to 100 MMBtu/hr and less than 200 MMBtu/hr; and

(ii) greater than or equal to 200 MMBtu/hr, except as provided in subsection (f) of this section.

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

(A) units listed in §117.205(h)(3) - (5) and (8) - (10) of this title;

(B) process heaters operating with a carbon dioxide (CO_2) 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 [necessitated] 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 located in the Beaumont/Port Arthur ozone nonattainment area which 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 which use a chemical reagent for reduction of NO_x;

(F) units for which the owner or operator elects to comply with the NO_x emission specifications of §117.205 or §117.206(a) or (b) of this title using a pound per MMBtu (lb/MMBtu) limit on a 30-day rolling average;

(G) lime kilns and lightweight aggregate kilns in the Houston/Galveston ozone nonattainment area;

(H) units with a rated heat input greater than or equal to 100 MMBtu/hr which are subject to §117.206(c) of this title; and

(I) 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 §117.205 or §117.206(a) or (b) of this title, units listed in §117.205(h)(3) - (5) and (8) - (10) of this title; and

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

<u>(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:</u>

<u>(A) if the NO_x monitor is a CEMS:</u>

<u>(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</u>

(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 §117.113(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 §117.113(f) of this title; 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 §117.211(f) of this title (relating to Initial Demonstration of Compliance).

(d) 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 following methods:

(1) install, calibrate, maintain, and operate a:

(A) CEMS in accordance with subsection (e) of this section; or

(B) PEMS in accordance with subsection (f) of this section; or

(2) sample CO as follows:

(A) with a portable analyzer (or 40 CFR Part 60, Appendix A reference method test apparatus) after manual combustion tuning or manual burner adjustments conducted for the purpose of minimizing 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 for which 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.

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

(1) Except as specified in paragraph (5) of this subsection, the CEMS shall meet the requirements of 40 CFR Part 60 as follows:

(A) Section 60.13;

(B) Appendix B:

(i) Performance Specification 2, for NO_x in terms of the applicable standard (in parts per million by volume (ppmv), lb/MMBtu, or grams per horsepower-hour (g/hp-hr)). An alternative relative accuracy requirement of $\pm$ 2.0 ppmv from the reference method mean value is allowed;

(ii) Performance Specification 3, for diluent; and

(iii) Performance Specification 4, for CO, for owners or operators electing to use a CO CEMS; and

(C) after the final 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. However, 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) Monitor diluent, either O_2 [0_2] or CO_2, unless using an exhaust flow meter as provided in subsection (a)(2) of this section.

(3) For units which are subject to §117.205 of this title, and for units in the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas [, one CEMS may be shared among units, provided]:

(A) each individual stack must be analyzed separately for single units with multiple exhaust stacks; and

(B) one CEMS may be shared among units or among multiple exhaust stacks on a single unit, provided:

(i) [(A)] the exhaust stream of each stack [unit] is analyzed separately; and

(ii) [(B)] the CEMS meets the certification requirements of paragraph (1) of this subsection for each exhaust stream while the CEMS is operating in the time-shared mode.

(4) For units in the Houston/Galveston ozone nonattainment area which are subject to §117.206 of this title:

(A) all bypass stacks must [shall] 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 shall be introduced between the CEMS and the bypass stack; and

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

(B) one CEMS may be shared among units or among multiple exhaust stacks on a single unit, provided:

(i) the exhaust stream of each stack is analyzed separately;

(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 which vent to a common stack do not need to be analyzed separately[.] ; and

(D) 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) Section 1 (Installation and Measurement Location);

(ii) Section 2 (Equipment Specifications);

(iii) Section 3 (Performance Specifications);

(iv) Section 4 (Data Acquisition and Handling Systems);

(v) Section 5 (Calibration Gas);

(vi) Section 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 $\pm$ 2.0 ppmv from the reference method mean value; and

(E) appropriate quality assurance/quality control (QA/QC) procedures in Appendix B, as follows:

(i) Section 1 (Quality Assurance/Quality Control Program); and

(ii) Section 2 (Frequency of Testing).

(6) The CEMS shall be subject to the approval of the executive director.

(f) PEMS requirements. The owner or operator of any PEMS used to meet a pollutant monitoring requirement of this section must 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 Continuous Demonstration of Compliance).

(2) Monitor diluent, either O_2 or CO_2:

(A) using a CEMS:

(i) in accordance with subsection (e)(1)(B)(ii) of this section; or

(ii) with a similar alternative method approved by the executive director and EPA; or

(B) using a PEMS.

(3) Any PEMS shall meet the requirements of 40 CFR Part 75, Subpart E, except as provided in paragraphs (4) and (5) of this subsection.

(4) 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 EPA 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.

(5) 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 $\pm$ 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 shall be based on a minimum of 30 successive emission data points at each tested level which are either 15-minute, 20-minute, or hourly averages;

(II) the F-test shall be performed separately at each tested level;

(III) the t-test and the correlation analysis shall 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 shall 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 is to 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 shall be submitted with the request for waiver. The statistical test shall 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 [shall] be submitted to the executive director [Engineering Services Team, Office of Compliance and Enforcement] for review. The executive director [manager of the Engineering Services Team] 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 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 $\pm$ 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 parts per million by volume.

(6) The owner or operator shall, for each alternative fuel fired in a unit, certify the PEMS in accordance with paragraph (5)(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.

(7) The PEMS shall be subject to the approval of the executive director.

(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 follows.

(1) Engines not using NO_x CEMS or PEMS.

(A) Use the methods specified in §117.211(e) of this title [(relating to Initial Demonstration of Compliance)].

(B) Sample:

(i) on a biennial calendar basis; or

(ii) 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:

(-a-) documentation of the actual recorded hours of engine operation since the previous emission test; and

(-b-) an estimate of the date of the next required sampling.

(C) Engines used exclusively in emergency situations are not required to conduct the testing specified in subparagraph (B) of this paragraph.

(2) Engines using NO_x CEMS or PEMS. Engines which use a chemical reagent for reduction of NO_x shall monitor in accordance with subsection (c)(1)(E) of this section and shall comply with the applicable requirements of this section for CEMS and PEMS.

(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 §117.207 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 shall be accurate to within $\pm$ 5.0%;

(B) the steam-to-fuel or water-to-fuel ratio monitoring data shall constitute the method for demonstrating continuous compliance with the applicable emission specification of §117.205 or §117.207 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 §117.205(h)(2) or (9) or §117.203(a)(6)(D), (11), or (12) 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 shall be non-resettable.

(j) Hydrogen (H_2) monitoring. The owner or operator claiming the H_2 multiplier of §117.205(b)(6) or §117.207(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 will 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 shall be tested according to American Society of Testing and Materials (ASTM) Method D1945-81 or ASTM Method D2650-83, or other methods which are demonstrated to the satisfaction of the executive director and the EPA 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 shall 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 which is the source of the H_2 shall 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.

(1) After the initial demonstration of compliance required by §117.211 of this title, the methods required in this section shall be used to determine compliance with the emission specifications of §117.205 or §117.206(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 limitations.

(2) For units subject to the emission specifications of §117.206(c) of this title, the methods required in this section and §117.214 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) shall be used in conjunction with the requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) to determine compliance. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission limitations.

(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 shall be operated at an emission rate higher than that allowed by the emission specifications of §117.205 of this title. If compliance with §117.207 of this title is selected, no unit subject to §117.207 of this title shall be operated at an emission rate higher than that approved by the executive director under §117.215(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 §117.205(h)(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 shall be 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 shall include a schedule of increments of progress for the installation of the required control equipment.

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

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

(a) Monitoring requirements.

(1) The owner or operator of units which are subject to the emission limits of §117.206(c) of this title (relating to Emission Specifications for Attainment Demonstrations) must comply with the following monitoring requirements.

(A) The nitrogen oxides (NO_x) monitoring requirements of §117.213(c), (e), and (f) of this title (relating to Continuous Demonstration of Compliance) apply.

(B) The carbon monoxide (CO) monitoring requirements of §117.213(d) of this title apply.

(C) The totalizing fuel flow meter requirements of §117.213(a) of this title apply.

(D) One of the following ammonia monitoring procedures shall be used to demonstrate compliance with the ammonia emission specification of §117.206(e)(2) of this title for gas-fired or liquid-fired units which inject urea or ammonia into the exhaust stream for NO_x control.

(i) Mass balance. Calculate ammonia emissions 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 which injects urea or ammonia into the exhaust stream. The ammonia emissions must be calculated using the following equation. [The equation is: ammonia parts per million by volume (ppmv) at reference oxygen = {(a/b) (10^6) - (c)(d)}, where reference oxygen on a dry basis is 3.0% for boilers and process heaters, 0.0% for fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents), 7.0% for boilers and industrial furnaces (BIF units) which were regulated as existing facilities by the EPA at 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 required by §117.211(a)(2) of this title (relating to Initial Demonstration of Compliance), using either the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method 27.]

Figure: 30 TAC §117.214(a)(1)(D)(i)

$$NH_3@O_2 = \left[\left(\frac{a}{b} \times 10^6\right) - c\right] \times d$$

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 CO boilers, CO furnaces, and catalyst regenerator vents); 7.0% for boilers and industrial furnaces (BIF units) that were regulated as existing facilities by the EPA at 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)
d	=	correction factor, the ratio of measured slip to calculated ammonia slip, where the measured slip is obtained from the stack sampling for ammonia required by §117.111(a)(2) of this title (relating to Initial Demonstration of Compliance), using either the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method 27. Minor modifications to these methods or EPA-approved alternative test methods may be approved by the executive director, as specified in §117.211(e)(6) of this title (relating to Initial Demonstration of Compliance).

(ii) Oxidation of ammonia to nitric oxide (NO). Convert ammonia to NO using molybdenum oxidizer and measure ammonia slip by difference using a NO analyzer. The

NO analyzer shall be quality assured in accordance with manufacturer's specifications and with a quarterly cylinder gas audit with a ten parts per million by volume (ppmv) [ppmv] reference sample of ammonia passed through the probe and confirming monitor response to within ± 2.0 ppmv.

(iii) 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 shall be daily for the first 60 days of operation, after which 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 shall resume when the catalyst is within 30 days of its useful life expectancy. Every effort shall be made to take at least one weekly sample near the normal highest ammonia injection rate.

(iv) Other methods. Monitor ammonia using another continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) procedure subject to prior approval of the executive director. [For purposes of this clause, the executive director is the Engineering Services Team, Office of Compliance and Enforcement.]

(v) Records. The owner or operator shall maintain records which are sufficient to demonstrate compliance with the requirements of the appropriate clause of this subparagraph. For the sorbent or stain tube option, these records shall include the ammonia injection rate and NO_x stack emissions measured during each sorbent or stain tube test. The records shall be maintained for a period of at least five years. Records shall be available for inspection by the executive director, EPA, and any local air pollution control agency having jurisdiction upon request.

(E) Installation of monitors shall be performed in accordance with the schedule specified in §117.520(c)(2) of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas).

(2) The owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.203(a)(6)(D), (11), or (12) of this title (relating to Exemptions) shall comply with the run time meter requirements of §117.213(i) of this title.

(b) Testing and operating requirements.

(1) The owner or operator of units which are subject to the emission limits of §117.206(c) of this title must test the units as specified in §117.211 of this title in accordance with the schedule specified in §117.520(c)(2) of this title.

(2) Each stationary internal combustion engine which is not equipped with a CEMS or PEMS [continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS)] shall:

(A) be checked for proper operation of the engine by 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 which may reasonably be expected to increase emissions, oxygen (O_2) sensor replacement, or catalyst cleaning or catalyst replacement. Stain tube indicators specifically designed to measure NO_x concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x analyzers shall also be 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; and [.]

(B) be periodically tested as specified in §117.213(g)(1) of this title.

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

(c) Emission allowances.

(1) The NO_x testing and monitoring data of subsections (a) and (b) of this section, together with the level of activity, as defined in §101.350 of this title (relating to Definitions), shall 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 (b)(1) of this section is required within 60 days after any modification which could reasonably be expected to increase the NO_x emission rate.

(B) Retesting as specified in subsection (b)(1) of this section may be conducted at the discretion of the owner or operator after any modification which 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 (FGR), and fuel-lean and conventional (fuel-rich) reburn.

(C) The NO_x emission rate determined by the retesting shall 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 shall 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.

SUBCHAPTER D: SMALL COMBUSTION SOURCES

DIVISION 2: BOILERS, PROCESS HEATERS, AND STATIONARY ENGINES AND GAS TURBINES AT MINOR SOURCES

§117.479

STATUTORY AUTHORITY

The amendment is 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; and under Texas Health and Safety Code, §382.017, concerning Rules, that authorizes the commission to adopt rules consistent with the policy and purposes of the Texas Clean Air Act. The amendments are also proposed under Texas Health and Safety Code, §382.002, concerning Policy and Purpose, that establishes the commission's purpose to safeguard the state air resources, consistent with the protection of public health, general welfare, and physical property; §382.011, concerning General Powers and Duties, that authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, that authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; and §382.016, concerning Monitoring Requirements; Examination of Records, that authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants. The amendment is also proposed under 42 USC, §7410, that require states to introduce pollution control measures in order to reach specific air quality standards in particular areas of the state.

The proposed amendment implements Texas Health and Safety Code, §§382.002, 382.011, 382.012, and 382.016.

§117.479. Monitoring, Recordkeeping, and Reporting Requirements.

(a) Totalizing fuel flow meters.

(1) The owner or operator of each unit subject to the emission limitations of §117.475 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 claimed exempt under §117.473(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 which 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 [As an alternative] to the fuel flow monitoring requirements of this subsection. [,]

(A) Units [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 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 (lb/MMBtu) or grams per horsepower-hour (g/hp-hr)) are used for reporting purposes in §101.359 of this title (relating to Reporting) for all units sharing the totalizing fuel flow meter.

(b) Oxygen (O_2) monitors. If the owner or operator installs an O_2 monitor, the criteria in §117.213(e) of this title (relating to Continuous Demonstration of Compliance) 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 shall meet the requirements of §117.213(e) or (f) of this title.

(d) Monitor installation schedule. Installation of monitors shall be performed in accordance with the schedule specified in §117.534 of this title (relating to Compliance Schedule for Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources).

(e) Testing requirements. The owner or operator of any unit subject to the emission limitations of §117.475 of this title shall comply with the following testing requirements.

(1) Each unit shall be tested for NO_x, carbon monoxide (CO), and O_2 emissions.

(2) One of the ammonia monitoring procedures specified in §117.214(a)(1)(D) of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) shall be used to demonstrate compliance with the ammonia emission specification of §117.475(i)(2) of this title for units which inject urea or ammonia into the exhaust stream for NO_x control.

(3) All testing shall be conducted while operating at the maximum rated capacity, or as near thereto as practicable. Compliance shall be determined by the average of three one-hour emission test runs. Shorter test times may be used, if approved by the executive director. The following test methods must be used [, using the following test methods]:

(A) Test Method 7E or 20 (40 CFR Part 60, Appendix A) for NO_x;

(B) Test Method 10, 10A, or 10B (40 CFR Part 60, Appendix A) for CO;

(C) Test Method 3A or 20 (40 CFR Part 60, Appendix A) for O_2;

(D) Test Method 2 (40 CFR Part 60, Appendix A) for exhaust gas flow and following the measurement site criteria of Test Method 1, §2.1 (40 CFR Part 60, Appendix A), or Test Method 19 (40 CFR Part 60, Appendix A) for exhaust gas flow in conjunction with the measurement site criteria of Performance Specification 2, §3.2 (40 CFR Part 60, Appendix B);

(E) American Society of 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

(F) EPA-approved alternate test methods or minor modifications to these test methods as approved by the executive director, as long as the minor modifications meet the following conditions:

(i) the change does not affect the stringency of the applicable emission limitation; and

(ii) the change affects only a single source or facility application.

(4) Test results shall be reported in the units of the applicable emission limits 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 §117.211(g) of this title (relating to Initial Demonstration of Compliance).

(5) For units equipped with CEMS or PEMS, the CEMS or PEMS shall be installed and operational before testing under this subsection. Verification of operational status shall, as 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 §117.475 of this title for units operating with CEMS or PEMS shall 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 which 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 which 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 (FGR), and fuel-lean and conventional (fuel-rich) reburn.

(C) The NO_x emission rate determined by the retesting shall 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 shall be used to calculate actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title [(relating to Mass Emissions Cap and Trade Program)].

(8) Testing shall be performed in accordance with the schedule specified in §117.534 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 which 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), shall 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) Recordkeeping. The owner or operator of a unit subject to the emission limitations of §117.475 of this title or claimed exempt under §117.473(b) of this title shall maintain written or electronic records of the data specified in this subsection. Such records shall be kept for a period of at least five years and shall be made available upon request by authorized representatives of the executive director, the United States Environmental Protection Agency (EPA), or local air pollution control agencies having jurisdiction. The records shall include:

(1) records of annual fuel usage;

(2) for each unit using a CEMS or PEMS in accordance with subsection (c) of this section, 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; and

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

(i) pound per million British thermal units (Btu) heat input; and

(ii) pounds or tons per day;

(3) for each stationary internal combustion engine subject to the emission limitations of §117.475 of this title, records of:

(A) emissions measurements required by §117.478(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 CO measurements specified in §117.478(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 subsection (e) of this section.

(h) Records for exempt engines. Written records of the number of hours of operation for each day's operation shall be made for each engine claimed exempt under §117.473(a)(2)(E), (H), or (I) of this title (relating to Exemptions) or §117.478(b)(5) of this title. In addition, for each engine claimed exempt under §117.473(a)(2)(E) of this title, written records shall 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 shall be maintained for at least five years and shall be made available upon request to representatives of the executive director, EPA, or any local air pollution control agency having jurisdiction.

(i) Run time meters. The owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.473(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 shall be non-resettable.

(j) 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, EPA, 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.

SUBCHAPTER E: ADMINISTRATIVE PROVISIONS

§117.520

STATUTORY AUTHORITY

The amendment is 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; and under Texas Health and Safety Code, §382.017, concerning Rules, that authorizes the commission to adopt rules consistent with the policy and purposes of the Texas Clean Air Act. The amendments are also proposed under Texas Health and Safety Code, §382.002, concerning Policy and Purpose, that establishes the commission's purpose to safeguard the state air resources, consistent with the protection of public health, general welfare, and physical property; §382.011, concerning General Powers and Duties, that authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, that authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; and §382.016, concerning Monitoring Requirements; Examination of Records, that authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants. The amendment is also proposed under 42 USC, §7410, that require states to introduce pollution control measures in order to reach specific air quality standards in particular areas of the state.

The proposed amendment implements Texas Health and Safety Code, §§382.002, 382.011, 382.012, and 382.016.

§117.520. Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas.

(a) 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 3 of this chapter (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) as soon as practicable, but no later than the dates specified in this subsection.

(1) Reasonably available control technology (RACT). 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 subsection (relating to lean-burn engines) and paragraph (3) of this subsection (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 §117.211 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 §117.213 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 §117.213(e)(1)(A) and (B) and (f)(3) - (5)(A) of this title; and

(ii) the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title;

(iii) no later than:

(I) November 15, 1999, for units complying with the nitrogen oxides (NO_x) emission limit on an hourly average; and

(II) January 15, 2000, 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 §117.215 of this title (relating to Final Control Plan Procedures), no later than November 15, 1999; and

(D) the first semiannual report required by §117.219(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 §117.205(e) of this title (relating to Emission Specifications), comply with the requirements of Subchapter B, Division 3 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 which contains:

(i) the information specified in §117.215 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 §117.219(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 §117.206(a) of this title (relating to Emission Specifications for Attainment Demonstrations) 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 §117.206(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 §117.206(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 §117.206(a) of this title using the alternative methods to comply, either:

(I) §117.207 of this title (relating to Alternative Plant-wide Emission Specifications);

(II) §117.223 of this title (relating to Source Cap); or

(III) §117.570 of this title (relating to Use of Emissions Credits for Compliance);

(B) May 1, 2003, submit to the executive director:

(i) identification of enforceable emission limits which 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 §117.211 of this title;

(iii) for units newly operating with CEMS or PEMS to comply with the monitoring requirements of §117.213(c)(1)(C) of this title or §117.223 of this title, the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.213(e)(1)(A) and (B) and (f)(3) - (5)(A) of this title;

(iv) the information specified in §117.216 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 §117.206(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 §117.211 of this title, for units complying with the NO_x emission limit on a rolling 30-day average; and

(ii) the first semiannual report required by §117.213(c)(1)(C), §117.219(e), and §117.223(e) of this title, covering the period May 1, 2003 through June 30, 2003;

(D) May 1, 2005, comply with §117.206(a) of this title;

(E) May 1, 2005, submit a revised final control plan which contains:

(i) a demonstration of compliance with §117.206(a) of this title;

(ii) the information specified in §117.216 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 §117.206(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 §117.211 of this title, if using the 30-day average source cap NO_x emission limit to comply with the emission specifications in §117.206(a) of this title.

(b) The owner or operator of each industrial, commercial, and institutional source in the Dallas/Fort Worth ozone nonattainment area shall:

(1) comply with the requirements of Subchapter B, Division 3 of this chapter as soon as practicable, but no later than March 31, 2002 (final compliance date), except as specified in paragraph (2) of this subsection. The owner or operator shall:

(A) [(1)] install all NO_x abatement equipment and implement all NO_x control techniques no later than March 31, 2002; and

(B) [(2)] submit to the executive director:

(i) [(A)] for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title as early as practicable, but in no case later than March 31, 2002;

(ii) [(B)] for units operating with CEMS or PEMS in accordance with §117.213 of this title, the results of:

(I) [(i)] the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.213(e)(1)(A) and (B) and (f)(3) - (5)(A) of this title; [and]

(II) [(ii)] the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title; and

(III) [(iii)] no later than:

(-a-) [(I)] March 31, 2002, for units complying with the NO_x emission limit on an hourly average; and

(-b-) [(II)] May 31, 2002, for units complying with the NO_x emission limit on a rolling 30-day average;

(iii) [(C)] a final control plan for compliance in accordance with §117.215 of this title, no later than March 31, 2002; and

(iv) [(D)] the first semiannual report required by §117.219(d) or (e) of this title, covering the period March 31, 2002 through June 30, 2002, no later than July 31, 2002; and [.]

(2) comply with the requirements of §117.206(b)(3) of this title as soon as practicable, but no later than June 15, 2007, (the final compliance date). The owner or operator shall:

(A) install all NO_x abatement equipment and implement all NO_x control techniques no later than June 15, 2007; and

(B) 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 §117.211 of this title as early as practicable, but in no case later than June 15, 2007;

(ii) for units operating with CEMS or PEMS in accordance with §117.213 of this title, the results of:

(I) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.213(e)(1)(A) and (B) and (f)(3) - (5)(A) of this title;

(II) the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title; and

(III) no later than:

(-a-) June 15, 2007, for units complying with the NO_x emission limit on an hourly average; and

(-b-) June 15, 2007, for units complying with the NO_x emission limit on a rolling 30-day average;

(iii) a final control plan for compliance in accordance with §117.215 of this title, no later than June 15, 2007; and

(iv) the first semiannual report required by §117.219(d) or (e) of this title, covering the period June 15, 2007 through December 31, 2007, no later than January 31, 2008.

(c) The owner or operator of each industrial, commercial, and institutional source in the Houston/Galveston ozone nonattainment area shall comply with the requirements of Subchapter B, Division 3 of this chapter as soon as practicable, but no later than the dates specified in this subsection.

(1) Reasonably available control technology [(RACT)]. 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 subsection (relating to emission specifications for attainment demonstration), by November 15, 1999 (final compliance date); and

(A) submit a plan for compliance in accordance with §117.209 of this title (relating to Initial Control Plan Procedures) according to the following schedule:

(i) for major sources of NO_x which 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 which 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 [subparagraph (A) or (B) of this paragraph], submit the information required by §117.209(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 CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title; 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 §117.213 of this title, submit the results of:

(I) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.213(e)(1)(A) and (B) and (f)(3) - (5)(A) of this title; and

(II) the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title;

(III) no later than:

(-a-) November 15, 1999, for units complying with the NO_x emission limit on an hourly average; and

(-b-) January 15, 2000, for units complying with the NO_x emission limit on a rolling 30-day average;

(iii) a final control plan for compliance in accordance with §117.215 of this title, no later than November 15, 1999; and

(iv) the first semiannual report required by §117.219(d) or (e) of this title, 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 shall comply with the requirements of §117.214 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) as soon as practicable, but no later than:

(i) March 31, 2005, install any totalizing fuel flow meters, run time meters, and emissions monitors required by §117.214 of this title, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.214 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 or emissions monitors, submit to the executive director the results of:

(I) stack tests conducted in accordance with §117.211 of this title. For a stack test conducted before March 31, 2005 on a unit not equipped with CEMS or PEMS for which CEMS or PEMS must be installed no later than March 31, 2005, the requirements of §117.211(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 §117.213(e)(1)(A) and (B) and (f)(3) - (5)(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.

(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 §117.210 of this title (relating to System Cap) for EGFs which were 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 <u>or are chosen out of the first five years of operation</u>, submit to the executive director the certification of activity level, H_i, specified in §117.210 of this title for EGFs which were not in operation prior to January 1, 1997; and

(iii) comply with the requirements of §117.210 of this title as soon as practicable, but no later than March 31, 2007.

(C) For any units subject to §117.206(c) of this title for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph (2)(A) of this subsection, 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 §117.211 of this title; or, as applicable,

(ii) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.213(e)(1)(A) and (B) and (f)(3) - (5)(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 will be permanently shut down on or before May 31, 2005, may elect to comply with §117.214(a) of this title by performing a stack test 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 shut down on or before May 31, 2005;

(II) the projected date(s) each unit will be permanently shut down; and

(III) the projected date(s) of the stack tests that will be performed in accordance with clause (ii) of this subparagraph;

(ii) the stack test is performed in accordance with §117.211 of this title after March 31, 2005, and prior to May 31, 2005, while operating at maximum rated capacity, or as near thereto as practicable. For the time period from March 31, 2005, and May 31, 2005, the results of this testing must be used for demonstrating compliance with the emission specifications in §117.206(c) 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 in which a totalizing fuel flow meter has not been installed as required in §117.214(a)(1)(C) 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 May 31, 2005, the owner or operator will be considered in violation of this section as of March 31, 2005, and extensions beyond May 31, 2005, will not be granted.