The Texas Natural Resource Conservation Commission (TNRCC or commission) proposes amendments to §117.10, concerning Definitions; §§117.101, 117.103, 117.106 - 117.110, and 117.119, concerning Utility Electric Generation in Ozone Nonattainment Areas; §117.138, concerning System Cap; §§117.203, 117.206, 117.210, 117.213, 117.214, and 117.219, concerning Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas; §§117.471, 117.473, 117.475, 117.478, and 117.479, concerning Boilers, Process Heaters, and Stationary Engines at Minor Sources; and §§117.510, 117.520, 117.534, and 117.570, concerning Administrative Provisions; and corresponding revisions to the state implementation plan (SIP).

The proposed amendments to Chapter 117, concerning Control of Air Pollution from Nitrogen Compounds, and revisions to the SIP would require stationary diesel and dual-fuel engines in the Houston/Galveston (HGA) ozone nonattainment area to meet new emission specifications and operating restrictions in order to reduce nitrogen oxides (NO_x) emissions and ozone air pollution. The proposed amendments would also require new stationary gas turbines and duct burners at minor sources of NO_x in HGA to meet emission specifications in order to reduce NO_x emissions and ozone air pollution. In addition, the proposed amendments would improve implementation of the existing Chapter 117 by correcting typographical errors, updating cross-references, clarifying ambiguous language, adding flexibility, amending requirements to achieve the intended emission reductions of the program, and deleting the exemption for small (10 megawatts (MW) or less) electric generating units which are registered under a standard permit. Finally, the proposed amendments would revise the emission specifications for attainment demonstrations (ESADs) for electric utilities and landfill gas-fired stationary engines, revise the emission reduction schedule for sources other than electric utilities, and provide for alternate ESADs in the event that the TNRCC's continuing scientific assessment of the causes of and possible solutions to HGA's ozone nonattainment status results in a determination that attainment can be reached with fewer NO_x emission reductions from point sources concurrent with additional emission reduction strategies.

The commission proposes these amendments to Chapter 117 and revisions to the SIP as essential components of and consistent with the SIP that Texas is required to develop under the Federal Clean Air Act (FCAA) Amendments of 1990 as codified in 42 United States Code (USC), §7410, to demonstrate attainment of the national ambient air quality standard (NAAQS) for ozone. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE PROPOSED RULES

The HGA ozone nonattainment area is classified as Severe-17 under the 1990 Amendments to the FCAA as codified in 42 USC, §§7401 et seq., and therefore is required to attain the one-hour ozone standard of 0.12 part per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined as Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties, has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of several Post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base case episodes, adopted rules to achieve a 9% rate-of-progress (ROP) reduction in volatile organic compounds (VOC), and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary NO_x waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base case episodes which marginally exhibited model performance in accordance with United States Environmental Protection Agency (EPA) modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data-gathering exercise known as the Coastal Oxidant Assessment for Southeast Texas (COAST) study. The commission believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, EPA policy regarding SIP elements and timelines went through changes. Two national initiatives in particular resulted in changing deadlines and requirements. The first of these initiatives was a program conducted by the Ozone Transport Assessment Group (OTAG). This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in the OTAG program, and OTAG concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that impacted the SIP planning process is the revision to the NAAQS for ozone. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, the EPA proposed an interim implementation plan (IIP) it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development timelines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, the one-hour standard would continue to apply until it is attained. The FCAA requires that HGA attain the one-hour standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998 a revision to the HGA SIP which contained the following elements in response to EPA's guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by Subpart 2 of Title I of the FCAA to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the commission eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs as well as an acceleration simulation mode equivalent motor vehicle inspection and maintenance program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory state-wide programs adopted or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon Scenario VIf); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review; and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-1999 ROP plan by December 31, 2000; and to perform a mid-course review by May 1, 2004.

The emission reduction requirements included as part of the December 2000 SIP revision represented substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the

HGA area formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

A SIP revision for HGA was adopted by the commission on December 6, 2000 and submitted to the EPA by December 31, 2000. The December 2000 SIP contained rules, enforceable commitments, and photochemical modeling analyses in support of the HGA ozone attainment demonstration. In addition, this SIP contained Post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contained enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit a mid-course review.

In order for the HGA area to have an approvable attainment demonstration, the EPA indicated that the state must adopt those strategies modeled in the November 15, 1999 submittal and then adopt sufficient controls to close the remaining gap in NO_x emissions. The predicted emission reductions from these rules are necessary to successfully demonstrate attainment.

The HGA ozone nonattainment area will need to ultimately reduce NO_x more than 750 tons per day (tpd) to reach attainment of the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of rules which require stationary diesel and dual-fuel engines in HGA to meet new emission specifications and operating restrictions will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area.

The attainment demonstration modeling produces a target emission rate of 98 tpd of NO_x in 2007 from industrial point sources. This number includes emissions from new facilities which started operation after 1997, banked emission reduction credits, and future facilities permitted or with permit applications administratively complete by January 1, 2001. As noted in the January 12, 2001 issue of the *Texas Register* (25 TexReg 2877), as part of the December 2000 SIP revision for HGA the staff analyzed the most recent available point source NO_x emissions inventory, from 1997, categorizing the emitting sources by equipment type to identify how to reasonably obtain the necessary reductions. In the Tables and Graphics section of that issue of the *Texas Register* (25 TexReg 8481), the table titled "Potential NO_x Emission Reductions by Point Source Category for Houston/Galveston Nonattainment Area Counties" indicates the relative proportion of emissions according to equipment category. Based on this analysis, major sources in HGA were found to include 196 stationary emergency diesel engines, representing 5.4 tpd of NO_x emissions. There are an estimated 2,500 additional stationary diesel engines, mostly emergency backup generators, as well as stationary diesel engines at locations such as rock crushers, sand and gravel plants, hot mix asphaltic concrete plants, and oil and gas drilling rigs. The exact number is unknown because many of these sources have not been inventoried as point sources for the emissions inventory. It should be noted that an engine must remain at a location (a single site at a building, structure, facility, or installation) for more than 12 consecutive months to meet the definition of "stationary internal combustion engine" in §117.10. In the softer rock in HGA, as compared to West Texas, for example, oil and gas drilling rigs are unlikely to be on-site for more than 12 consecutive months, according to the Texas Railroad Commission.

The EPA has been regulating highway (on-road) cars and trucks since the early 1970s and continues to set increasingly stringent emissions standards for such vehicles. After making considerable progress in controlling the emissions from on-road vehicles, the EPA turned its attention to non-road engines, which also contribute significantly to air pollution. Diesel engines, also referred to as compression-ignition engines, dominate the large non-road engine market. Examples of non-road equipment that use diesel engines include: agricultural equipment such as tractors, balers, and combines; construction equipment such as backhoes, graders, and bulldozers; general industrial equipment such as concrete/industrial saws, crushing equipment, and scrubber/sweepers; lawn and garden equipment such as garden tractors, rear engine mowers, and chipper/grinders; material handling equipment such as heavy forklifts; and utility equipment such as generators, compressors, and pumps.

The EPA adopted regulations in 40 Code of Federal Regulations Part 89 (40 CFR 89), Control of Emissions from New and In-use Nonroad Engines, effective June 17, 1994. Under 40 CFR 89, diesel engines greater than 50 horsepower (hp) must comply with Tier 1 emissions standards that were phased in between calendar years 1996 and 2000, depending on the size of the engine. Under the Tier 1 standards, the EPA projects that NO_x emissions from new non-road diesel equipment will be reduced by over 30% from uncontrolled levels of unregulated engines. The Tier 1 standards do not apply to engines used in underground mining equipment, locomotives, and marine vessels. The Mine Safety and Health Administration is responsible for setting requirements for underground mining equipment. Locomotives and marine vessels are covered by separate EPA programs.

Effective October 23, 1998, the EPA revised 40 CFR 89 and adopted more stringent emission standards for NO_x, non-methane hydrocarbons (NMHC), and particulate matter (PM) for new non-road diesel engines. Engines used in underground mining equipment, locomotives, and marine vessels over 50 hp are not included. This comprehensive new program phases in more stringent Tier 2 standards for all engine sizes from the model years 2001 to 2006, and yet more stringent Tier 3 standards from the model years 2006 to 2008. The following figure, which was extracted from the Table 1-1 of the "Final Regulatory Impact Analysis: Control of Emissions from Non-road Diesel Engines," (EPA 420-R-98-016, dated August 1998) shows the emission standards adopted by EPA in 40 CFR §89.112. Also, the new program includes a voluntary program called the "Blue Sky Series" engine program to encourage the production of advanced, very low-emitting engines. Under these new standards, the EPA projects that emissions from new non-road diesel equipment will be further reduced by 60% for NO_x and 40% for PM compared to the emission levels of engines meeting the Tier 1 standards.

Figure 1: 30 TAC Chapter 117 - Preamble

Emission Standards In grams per kilowatt-hour (g/kW-hr) and grams per horsepower-hour (g/hp-hr)					
Engine Power	Tier	Model Year	Non-Methane Hydrocarbons plus NO_x	Carbon Monoxide	Particulate Matter
kW < 8 (hp < 11)	Tier 1	2000	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	Tier 2	2005	7.5 (5.6)	8.0 (6.0)	0.80 (0.60)
8 ≤ kW < 19 (11 ≤ hp < 25)	Tier 1	2000	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	Tier 2	2005	7.5 (5.6)	6.6 (4.9)	0.80 (0.60)
19 ≤ kW < 37 (25 ≤ hp < 50)	Tier 1	1999	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	Tier 2	2004	7.5 (5.6)	5.5 (4.1)	0.60 (0.45)
37 ≤ kW < 75 (50 ≤ hp < 100)	Tier 2	2004	7.5 (5.6)	5.0 (3.7)	0.40 (0.30)
	Tier 3	2008	4.7 (3.5)	5.0 (3.7)	
75 ≤ kW < 130 (100 ≤ hp < 175)	Tier 2	2003	6.6 (4.9)	5.0 (3.7)	0.30 (0.22)
	Tier 3	2007	4.0 (3.0)	5.0 (3.7)	
130 ≤ kW < 225 (175 ≤ hp < 300)	Tier 2	2003	6.6 (4.9)	3.5 (2.6)	0.20 (0.15)
	Tier 3	2006	4.0 (3.0)	3.5 (2.6)	
225 ≤ kW < 450 (300 ≤ hp < 600)	Tier 2	2001	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)
	Tier 3	2006	4.0 (3.0)	3.5 (2.6)	
450 ≤ kW ≤ 560 (600 ≤ hp ≤ 750)	Tier 2	2002	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)
	Tier 3	2006	4.0 (3.0)	3.5 (2.6)	
kW > 560 (hp > 750)	Tier 2	2006	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)

While the EPA has addressed highway (on-road) and non-road engines, stationary diesel engines have yet to be addressed at the federal level. The proposed Chapter 117 rules will subject new and existing stationary diesel engines in HGA which operate at least 100 hours per year to emission specifications of either 11 grams per horsepower hour (g/hp-hr) (the estimated uncontrolled level) for existing engines or the Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of installation of new engines or modification, reconstruction, or relocation of existing engines. This will ensure that as turnover of older, higher-emitting stationary diesel engines occurs, the replacements will be cleaner engines. Dual-fuel engines at minor sources in HGA will be subject to an emission specification of 5.83 g/hp-hr (the estimated uncontrolled level) to address engines which are both gas- and diesel-fired. In addition, new and existing stationary diesel engines in HGA which operate at least 100 hours per year will be subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, concerning Mass Emissions Cap and Trade Program, if they are located at a site where the collective design capacity to emit NO_x is at least ten tons per year (tpy).

New stationary diesel engines which operate less than 100 hours per year will be required to meet the Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of installation, while existing stationary diesel engines which operate less than 100 hours per year but are modified, reconstructed, or relocated will be required to meet the Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of modification, reconstruction, or relocation. Existing stationary diesel engines, if used exclusively in emergency situations, will continue to be exempt from the new emission specifications, but new, modified, reconstructed, or relocated stationary diesel engines placed into service on or after October 1, 2001 will be required to meet the Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of installation, modification, reconstruction, or relocation. This will ensure that as turnover of older, higher-emitting stationary diesel engines occurs, the replacements will be cleaner engines.

Ozone is formed through chemical reactions between natural and man-made VOC and NO_x emissions in the presence of sunlight. The critical time for the mixing (chemical reactions) of NO_x and VOC is early in the day, and thus, higher ozone levels occur most frequently on hot summer afternoons. By delaying the hours of operation of stationary diesel and dual-fuel engines for testing and maintenance, and delaying the release of NO_x emissions until after noon in HGA, the NO_x emissions are less likely to mix in the atmosphere with other ozone-forming compounds until after the critical mixing time has passed. Therefore, production of ozone will be stalled until later in the day when optimum ozone formation conditions no longer exist, ultimately minimizing the peak level of ozone produced. This strategy is not dependent on atmospheric conditions to reduce ozone formation, as such strategies are disfavored by 42 USC, §7423. Instead, the strategy creates reductions in the amount of NO_x added to the atmosphere by stationary diesel and dual-fuel engines during the time of day when those emissions have been shown to contribute to exceedances of the ozone NAAQS. The use of "time of day" restrictions such as this for NAAQS compliance strategies was supported by the EPA in their non-road mobile source rules. Consequently, the proposed amendments will prohibit stationary diesel and dual-fuel engines in HGA from being started or operated for testing or maintenance between the hours of 6:00 a.m. and noon, beginning April 1, 2002.

SECTION BY SECTION DISCUSSION

The primary purpose of the proposed amendments to Chapter 117 and revisions to the SIP is to establish new emission specifications and operating restrictions for stationary diesel and dual-fuel engines for the HGA ozone attainment demonstration. The current NO_x reasonably available control technology (RACT) limits in §117.105 and §117.205, concerning Emission Specifications for

Reasonably Available Control Technology (RACT), apply to certain boilers, process heaters, and stationary engines and stationary gas turbines. The proposed revisions will establish emission reduction requirements for stationary diesel engines which are currently exempt from the NO_x RACT limits in §117.105 and §117.205, as well as from the emission specifications for attainment demonstrations in §117.106 and §117.206. The proposed amendments would also require new stationary gas turbines and duct burners at minor sources of NO_x in HGA to meet emission specifications in order to reduce NO_x emissions and ozone air pollution. In addition, the proposed amendments would improve implementation of the existing Chapter 117 by correcting typographical errors, updating cross-references, clarifying ambiguous language, adding flexibility, amending requirements to achieve the intended emission reductions of the program, and deleting the exemption for small (10 MW or less) electric generating units which are registered under a standard permit. Finally, the proposed amendments would revise the ESADs for electric utilities and landfill gas-fired stationary engines, revise the emission reduction schedule for sources other than electric utilities, and provide for alternate ESADs in the event that the TNRCC's continuing scientific assessment of the causes of and possible solutions to HGA's ozone nonattainment status results in a determination that attainment can be reached with fewer NO_x emission reductions from point sources concurrent with additional emission reduction strategies.

The proposed changes to §117.10, concerning Definitions, add definitions of "diesel engine," "emergency situation," and “pyrolysis reactor” and renumber subsequent definitions to accommodate the proposed new definitions. The amendments to §117.10 also revise the definition of “electric generating facility (EGF)" in order to clarify that this definition includes an out-of-state owner that does business in Texas.

In addition, the proposed changes to §117.10 revise the definition of "electric power generating system" to clarify that in HGA, industrial cogeneration units and units owned by independent power producers are subject to §117.210, concerning System Cap, and to bring stationary diesel engines into this system cap for consistency with the proposed changes to §117.210, described later in this preamble. As a result of the proposed changes to the definition of "electric power generating system," the commission is proposing revisions to the emissions banking and trading program of Chapter 101, Subchapter H, Division 3, being noticed for public hearings and comment concurrently in this issue of the *Texas Register*. Specifically, the proposed amendments to the figure in §101.353(a), concerning Allocation of Allowances, would revise variable (3)(A) of the reduction factor equation by changing a reference from "§117.10" to a more complete reference to "§117.10(13)(A)(iii)" in order to ensure that non-electric utility EGFs (for example, industrial cogeneration units and units owned by independent power producers) remain on the same compliance schedule as other non-electric utility sources.

The proposed changes to §117.10 also add the word "and" to the definitions of "large DFW system" and "small DFW system" in order to improve the readability of these definitions.

Finally, the proposed changes to §117.10 also revise the definition of "unit" to broaden its applicability. Currently, this definition includes stationary sources of NO_x at major sources. Because Subchapter D, Division 2, concerning Boilers, Process Heaters, and Stationary Engines at Minor Sources, applies to stationary sources of NO_x at minor sources, the amendments broaden the applicability of the definition of unit to include boilers, process heaters, stationary gas turbines, and stationary engines at minor sources. The current Subchapter D, Division 2, applies to boilers, process heaters, and stationary engines. As noted elsewhere in this preamble, the proposed changes will establish new requirements in Subchapter D, Division 2, for stationary gas turbines, so it is necessary to include stationary gas turbines in the definition of unit as it applies to minor sources.

The proposed changes to §117.101, concerning Applicability, revise §117.101(a) to update a reference to the renumbered §117.10(13); and add a new §117.101(4) to clearly specify that duct burners in gas turbine exhaust ducts are included in the applicability of Subchapter B, Division 1 (Utility Electric Generation in Ozone Nonattainment Areas). This will ensure that emissions from a duct burner are subject to the same ESAD in HGA as the associated gas turbine of which the duct burner is an integral part. The new §117.101(4) will only affect units in HGA because §117.106, concerning Emission Specifications for Attainment Demonstrations, does not apply to gas turbines in the Beaumont/Port Arthur (BPA) or Dallas/Fort Worth (DFW) ozone nonattainment areas. Further, although §117.105, concerning Emission Specifications for Reasonably Available Control Technology (RACT), applies to gas turbines in BPA or DFW, §117.103(a)(1) exempts "any new units placed into service after November 15, 1992." The installation of duct burners is a relatively recent phenomenon, and the commission is unaware of any duct burners that were placed into service before November 15, 1992.

The proposed change to §117.103, concerning Exemptions, deletes the exemption for small (10 MW or less) electric generating units which are registered under a standard permit. At the time of adoption of this exemption on December 6, 2000, the proposed standard permit for small electric generating units (November 2000) contained output-based emission limits at least as clean as new central power plants, thereby having a minimal impact on the HGA Attainment Demonstration SIP. Subsequently, the commission has received information that applying output-based emission limits at this level to small electric generating units may not be feasible because of differences in operating efficiency between small (10 MW and less) and larger electric generating units. Therefore, the commission believes it is necessary to delete the exemption to ensure that there is no impact of NO_x emissions on HGA.

The proposed changes to §117.106, concerning Emission Specifications for Attainment Demonstrations, revise §117.106(c)(1)(A) to change the ESAD in HGA for gas-fired utility boilers from 0.010 pound per million British thermal units (lb/MMBtu) to 0.020 lb/MMBtu; and revise §117.106(c)(1)(B) to change the ESAD in HGA for coal-fired or oil-fired utility boilers from 0.030 lb/MMBtu to 0.040 lb/MMBtu. The proposed changes have the effect of reducing the emission reduction requirement for the major HGA electric utility from 93% to 90%, based on its peak 30-day NO_x emissions in 1998. The proposed changes would similarly reduce the percentage reduction required of the other Public Utility Commission (PUC)-regulated electric utility in HGA.

The point source NO_x control strategy as adopted on December 6, 2000 had an associated NO_x emission reduction of 595 tpd. While the proposed revisions to the point source NO_x rules are now expected to reduce NO_x by 586 tpd, the effect of this increase is counterbalanced by reductions enacted by the Texas Legislature requiring the permitting of grandfathered facilities in east and central Texas. The Legislature requires certain grandfathered sources in this region to reduce emissions of NO_x by approximately 50%. Because the legislation was finalized only a few days before this proposed SIP revision was brought before the commission, it has not been possible to perform a detailed modeling analysis to determine the equivalence of the regional reductions with the local increase. However, the commission believes that the current proposal will provide similar air quality benefits to the December 6, 2000 SIP revision for several reasons. First, NO_x emissions in east and central Texas will be significantly lower overall under the current SIP than under the December 6, 2000 SIP revision. Second, ozone production efficiency at the sources affected by the recent legislation is expected to be very high, based on recently published results from an ozone study conducted in the Nashville, Tennessee area by the Southern Oxidant Study. Results from the Texas 2000 Air Quality Study indicate that ozone production at Reliant's W. A. Parish power plant is three to five times lower than what is expected from the rural grandfathered sources. No data is currently available on ozone production efficiency at other Reliant units, but it is expected to be somewhat higher than that at the Parish facility. Third, the increased NO_x emissions will occur at peaking units, which generate most of their emissions in the afternoon, at least during the ozone season. Modeling has shown that afternoon emissions are less important in ozone formation than are morning emissions (at least for construction and lawn-care activities).

In any case, the proposed revised ESAD is cost effective in terms of cost per ton of NO_x compared to the ESADs in the December 6, 2000 SIP revision, and result in a very large reduction in emissions. Detailed modeling will be required to quantitatively assess the overall effect of these two compensating changes to the emissions inventory. The commission will address this issue during the first phase of the mid-course review.

In addition, the proposed changes to §117.106 revise §117.106(c) to clarify that "the lower of any applicable permit limit" refers to limits in any permit issued or application deemed administratively complete before January 2, 2001 or any limit in a permit by rule under which construction commenced by January 2, 2001.

The proposed changes to §117.106 also revise §117.106(c)(3) to clearly specify that duct burners in gas turbine exhaust ducts are subject to the same ESAD as stationary gas turbines. This is consistent with the new §117.101(4) for duct burners described earlier in this preamble.

Further, the proposed changes to §117.106 add a new §117.106(c)(5) which specifies that if, and to the extent supported by, the commission's continuing scientific assessment of the causes of and possible solutions to HGA's ozone nonattainment status results in a determination that attainment can be reached with fewer NO_x emission reductions from point sources concurrent with additional emission reduction strategies, then the executive director will develop a SIP revision involving revisions to the utility and non-utility ESADs for consideration at a commission agenda no later than June 1, 2002. In the event that the total NO_x emission reductions from utility and non-utility point sources required for attainment is determined to be 80% from the 1997 emissions inventory baseline, the revised specifications shall be the lower of any applicable permit limit in a permit issued or application deemed administratively complete before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the specifications in the subparagraphs of the section. The commission reserves all rights to assign any additional NO_x reduction benefits supported by the science evaluation to the relief of other control measures, including further NO_x point source relief.

As has been EPA's legal position since 1975 and TNRCC's policy, the SIP can be revised to adjust requirements, based upon new information, technology, or science, provided the ultimate goal of the SIP is achieved and all requirements of the federal act are met. The mid-course review is a well defined approach that incorporates this policy. In order to ensure that the HGA area is in attainment by 2007 and that the controls to get there are the most cost effective technology-based solutions possible, the commission has committed to performing a mid-course review (see the commission's enforceable commitment adopted in April 2000). The mid-course review process has already begun and will continue, ultimately resulting in a SIP revision submitted to EPA by May 1, 2004. There are planned opportunities throughout the process, as described in the SIP, to incorporate the latest information and make decisions. This effort will involve a thorough evaluation of all modeling, inventory data, and other tools and assumptions used to develop the attainment demonstration. It will also include the ongoing assessment of new technologies and innovative ideas to incorporate into the plan. For example, the commission is committed to developing an effective plan to minimize releases of reactive hydrocarbon emissions and the emissions of chlorine. To the extent that the science confirms the benefit from this program, then it is the intent of the commission to implement such a program through a SIP revision which will first offset NO_x reductions from industrial sources down to the 80% (535 tpd) level. The commission, in its discretion, may allocate any additional benefit beyond 80% to other SIP strategies and/or to the point source NO_x control strategy. Based upon current analysis, this 80% from utility and non-utility sources would result in a total reduction of not less than 535 tpd NO_x emissions from industrial sources in the HGA area.

The alternate ESADs proposed in §117.106(c)(5)(A)(C) were provided by the BCCA Appeal Group as part of the proposed "Consent Order" to be submitted to the 250th Travis County District Court in the lawsuit styled BCCA Appeal Group, et al v. TNRCC upon final approval of the parties in the lawsuit.

The NO_x control levels in the alternate ESADs for different NO_x point sources vary by source, but are intended to achieve an overall NO_x point source reduction of 535 tpd, which is an approximate 80% reduction from the 1997 emission point source inventory of 668 tpd. The alternate ESADs also include a new category, pyrolysis reactors, that was previously included within the category of process heaters. This agreed reduction, which is contingent upon the outcome of the science evaluation discussed elsewhere in this proposal, is proposed for public comment as a part of that agreement. The commission hereby solicits public comment on the BCCA Appeal Group alternate ESADs proposed in this rule, from all interested persons, including all owners and operators of NO_x point sources and other stakeholders who are not members of the BCCA Appeal Group. The commission reserves all rights to assign any additional NO_x reduction benefits supported by the science evaluation to the relief of other control measures, including further NO_x point source relief.

In addition, the proposed changes to §117.106 delete the word "boiler," which is a typographical error, in §117.106(d), and correct the references in §117.106(a) and (e)(1)(B) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)).

Finally, the proposed changes to §117.106 revise §117.106(e)(4) by deleting the superfluous word "alternative" and allowing owners or operators of EGFs in the HGA ozone nonattainment area who are required to participate in a system cap under §117.108 to trade emissions with other participating owners or operators of EGFs in the same ozone nonattainment area under the requirements of Chapter 101, Subchapter H, Division 1, 4, or 5, concerning Emission Credit Banking and Trading; Discrete Emission Credit and Trading Program; and System Cap Trading. The proposed change will give the owners and operators of EGFs in HGA additional flexibility in meeting their system caps either through the use of emission reduction credits (ERCs), discrete emission reduction credits (DERCs), or through the transfer of emission allowables among EGFs participating in a system cap that are in the same nonattainment area. This flexibility is already available in DFW.

The proposed change to §117.107, concerning Alternative System-wide Emission Specifications, revises §117.107(a) to update a reference to the renumbered §117.10(13).

The proposed changes to §117.108 and §117.138, concerning System Cap, revise §117.108(b) and §117.138(b) to update references to the renumbered §117.10(13). The proposed changes to §117.108 also make revisions within the figure in §117.108(c)(1) to specify January 2, 2001 as the cutoff for administratively complete permit applications under Chapter 116 and start of construction of EGFs under a Chapter 106 permit by rule. This date is consistent with §101.353. The proposed changes within the figure in §117.108(c)(1) also revise the system cap for EGFs in the definition, H_i (B)(i), by allowing the owner or operator to choose any consecutive 30-day period within the third quarter, rather than the system highest 30-day period. This option is also reflected in the definition of H_i (B)(ii). This change will provide flexibility to systems which include both coal- and gas-fired units.

The proposed change to §117.109, concerning System Cap Flexibility, allows owners or operators of EGFs in the BPA and HGA ozone nonattainment areas who are participating in a system cap under §117.108 to trade emissions with other participating owners or operators of EGFs in the same ozone nonattainment area under the requirements of Chapter 101, Subchapter H, Division 1, 4, or 5. The proposed change will give the owners and operators of EGFs in BPA and HGA additional flexibility in meeting their system caps either through the use of ERCs, DERCs, or through the transfer of emission allowables among EGFs participating in a system cap that are in the same nonattainment area. This flexibility is already available in DFW.

The proposed change to §117.110, concerning Change of Ownership - System Cap, clarifies the impact of a change of ownership on a system cap. The current rule language states that in the event that a unit of an electric power generating system is sold or transferred, the unit shall become subject to the transferee's emission cap. The proposed change will clarify that sentence regarding the value R_i in §117.108(c) based on the unit's status as part of a large or small system as of January 1, 2000 is specific to electric power generating systems in DFW (either a large DFW system, or small DFW system, as defined in §117.10).

The proposed changes to §117.119, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.119(b) and (c) to more accurately direct testing results and notifications of initial demonstration of compliance testing to the proper agency and local program representatives. Specifically, the revisions to §117.119(b) specify that verbal notification of initial demonstration of compliance testing and continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) performance evaluation should be made to the appropriate regional office and any local air pollution control agency having jurisdiction, rather than the executive director. In addition, the revisions to §117.119(c) specify that a copy of the initial demonstration of compliance testing should be provided to the Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction, rather than the executive director. Any testing results sent to the Office of Compliance and Enforcement should include the notation "Engineering Services Team (MC 171)" to help ensure accurate mail delivery.

The proposed changes to §117.203, concerning Exemptions, add a reference to the new §117.206(i) described later in this preamble to make all stationary diesel and dual-fuel engines in HGA subject to the maintenance and testing operating schedule restrictions; add a reference to the final control plan requirements of §117.216(a)(5) for units claimed exempted from the emission specifications; and add references to the run time meter and recordkeeping requirements of §§117.213(i), 115.214(a)(2), and 117.219(f)(6) for units exempted from the emission specifications due to low annual hours of operation.

In addition, the proposed changes to §117.203 replace the existing exemption in §117.203(a)(6)(A) for stationary gas turbines and engines operated exclusively for firefighting and/or flood control with an exemption for stationary gas turbines and engines used exclusively in emergency situations, as defined in the proposed new §117.10(14). However, operation for testing or maintenance purposes would be allowed for up to 52 hours per year, based on a rolling 12-month average. Fifty-two hours per year would allow up to one hour per week of maintenance or testing, which is a reasonable upper bound for this type of operation. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service in HGA on or after October 1, 2001 is ineligible for this exemption. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in 40 CFR §60.14 and §60.15, respectively. New and existing engines will continue to be eligible for exemption under §117.203(a)(6) if they are used for one or more of the following purposes: research and testing; performance verification and testing; solely to power other engines or gas turbines during start-ups; in response to and during the existence of any officially declared disaster or state of emergency; or directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals. The net effect is that existing stationary diesel and dual-fuel engines, if used exclusively in emergency situations, will continue to be exempt from the new emission specifications, but new, modified, reconstructed, or relocated stationary diesel engines placed into service on or after October 1, 2001 will be required to be cleaner diesel engines. Specifically, these new, modified, reconstructed, or relocated stationary diesel engines will be required to meet the federal Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of installation, modification, reconstruction, or relocation.

The proposed changes to §117.203 also delete a redundant exemption in §117.203(a)(6)(B) for operation of stationary gas engines and turbines which operate less than 850 hours per year. An exemption for these sources in the BPA and DFW ozone nonattainment areas is available under §117.205(h)(9) and the revised §117.206(g)(2) (described later in this preamble). An exemption from

RACT is likewise available for these sources in HGA under §117.205(h)(9), but there is no exemption from the ESADs in HGA for stationary gas engines and turbines which operate less than 850 hours per year. Consequently, deletion of §117.203(a)(6)(B) will not result in additional requirements in BPA, DFW, or HGA.

In addition, the proposed changes to §117.203 revise §117.203(a)(10) for consistency with the proposed definition of "diesel engine" and make it specific to engines in BPA and DFW due to the new emission requirements for diesel engines in HGA.

The proposed changes to §117.203 further add a new §117.203(a)(11) to exempt existing stationary diesel engines in HGA (specifically, those placed into service before October 1, 2001) which operate less than 100 hours per calendar year, based on a rolling 12-month average. The new §117.203(a)(11) excludes any modified, reconstructed, or relocated engine placed into service on or after October 1, 2001. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in 40 CFR §60.14 and §60.15, respectively.

The proposed changes to §117.203 also add a new §117.203(a)(12) for new, modified, reconstructed, or relocated stationary diesel engines placed into service in HGA after October 1, 2001 which operate less than 100 hours per calendar year, based on a rolling 12-month average. To qualify for this exemption, the engine must meet the EPA's Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines listed in 40 CFR §89.112(a), Table 1 and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in 40 CFR §60.14 and §60.15, respectively.

In addition, the proposed changes to §117.203 also revise §117.203(b) to eliminate the reference to the exemption in §117.203(a)(6)(B) which, as described earlier in this preamble, is being deleted because it is redundant.

Finally, the proposed changes to §117.203 delete the exemption in §117.203(c) for small (10 MW or less) electric generating units which are registered under a standard permit. At the time of adoption of this exemption on December 6, 2000, the proposed standard permit for small electric generating units (November 2000) contained output-based emission limits at least as clean as new central power plants, thereby having a minimal impact on the HGA Attainment Demonstration SIP. Subsequently, the commission has received information that applying output-based emission limits at this level to small electric generating units may not be feasible because of differences in operating efficiency between small (10 MW and less) and larger electric generating units. Therefore, the commission believes it is necessary to delete the exemption to ensure that there is no greater impact of NO_x emissions on HGA.

According to a comment received during previous rulemaking, emergency generators usually do not operate more than 100 hours per year. (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 585)). However, engines which are used to shave peak electric demand tend to operate on hot days that coincide with higher probability of ozone exceedances. Therefore, it is necessary to establish emission specifications for these engines and include them in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3.

The proposed changes to §117.206, concerning Emission Specifications for Attainment Demonstrations, revise §117.206(c) to clarify that "the lower of any applicable permit limit" refers to limits in any permit issued or application deemed administratively complete before January 2, 2001, or any limit in a permit by rule under which construction commenced by January 2, 2001 and revise §117.206(c)(2)(B), (3)(B)(ii), and (16)(A) to clarify that a consistent methodology must be used for the ESADs for fluid catalytic cracking units (FCCUs) (including carbon monoxide (CO) boilers, CO furnaces, and catalyst regenerator vents), boilers and industrial furnaces (BIF units), and incinerators which are based on a specific percent reduction from the emission factor used to calculate the June - August 1997 daily NO_x emissions. This is necessary to prevent an owner or operator from using an emission factor which overestimates the June - August 1997 daily NO_x emissions, using an emission factor which more accurately estimates the NO_x emissions, and then claiming credit for the resultant “paper” emission reductions without actually achieving the real emission reductions that the rule is intended to achieve. The proposed changes to §117.206(c)(2)(B), (3)(B)(ii), and (16)(A) are necessary because of, and are consistent with, the new §101.354(b), concerning Allowance Deductions, that the commission is proposing to add to the emissions banking and trading program of Chapter 101, Subchapter H, Division 3, being noticed for public hearings and comment concurrently in this issue of the *Texas Register*.

The proposed changes to §117.206 also revise §117.206(c)(9)(A) and (B) to establish an ESAD of 0.60 g NO_x/hp-hr for stationary engines which are fired on landfill gas. The existing ESADs of 0.17g

NO_x/hp-hr and 0.50 g NO_x/hp-hr for gas-fired rich-burn and lean-burn engines, respectively, are based on use of flue gas cleanup and are proposed to remain the ESADs for those engines not fired on landfill gas. However, it has come to the commission's attention that landfill gas contains siloxanes which rapidly poison the catalyst of flue gas cleanup controls. The revised ESAD for stationary engines which are fired on landfill gas is based upon combustion modifications and is necessary to ensure that the ESAD for these engines is technically feasible.

Additionally, the proposed changes to §117.206 add a new §117.206(c)(9)(D) which establishes emission specifications for stationary diesel engines which are based on the EPA's Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines listed in 40 CFR §89.112(a), Table 1. Because the Tier 2/Tier 3 standards and some of the Tier 1 standards are expressed in terms of NMHC + NO_x, the commission used Table 2 entitled Combined and Pollutant-Specific Emissions Standards for Nonroad Diesel Engines from *Exhaust Emission Factors for Nonroad Engine Modeling -- Compression Ignition, Report No. NR-009A*, (revised June 15, 1998) to split the combined NMHC+NO_x standards into single pollutant emission factors. While Table 2 notes that pollutant-specific components have no regulatory significance within the Tier 2/Tier 3 program and were derived to facilitate modeling analyses, it is necessary for Chapter 117 to use NO_x-specific values because the mass emissions cap and trade program of Chapter 101 cannot use emission specifications for multiple pollutants to establish allocations for a single pollutant (i.e., NO_x).

Figure 2: 30 TAC Chapter 117 - Preamble

Combined and Pollutant-Specific Emission Standards

In grams per kilowatt-hour (g/kW-hr) and grams per horsepower-hour (g/hp-hr)

Engine Power	Tier	Non-Methane Hydrocarbons plus NO_x	NMHC	NO_x
kW < 8 (hp < 11)	Tier 2	7.5 (5.6)	0.8 (0.6)	6.7 (5.0)
	Tier 3	---	----	----
8 ≤ kW < 19 (11 ≤ hp < 25)	Tier 2	7.5 (5.6)	0.8 (0.6)	6.7 (5.0)
	Tier 3	----	----	----
19 ≤ kW < 37 (25 ≤ hp < 50)	Tier 2	7.5 (5.6)	0.8 (0.6)	6.7 (5.0)
	Tier 3	----	----	----
37 ≤ kW < 75 (50 ≤ hp < 100)	Tier 2	7.5 (5.6)	0.5 (0.4)	7.0 (5.2)
	Tier 3	4.7 (3.5)	0.3 (0.2)	4.4 (3.3)
75 ≤ kW < 130 (100 ≤ hp < 175)	Tier 2	6.6 (4.9)	0.6 (0.4)	6.0 (4.5)
	Tier 3	4.0 (3.0)	0.3 (0.2)	3.7 (2.8)
130 ≤ kW < 225 (175 ≤ hp < 300)	Tier 2	6.6 (4.9)	0.6 (0.4)	6.0 (4.5)
	Tier 3	4.0 (3.0)	0.3 (0.2)	3.7 (2.8)
225 ≤ kW < 450 (300 ≤ hp < 600)	Tier 2	6.4 (4.8)	0.4 (0.3)	6.0 (4.5)
	Tier 3	4.0 (3.0)	0.3 (0.2)	3.7 (2.8)
450 ≤ kW ≤ 560 (600 ≤ hp ≤ 750)	Tier 2	6.4 (4.8)	0.4 (0.3)	6.0 (4.5)
	Tier 3	4.0 (3.0)	0.3 (0.2)	3.7 (2.8)
kW > 560 (hp > 750)	Tier 2	6.4 (4.8)	0.4 (0.3)	6.0 (4.5)
	Tier 3	----	----	----

Further, the proposed changes to §117.206 add a new §117.206(c)(18) which specifies that if, and to the extent supported by, the commission's continuing scientific assessment of the causes of and possible solutions to HGA's ozone nonattainment status results in a determination that attainment can be reached with fewer NO_x emission reductions from point sources concurrent with additional emission reduction strategies, then the executive director will develop a SIP revision involving revisions to the utility and non-utility ESADs for consideration at a commission agenda no later than June 1, 2002. In the event that the total NO_x emission reductions from utility and non-utility point sources required for attainment is determined to be 80% from the 1997 emissions inventory baseline, the revised specifications shall be the lower of any applicable permit limit in a permit issued or application deemed administratively complete before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the specifications in the subparagraphs of the section. The commission reserves all rights to assign any additional NO_x reduction benefits supported by the science evaluation to the relief of other control measures, including further NO_x point source relief.

As has been EPA's legal position since 1975 and TNRCC's policy, the SIP can be revised to adjust requirements, based upon new information, technology, or science, provided the ultimate goal of the SIP is achieved and all requirements of the federal act are met. The mid-course review is a well defined approach that incorporates this policy. In order to ensure that the HGA area is in attainment by 2007 and that the controls to get there are the most cost effective technology-based solutions possible, the commission has committed to performing a mid-course review (see the commission's enforceable commitment adopted in April 2000). The mid-course review process has already begun and will continue, ultimately resulting in a SIP revision submitted to EPA by May 1, 2004. There are planned opportunities throughout the process, as described in the SIP, to incorporate the latest information and make decisions. This effort will involve a thorough evaluation of all modeling, inventory data, and other tools and assumptions used to develop the attainment demonstration. It will also include the ongoing assessment of new technologies and innovative ideas to incorporate into the plan. For example, the commission is committed to developing an effective plan to minimize releases of reactive hydrocarbon emissions and the emissions of chlorine. To the extent that the science confirms the benefit from this program, then it is the intent of the commission to implement such a program through a SIP revision which will first offset NO_x reductions from industrial sources down to the 80% (535 tpd) level. The commission, in its discretion, may allocate any additional benefit beyond 80% to other SIP strategies and/or to the point source NO_x control strategy. Based upon current analysis, this 80% from utility and non-utility sources would result in a total reduction of not less than 535 tpd NO_x emissions from industrial sources in the HGA area.

The alternate ESADs proposed in §117.206(c)(18)(A) - (R) were provided by the BCCA Appeal Group as part of the proposed "Consent Order" to be submitted to the 250th Travis County District Court in the lawsuit styled BCCA Appeal Group, et al v. TNRCC upon final approval of the parties in the lawsuit.

The NO_x control levels in the alternate ESADs for different NO_x point sources vary by source, but are intended to achieve an overall NO_x point source reduction of 535 tpd, which is an approximate 80% reduction from the 1997 emission point source inventory of 668 tpd. The alternate ESADs also include a new category, pyrolysis reactors, that was previously included within the category of process heaters.

This agreed reduction, which is contingent upon the outcome of the science evaluation discussed elsewhere in this proposal is proposed for public comment as a part of that agreement. The commission hereby solicits public comment on the BCCA Appeal Group alternate ESADs proposed in this rule, from all interested persons, including all owners and operators of NO_x point sources and other stakeholders who are not members of the BCCA Appeal Group. The commission reserves all rights to assign any additional NO_x reduction benefits supported by the science evaluation to the relief of other control measures, including further NO_x point source relief.

The proposed changes to §117.206 also correct the reference in §117.206(f)(1)(C) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance" (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)), and revise §117.206(f)(4) to allow an owner or operator to use the alternative methods specified in §117.570 for purposes of complying with the EGF system cap in §117.210. The proposed change will give the owners and operators of EGFs in HGA additional flexibility in meeting their system caps.

In addition, the proposed changes to §117.206 revise §117.206(g)(2) by adding a reference to §117.205(h)(9) to ensure the continued availability of an exemption in BPA and DFW for stationary gas engines and turbines which operate less than 850 hours per year.

The proposed changes to §117.206 also revise §117.206(h) by clarifying the intent of existing language concerning units in HGA which combust fuel or waste streams containing chemical-bound nitrogen and by moving the existing language into a new §117.206(h)(3). A new §117.206(h)(1) adds language to prohibit an owner or operator in HGA from derating equipment to take advantage of a less stringent ESAD in §117.206(c). The proposed language would allow derating from the maximum rated capacity on December 31, 2000 provided the TNRCC had received an administratively complete permit application (as determined by the executive director) before January 2, 2001. If the owner or operator increased the rated capacity after December 31, 2000, the higher of the two ratings would be used to determine the applicability of the ESAD in §117.206(c).

The proposed changes to §117.206 also add a new §117.206(h)(2) to specify how units which can be classified as multiple unit types are treated for purposes of applying the ESADs. Specifically, 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 continue to be classified as a boiler for the purposes of Chapter 117. If a unit would qualify for an exemption from the emission specifications of this section except for also being classified as a unit for which this section includes an emission specification, then the unit shall continue to be subject to that emission specification, regardless of any changes made to the unit after December 31, 2000. For example, a sulfuric acid regeneration unit (which would otherwise qualify for exemption under §117.203(a)(4)) that is also authorized to operate as a BIF unit as of December 31, 2000 shall continue to be subject to the emission specification for BIF units, regardless of any changes made to the unit after December 31, 2000. The new §117.206(h)(2) is necessary to ensure that the intended emission reductions of the program are achieved.

The proposed changes to §117.206 also add a new subsection (i) which prohibits starting or operating any stationary diesel or dual-fuel engine in HGA for testing or maintenance between the hours of 6:00 a.m. and noon. This requirement will delay the emissions of NO_x, a key ozone precursor, until after noon in order to limit ozone formation.

The proposed changes to §117.210 concerning System Cap, add language in §117.210(a) to clarify that each EGF in the system cap is subject to the daily cap and appropriate 30-day cap of this section at all times and delete similar language in existing §117.210(c)(3). Additionally, the proposed changes to §117.210 delete the specific emission specifications in the term R_i (which appears in the figure in §117.210(c)(1)) and substitute a reference to the ESADs of §117.206(c). This change will add stationary diesel, gas-fired rich-burn, and gas-fired lean-burn engines to the list of equipment subject to the daily and 30-day system cap emission limitations for electric generating facilities (EGFs) at industrial, commercial, and institutional combustion sources in HGA. In addition, the proposed changes to §117.210 revise the term H_i in the figure in §117.210(c)(1) to specify January 2, 2001 as the cutoff for administratively complete permit applications under Chapter 116 and start of construction of EGFs under a Chapter 106 permit by rule. This date is consistent with §101.353.

The proposed changes to §117.210(c)(1) specify the calculation in this paragraph applies to a rolling 30-day average emission cap applicable during the months of July through September. The proposed changes to §117.210 also revise the rolling 30-day average system cap for non-utility EGFs to take into account those industrial cogeneration units which have a maximum heat input rate in months other than July through September by adding a new §117.210(c)(2) to specify how to calculate a rolling 30-day average emission cap applicable during all months other than July through September. The proposed change will allow the owner or operator to substitute the nine months comprising the highest three consecutive months in each year of the 1997 - 1999 period. The existing §117.210(c)(2) is renumbered to become a new §117.210(c)(3).

The proposed changes to §117.213, concerning Continuous Demonstration of Compliance, add a new §117.213(c)(1)(I) which requires installation of a CEMS or PEMS to measure NO_x from FCCUs in HGA. While the commission expects that NO_x emissions from these FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents) will ultimately be controlled through injection of a chemical reagent, and therefore would already be required under the existing §117.213(c) to install a CEMS or PEMS to measure NO_x, the proposed change is necessary to ensure that relatively large NO_x emissions from these sources are monitored for purposes of the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3.

The proposed changes to §117.213 also revise §117.213(i) to change a reference from §117.203(a)(6)(B) to §117.205(h)(2) due to the deletion of the redundant exemption in §117.203(a)(6)(B) for operation of stationary gas engines and turbines which operate less than 850 hours per year, and add a reference to §117.203(a)(11) and (12) due to the addition of these new exemptions based on low annual hours of operation. In addition, the proposed changes to §117.213 specify that any run time meter installed on or after October 1, 2001 must be non-resettable to improve enforceability of the limit on hours of operation under the exemptions. This change will prevent an owner or operator from resetting a run time meter, whether deliberate or inadvertent, and making the actual number of hours of operation difficult to verify.

The proposed change to §117.214, concerning Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration, adds a new §117.214(a)(2) which references the run time meter requirements of §117.213(i) for stationary diesel engines claimed exempt using the exemption of §117.203(a)(11) or (12). The existing language becomes §117.214(a)(1) as a result of the addition.

The proposed changes to §117.219, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.219(b) and (c) to more accurately direct testing results and notifications of initial demonstration of compliance testing to the proper agency and local program representatives. Specifically, the revisions to §117.219(b) specify that verbal notification of initial demonstration of compliance testing and CEMS or PEMS performance evaluation should be made to the appropriate regional office and any local air pollution control agency having jurisdiction, rather than the executive director. In addition, the revisions to §117.219(c) specify that a copy of the initial demonstration of compliance testing should be provided to the Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction, rather than the executive director. Any testing results sent to the Office of Compliance and Enforcement should include the notation "Engineering Services Team (MC 171)" to help ensure accurate mail delivery.

In addition, proposed changes to §117.219 add a new §117.219(f)(10) which requires records of each time a stationary diesel or dual-fuel engine in HGA is operated for testing and maintenance in order to ensure compliance with the proposed restriction on operating hours for testing and maintenance and revise §117.219(f)(6) to add a reference to the proposed new exemptions of §117.203(a)(11) or (12) for low-usage diesel engines described earlier in this preamble.

The proposed changes to §117.471, concerning Applicability, add stationary gas turbines and associated duct burners to the list of equipment subject to the requirements of Subchapter D, Division 2, at minor sources in HGA, and update a reference to this division to reflect its new title.

The proposed changes to §117.473, concerning Exemptions, revise §117.473(a) by updating a reference to Subchapter D, Division 2, to reflect its new title and adding a reference to §117.478(c) and §117.479(h) - (j) because these requirements apply to some engines which are otherwise exempt; revise §117.473(a)(2) by changing "engines" to "stationary engines" for clarification; and revise §117.473(a)(2)(A) by changing "50 hp or less" to "less than 50 hp" for consistency with the federal Tier 2/Tier 3 diesel engine standards.

In addition, the proposed changes to §117.473 replace the existing exemption in §117.473(a)(2)(E) for engines operated exclusively for firefighting and/or flood control with an exemption for engines used exclusively in emergency situations, as defined in the proposed new §117.10(14). However, operation for testing or maintenance purposes would be allowed for up to 52 hours per year, based on a rolling 12-month average. Fifty-two hours per year would allow up to one hour per week of maintenance or testing, which is a reasonable upper bound for this type of operation. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service in HGA on or after October 1, 2001 is ineligible for this exemption. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in 40 CFR §60.14 and §60.15, respectively. New and existing diesel engines will continue to be eligible for exemption under §117.473(a)(2) if they are used for one or more of the following purposes: research and testing; performance verification and testing; solely to power other engines or gas turbines during start-ups; in response to and during the existence of any officially declared disaster or state of emergency; or directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals. In addition, existing engines will be eligible for the exemption for use exclusively in emergency situations, as described earlier in this preamble.

The proposed changes to §117.473 also revise the existing §117.473(a)(2)(H), which exempts engines that operate less than 100 hours per calendar year, to exempt engines that operate less than 100 hours per year, based on a rolling 12-month average, for consistency with the proposed §117.203(a)(11) described earlier in this preamble. The proposed changes to §117.473(a)(2)(H) also exclude any modified, reconstructed, or relocated diesel engine placed into service on or after October 1, 2001. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in 40 CFR §60.14 and §60.15, respectively. In addition, the proposed changes to §117.473 delete the reference to §117.479(h) in §117.473(a)(2)(H) due to the addition of a reference to §117.479(h) in §117.473(a), as described earlier in this preamble.

The proposed changes to §117.473 also replace the existing exemption for diesel engines in §117.473(a)(2)(I) with an exemption for new, modified, reconstructed, or relocated stationary diesel engines placed into service in HGA after October 1, 2001 which operate less than 100 hours per calendar year, based on a rolling 12-month average. To qualify for this exemption, the engine must meet the EPA's Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines listed in 40 CFR §89.112(a), Table 1 and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in 40 CFR §60.14 and §60.15, respectively.

In addition, the proposed changes to §117.473 add a new §117.473(a)(3) that exempts stationary gas turbines rated at less than 1.0 MW which were in operation on or before October 1, 2001. This exemption is necessary because the ESAD (described later in this preamble) is based on combustion modifications (dry low-NO_x burners (DLN) or water injection) which are not available as retrofits for some older gas turbines rated at less than 1.0 MW. Since these combustion modifications are readily available for new gas turbines rated at less than 1.0 MW, the exemption only applies to these smaller units with an initial start of operation on or before October 1, 2001.

The proposed changes to §117.473 also delete the exemption in §117.473(c) for small (10 MW or less) electric generating units which are registered under a standard permit. At the time of adoption of this exemption on December 6, 2000, the proposed standard permit for small electric generating units (November 2000) contained output-based emission limits at least as clean as new central power plants, thereby having a minimal impact on the HGA Attainment Demonstration SIP. Subsequently, the commission has received information that applying output-based emission limits at this level to small electric generating units may not be feasible because of differences in operating efficiency between small (10 MW and less) and larger electric generating units. Therefore, the commission believes it is necessary to delete the exemption to ensure that there is no greater impact of NO_x emissions on HGA.

According to a comment received during previous rulemaking, emergency generators usually do not operate more than 100 hours per year. (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 585)). However, engines which are used to shave peak electric demand tend to operate on hot days that coincide with higher probability of ozone exceedances. Therefore, it is necessary to establish emission specifications for these engines and, if they are located at a site where the collective design capacity to emit NO_x is ten tons or more per year, include them in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3.

The proposed changes to §117.475, concerning Emission Specifications for Attainment Demonstrations, revise §117.475(a) and (b) to clarify that "any applicable permit limit" refers to any permit issued before January 2, 2001. The proposed changes to §117.475 also replace a reference in §117.475(b)(1) to boilers, process heaters, and engines with "unit" for consistency with the proposed revisions to the definition of this term in §117.10, and update a reference in the renumbered §117.475(c)(4) due to the addition of the new §117.475(c)(3).

The proposed changes to §117.475 also revise §117.475(c)(2) to establish an ESAD of 0.60 g NO_x/hp-hr for stationary engines which are fired on landfill gas. The existing ESAD of 0.50 g NO_x/hp-hr is based on the use of flue gas cleanup and is proposed to remain the ESAD for stationary engines not fired on landfill gas. However, it has come to the commission's attention that landfill gas contains siloxanes which rapidly poison the catalyst of flue gas cleanup controls. The revised ESAD for stationary engines which are fired on landfill gas is based upon combustion modifications and is necessary to ensure that the ESAD for these engines is technically feasible.

The proposed changes §117.475 also add a new §117.475(c)(3) which establishes an emission specification for dual-fuel engines. The existing §117.475(c)(3) becomes §117.475(c)(6) as a result of the previously discussed proposed revisions and the reference to paragraphs (1) - (2) is revised to reference the proposed paragraphs (1) - (5).

The proposed changes to §117.475 also add a new §117.475(c)(4) which establishes emission specifications for stationary diesel engines which are based on the EPA's Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines listed in 40 CFR §89.112(a), Table 1. Because the Tier 2/Tier 3 standards and some of the Tier 1 standards are expressed in terms of $NMHC+NO_x$, the commission used *Exhaust Emission Factors for Nonroad Engine Modeling - Compression Ignition, Report No. NR-009A*, (revised June 15, 1998) to split the combined $NMHC+NO_x$ standards into single pollutant emission factors.

In addition, the proposed changes to §117.475 add a new §117.475(c)(5) which establishes an ESAD of 0.15 lb NO_x per MMBtu heat input (about 42 parts per million by volume (ppmv), dry at 15% O_2) for stationary gas turbines and duct burners used in turbine exhaust ducts at minor sources of NO_x located within the HGA ozone nonattainment area. The proposed ESAD is consistent with the current RACT limit of 42 ppmv. It is anticipated that combustion modifications such as DLN or water injection will be necessary to achieve the proposed ESAD. Because neither DLN nor water injection are available on some older gas turbines rated at less than 1.0 MW, the ESAD does not apply to these smaller units if they have an initial start of operation on or before October 1, 2001.

The proposed changes to §117.478, concerning Operating Requirements, replace references in §117.478(a), (b), and (b)(3) to boilers, process heaters, and engines with "unit" for consistency with the proposed revision to the definition of this term in §117.10.

The proposed changes to §117.478 also add a new subsection (c) which prohibits starting or operating any stationary diesel or dual-fuel engine in HGA for testing or maintenance between the hours of 6:00 a.m. and noon. This requirement will delay the emissions of NO_x, a key ozone precursor, until after noon in order to limit ozone formation.

The proposed changes to §117.479, concerning Monitoring, Recordkeeping, and Reporting Requirements, replace references in §117.479(a)(1), (e), and (e)(1), (2), (5) and (6) to boilers, process heaters, and engines with "unit" for consistency with the proposed revision to the definition of this term in §117.10; revise §117.479(d) to update a reference to §117.534 to reflect its new title; and revise §117.479(h) to add a reference to §117.473(a)(2)(I) to require records of hours of operation for stationary diesel engines claimed exempt due to low annual hours of operation.

The proposed changes to §117.479 also add a new §117.479(i), which requires run time meters for stationary diesel engines claimed exempt due to low annual hours of operation, and add a new §117.479(j) which requires records of each time a stationary diesel or dual-fuel engine in HGA is operated for testing and maintenance in order to ensure compliance with the proposed restriction on operating hours for testing and maintenance.

The proposed changes to §117.510, concerning Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas, correct the references in §117.510(a)(2)(A)(ii)(II) and (b)(2)(A)(i)(II)(-b-) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)).

In addition, the proposed changes to §117.510 revise §117.510(c)(2)(A)(i) to clarify the intended meaning of "time of installation of emission controls" regarding emissions monitors. Specifically, the changes specify that if emission controls on a unit will consist of both flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) and combustion controls, then for the purpose of determining when emissions monitors must be installed, "time of installation" means the time of installation of flue gas cleanup.

The proposed changes to §117.510 also revise §117.510(c)(2)(B) by adding new clauses (i) and (ii) which specify the dates by which the owner or operator of EGFs in HGA must submit to the executive director the certification of level of activity, H_i, specified in §117.108. The new §117.510(c)(2)(B)(i) requires the owner or operator of EGFs in HGA to make this submission no later than June 30, 2001;

however, this date is consistent with §101.360, concerning Level of Activity Certification, and has been communicated to the two affected companies. The existing language in §117.510(c)(2)(B) becomes clause (iii) as a result of the proposed changes.

Additionally the percent reductions in now §117.510(c)(2)(B)(iii) (I) and (II) are proposed to be changed from 46% and 92% to 47% and 95%, respectively. The proposed changes reflect that a higher percentage of the required electric utility NO_x reduction of §117.106(c)(1) will be accomplished by 2004 if the total amount of required reduction by 2007 is reduced as proposed in §117.106(c)(1). The amount of reduction required of PUC-regulated utilities by 2004 remains unchanged. The major utility in HGA is currently implementing a plan which will achieve all but 5% of the required reduction in the area by 2004.

In addition, the proposed changes to §117.510 add a new §117.510(c)(2)(D) which specifies that the owner or operator must comply with the emission reduction requirements of the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 as soon as practicable, but no later than the appropriate dates specified in that program.

Also, the proposed changes to §117.510 add a new §117.510(c)(2)(E) which specifies the dates by which owners or operators of each EGF must comply with the requirements of §117.108 if alternate emission specifications are implemented under §117.106(c)(5).

The proposed changes to §117.520, concerning Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas, correct the reference in §117.520(a)(3)(A)(ii)(III) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)).

In addition, the proposed changes to §117.520 revise §117.520(c)(2)(A)(i) to correct a reference from "§117.114" to "§117.214" and add run time meters (for stationary diesel engines claimed exempt in HGA) to the compliance schedule, and clarify the intended meaning of “time of installation of emission controls” regarding emissions monitors. Specifically, the changes specify that if emission controls on a unit will consist of both flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) and combustion controls, then for the purpose of determining when emissions monitors must be installed, “time of installation” means the time of installation of flue gas cleanup.

The proposed changes to §117.520 also revise the compliance schedule for non-utility EGFs in §117.520(c)(2)(B)(iii). Currently, the rules include the following staged implementation schedule for compliance with the HGA ESADs. First, 44% of the total reductions required to comply with the ESADs are required by March 31, 2004, with the next 45% of the reductions required by March 31, 2005. The final reductions are required by March 31, 2007. The proposed changes to §117.520(c)(2)(B)(iii) will specify that 39% of the total reductions required to comply with the ESADs are required by March 31, 2004, and the next 28% of the reductions are required by March 31, 2005. The next 11% of the reductions are required by March 31, 2006, and the final reductions continue to be required by March 31, 2007. The proposed changes would require smaller annual reductions in emissions spread over a five-year period. The commission proposes this to allow the affected industries more options for planning and implementing incremental reductions in emissions. The proposed amendment would not affect the March 31, 2007 final compliance date nor would it increase final emission rates, and would still achieve the final emission reductions as required by the SIP.

Further, the proposed new §117.520(c)(2)(C) specifies an emission reduction schedule that would apply if the alternative emission specifications of §117.206(c)(18) are implemented.

In addition, the proposed changes to §117.520 delete an incorrect reference to non-EGFs in existing §117.520(c)(2)(D), proposed to become §117.520(c)(2)(E). This change is necessary because the owners or operators of EGFs and non-EGFs alike must comply with the emission reduction requirements of the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 as soon as practicable, but no later than the appropriate dates specified in that program. Also, the existing §117.520(c)(2)(C) is proposed to become §117.520(c)(2)(D).

Finally, the proposed changes to §117.520 add a new §117.520(c)(2)(F) which specifies the compliance schedule for the restrictions on hours of operation for testing or maintenance of stationary diesel and dual-fuel engines in HGA.

The proposed change to §117.534, concerning Compliance Schedule for Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources, revise §117.534(1)(A) and (2)(A) to add run time meters (for stationary diesel engines claimed exempt in HGA) to the compliance schedule, and clarify the intended meaning of "time of installation of emission controls" regarding emissions monitors. Specifically, the changes specify that if emission controls on a unit will consist of both flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) and combustion controls, then for the purpose of determining when emissions monitors must be installed, "time of installation" means the time of installation of flue gas cleanup. The proposed changes to §117.534 also add a new §117.534(1)(E) and (2)(D) which specify the compliance schedule for the restrictions on hours of operation for testing or maintenance of stationary diesel and dual-fuel engines in HGA. Finally, the proposed revisions would update the title of §117.534 and Subchapter D, Division 2, to reflect the addition of requirements for new stationary gas turbines at minor sources in HGA.

The proposed changes to §117.570, concerning Use of Emissions Credits for Compliance, create a new §117.570(b) to provide flexibility for owners or operators of EGFs which are subject to the system caps of §§117.108, 117.138, or 117.210. Specifically, the new §117.570(b) would allow an owner or operator to meet the emission control requirements of these system caps by complying with the requirements of Chapter 101, Subchapter H, Division 5 of this title (relating to System Cap Trading) or by obtaining an ERC, mobile emission reduction credit (MERC), DERC, or mobile discrete emission reduction credit (MDERC) in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title, unless there are federal or state regulations or permits under the same commission account number which contain a condition or conditions precluding such use.

The proposed changes to §117.570 also revise §117.570(a) to correct references to the titles of divisions in Chapter 101, Subchapter H; relocate the last sentence of §117.570(a) to a new §117.570(c); and reletter the existing §117.570(b) as §117.570(d).

PUBLIC UTILITY REGULATORY ACT DETERMINATION

As described earlier in this preamble, the commission proposes these revisions to Chapter 117 and the SIP in order to reduce NO_x emissions and demonstrate attainment in the HGA ozone nonattainment area. Accordingly, the commission makes the following determination, as required by the Public Utility Regulatory Act (PURA), Texas Utilities Code (TUC), §39.263(c)(1)(A) and (3): reductions of NO_x made in compliance with this rulemaking are hereby determined to be an essential component in achieving compliance with the NAAQS for ground-level ozone; and the amount and location of reductions of NO_x emissions resulting from this rulemaking are hereby determined to be consistent with the air quality goals and policies of the commission.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMIT PROGRAM

Chapter 117 is an applicable requirement under 30 TAC Chapter 122; 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 for each emission unit affected by the revisions to Chapter 117 at their site.

FISCAL NOTE: COSTS TO STATE AND LOCAL GOVERNMENT

John Davis, Technical Specialist with Strategic Planning and Appropriations, determined that for the first five-year period the proposed amendments are in effect, there will be fiscal implications, which are not anticipated to be significant, for units of state and local government located within the eight-county HGA ozone nonattainment area of Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties that own or operate stationary diesel or dual-fuel engines.

The proposed amendments would establish new emission specifications and operating restrictions for stationary diesel or dual-fuel engines located within the HGA ozone nonattainment area. Beginning April 1, 2002, starting or operating any stationary diesel or dual-fuel engine for testing or maintenance between the hours of 6:00 a.m. and noon would be prohibited. New stationary diesel engines purchased after October 1, 2001 will be required to meet EPA's more stringent Tier 1, 2, or 3 emission standards that are in effect at the time of installation. This rulemaking would also subject these engines to the mass emissions cap and trade program if they are operated over 100 hours per year and located at a site where the collective design capacity to emit NO_x is greater than ten tons per year. Existing stationary diesel engines would also be subject to these requirements if these engines are modified, reconstructed, or moved.

Existing stationary diesel engines which are used exclusively in emergency situations, agricultural operations, and engines rated at less than 50 hp at minor NO_x sources would be exempt from the provisions of these rules. A minor NO_x source is a stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit less than 25 tons of NO_x per year.

Examples of facilities and operations supported by affected stationary diesel engines include backup generators supporting data processing operations, water utilities, hospitals, nursing homes, large retail facilities, and buildings requiring backup power to elevators. There are also affected stationary diesel engines at operations such as rock crushers, sand and gravel plants, hot mix asphalt and concrete plants, and oil and gas drilling rigs.

The cost to comply with this rulemaking will be the cost difference between current engines and more expensive engines that meet Tier 1, 2, or 3 emission standards, the cost to purchase allowances for engines subject to the commission's emission cap and trade program, and the installation of run time meters on certain engines. Based on a vendor's cost sheet for emergency diesel engines, the additional cost of Tier 1 engines (over uncontrolled engines) for various engine ratings is as follows: 400 hp, $4,000 (8.3% increase in purchase price); 470 hp, $2,500 (4.6% increase in purchase price); and 1,340 hp, $10,000 (6.3% increase in purchase price). Based on a vendor's cost sheet for emergency diesel engines, the additional cost of Tier 2 engines (over uncontrolled engines) for various engine ratings is as follows: 335 hp, $1,900 (4.5% increase in purchase price); 400 hp, $4,500 (9.4% increase in purchase price); and 535 hp, $8,800 (14.4% increase in purchase price). The additional costs for Tier 3 engines are expected to be similar to those of Tier 2 engines.

The commission estimates that approximately 50 stationary diesel engines in the HGA that are owned and operated by units of state and local government will be affected by the proposed amendments. Assuming a ten-year life cycle for these engines and an annual turnover rate of 10%, approximately five of these engines per year would be replaced in order to meet the Tier 1, 2, or 3 standards. Based on an average additional cost of approximately $5,300 per engine, the total cost to units of state and local government to replace affected stationary diesel engines would be $26,500 per year.

Instead of purchasing a new engine, an owner could retrofit the older engine with a NO_x abatement or similar emission control system; however, the cost of the retrofit is anticipated to exceed the cost of a new engine. According to a vendor, it would cost between $40,000 to $80,000 to retrofit a older engine with a NO_x abatement system that would allow the engine to meet emission requirements. The total price for a new engine that would meet requirements would cost between $13,000 to $100,000 in most cases.

New stationary diesel engines at sites that are subject to the commission's emission cap and trade program would not be allocated any allowances (NO_x emissions in tons) prior to commencing operations. Owners and operators of these engines would have to purchase allowances (tons), which the commission estimated in a previous rulemaking to cost between $500 - $5,000 per ton, prior to operating affected engines. It is unknown how many existing engines, of the five engines estimated to be purchased each year, would be subject to the commission's cap and trade program.

Stationary diesel engines used less than 100 hours per year will be required to record the operating time with elapsed run time meters. Run time meters have been included as standard equipment on most stationary diesel engines since approximately 1972. For the estimated four stationary diesel engines owned and operated by units state and local government which are not already equipped with run time meters, the cost is estimated at $100 for each run time meter plus $100 for installation for a total cost of $200 per engine, a total cost of $800 for all four engines to comply with this rulemaking.

The proposed amendments would also establish an ESAD for stationary gas turbines and duct burners used in turbine exhaust ducts at minor sources of NO_x located within the HGA ozone nonattainment area. The proposed ESAD is 0.15 lb NO_x per MMBtu heat input (about 42 ppmv, dry at 15% O_2) and is consistent with the current RACT limit of 42 ppmv. It is anticipated that combustion modifications such as DLN or water or steam injection will be necessary to achieve the proposed ESAD. The proposed amendments would also require continuous monitoring of FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents).

The commission anticipates no additional costs to units of state and local government due to the new ESAD covering gas turbines, and the requirement for continuous monitoring at FCCUs, because there are no known gas turbines or FCCUs affected by the proposed amendments that are owned or operated by units of state and local government.

PUBLIC BENEFIT AND COSTS

Mr. Davis determined that for each year of the first five years the proposed amendments are in effect, the public benefit anticipated from enforcement of and compliance with the proposed amendments will be a reduction of public exposure to NO_x, VOC, carbon monoxide, and PM emitted from affected stationary diesel and dual-fuel engines; a reduction of public exposure to NO_x emitted from affected stationary gas turbines; a reduction of ground-level ozone in ozone nonattainment areas; and contribution toward demonstration of attainment with the ozone NAAQS.

The proposed amendments would establish new emission specifications and operating restrictions for stationary diesel or dual-fuel engines located within the HGA ozone nonattainment area, establish an ESAD for gas turbines and related duct burners, and require continuous monitoring of FCCUs.

Beginning April 1, 2002, starting or operating any stationary diesel or dual-fuel engine for testing or maintenance between the hours of 6:00 a.m. and noon would be prohibited. New stationary diesel engines purchased after October 1, 2001 will be required to meet EPA's more stringent Tier 1, 2, or 3 emission standards that are in effect at the time of installation. This rulemaking would also subject these engines to the mass emissions cap and trade program if they are operated over 100 hours per year and located at a site where the collective design capacity to emit NO_x is greater than ten tons per year. Existing stationary diesel engines would also be subject to these requirements if these engines are modified, reconstructed, or moved.

Existing stationary diesel engines which are used exclusively in emergency situations, agricultural operations, and engines rated at less than 50 hp at minor sources of NO_x would be exempt from the provisions of these rules.

Examples of facilities and operations supported by affected stationary diesel engines include backup generators supporting data processing operations, hospitals, nursing homes, large retail facilities, and buildings requiring backup power to elevators. There are also affected stationary diesel engines at operations such as rock crushers, sand and gravel plants, hot mix asphalt and concrete plants, and oil and gas drilling rigs.

The cost to comply with this rulemaking will be the cost difference between current engines and more expensive engines that meet Tier 1, 2, or 3 emission standards; the cost to purchase allowances for engines subject to the commission's emission cap and trade program; and the installation of run time meters.

The commission estimates that approximately 2,450 stationary diesel engines in the HGA that are owned and operated by individuals and businesses will be affected by the proposed amendments. Assuming a ten-year life cycle for these engines and an annual turnover rate of 10%, approximately 245 of these engines per year would be replaced in order to meet the Tier 1, 2, or 3 standards. Based on an average additional cost of approximately $5,300 per engine, the total annual cost to individuals and businesses to replace affected stationary diesel engines would be $1.3 million.

Instead of purchasing a new engine, an owner could retrofit the older engine with a NO_x abatement or similar emission control system; however, the cost of the retrofit is anticipated to exceed the cost of a new engine. According to a vendor, it would cost between $40,000 to $80,000 to retrofit a older engine with a NO_x abatement system that would allow the engine to meet emission requirements. The total price for a new engine that would meet requirements would cost between $13,000 to $100,000 in most cases.

New stationary diesel engines at sites that are subject to the commission's emission cap and trade program would not be allocated any allowances (NO_x emissions in tons) prior to commencing operations. Owners and operators of these engines would have to purchase allowances (tons), which the commission estimated in a previous rulemaking to cost between $500 - $5,000 per ton, prior to operating affected engines. It is unknown how many existing engines, of the 245 engines estimated to be purchased each year, would be subject to the commission's cap and trade program.

Stationary diesel engines used less than 100 hours per year will be required to record the operating time with elapsed run time meters. This requirement will not apply to engines which qualify for exemptions. Run time meters have been included as standard equipment on most stationary diesel engines since approximately 1972. For the estimated 200 stationary diesel engines owned and operated by individuals and businesses which are not already equipped with run time meters, the cost is estimated at $100 for each run time meter plus $100 for installation for a total cost of $200 per diesel engine, for a total one-time cost of $40,000 for all 200 diesel engines to comply with this rulemaking.

The proposed amendments would also establish an ESAD for stationary gas turbines and duct burners used in turbine exhaust ducts at minor sources of NO_x located within the HGA ozone nonattainment area. The proposed ESAD is 0.15 lb NO_x per MMBtu heat input (about 42 ppmv, dry at 15% O_2) and is consistent with the current RACT limit of 42 ppmv. It is anticipated that combustion modifications such as DLN or water or steam injection will be necessary to achieve the proposed ESAD.

Based upon an analysis of the 1997 emissions inventory and vendor information, the vast majority of the stationary gas turbines (including duct burners) in HGA are located at major sources of NO_x, and therefore are already regulated by the commission. It is anticipated that approximately three stationary gas turbines and any associated duct burners in HGA will be affected by the proposed amendments. Total annualized costs are estimated from cost tables A-2 and A-4 of the United States Department of Energy (U.S. DOE) document, *Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines*, dated November 5, 1999 (Contract No. DE-FC02-97CHIO877). It is estimated that the cost effectiveness will range from approximately $288 to $1,805 per ton of NO_x reduced. Using the U.S. DOE document, the total capital cost for turbines at minor sources of NO_x in HGA is approximately $570,000 to $1.2 million, with a total annual cost of $74,940 to $396,000 per year.

New stationary gas turbines and associated duct burners which are located at minor sources of NO_x will be subject to the proposed ESAD. New stationary gas turbines and associated duct burners would also be subject to the mass emissions cap and trade program if they are located at a site where the collective design capacity to emit NO_x is greater than ten tons per year. These stationary gas turbines and associated duct burners would not be allocated any allowances (NO_x emissions in tons) prior to commencing operations. Owners and operators of these stationary gas turbines and associated duct burners would have to purchase allowances (tons), which the commission estimated in a previous rulemaking to cost between $500 - $5,000 per ton, prior to operating affected stationary gas turbines and associated duct burners. It is unknown how many new stationary gas turbines and associated duct burners would be located at minor sources of NO_x and would also be subject to the commission's cap and trade program.

The proposed amendments would also require continuous monitoring of FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents). Based on an analysis of the 1997 emission inventory database, the proposed continuous monitoring of FCCUs will require at most 13 additional units to install and operate NO_x CEMS or PEMS. The commission estimates the initial cost of a CEMS which monitors NO_x, oxygen, and flow to be approximately $137,400 to $179,600, with total annual costs of $64,800 to $66,000, based upon *U.S. EPA's Continuous Emission Monitoring System Cost Model, Version 3.0, 1998*. Based on these figures, the total cost for the additional NO_x CEMS or PEMS would be $1.8 to $2.3 million, with a total annual cost of approximately $842,400 to $858,000. It should be noted that this cost model provides the initial costs (including capital and installation costs) and annual costs (operating costs) for a single CEMS installed to monitor emissions from one source at a plant. In the cost model's user manual, the EPA notes that the cost model is not intended for use in estimating the costs for multiple CEMS to monitor multiple sources at a plant. Simply multiplying the number of CEMS by the model's result will overestimate the total cost since some of the costs are not repeated with the addition of a second CEMS or more.

SMALL BUSINESS AND MICRO-BUSINESS ASSESSMENT

There will be adverse fiscal implications, which are not anticipated to be significant, for small and micro-businesses located in the HGA ozone nonattainment area as a result of implementing the proposed amendments. The proposed amendments would establish new emission specifications and operating restrictions for stationary diesel and dual-fuel engines located within the HGA ozone nonattainment area.

Beginning April 1, 2002, starting or operating any stationary diesel or dual-fuel engine for testing or maintenance between the hours of 6:00 a.m. and noon would be prohibited. New stationary diesel engines purchased after October 1, 2001 will be required to meet EPA's more stringent Tier 1, 2, or 3 emission standards that are in effect at the time of installation. These engines would also be subject to the mass emissions cap and trade program if they are operated over 100 hours per year and located at a site where the collective design capacity to emit NO_x is greater than ten tons per year. Existing stationary diesel engines would also be subject to these requirements if these engines are modified, reconstructed, or moved.

Examples of facilities and operations supported by affected stationary diesel engines include backup generators supporting data processing operations, water utilities, hospitals, nursing homes, large retail facilities, and buildings requiring backup power to elevators. There are also affected stationary diesel engines at operations such as rock crushers, sand and gravel plants, hot mix asphalt and concrete plants, and oil and gas drilling rigs.

Existing stationary diesel engines which are used exclusively in emergency situations, agricultural operations, and engines rated at less than 50 hp at minor sources of NO_x would be exempt from the provisions of these rules.

The commission estimates that many of the 2,450 privately-owned and operated stationary diesel engines affected by the proposed amendments are owned and operated by small or micro-businesses. The cost to comply with this rulemaking for small or micro-businesses will be the same as larger industries and includes the cost difference between current unregulated engines and more expensive engines that meet Tier 1, 2, or 3 emission standards; the cost to purchase allowances for engines subject to the commission's emission cap and trade program; and the installation of run time meters. Based on a vendor's cost sheet for emergency diesel engines, the average additional cost of Tier 1, 2, and 3 engines compared to the current uncontrolled engines is $5,300 per engine. Small or micro-businesses with affected equipment at sites subject to the commission's cap and trade program would be required to pay between $500 to $5,000 per allowance ton prior to operating the affected equipment.

Additionally, small or micro-businesses that operate stationary diesel engines less than 100 hours per year will be required to record the operating time with elapsed run time meters, at a cost of $200 for the purchase and installation of each meter.

The following is an analysis of the cost per employee for small or micro-businesses affected by the proposed amendments. Small and micro-business are defined as having fewer than 100 or 20 employees respectively. A small business with one affected engine would incur average costs of approximately $5,300 or $53 per employee. A micro-business with one affected engine would incur average costs of approximately $5,300 or $265 per employee. The overall cost per employee will vary depending on the number of engines and run time meters purchased, total allowances purchased, and the number of persons employed by an affected business.

The proposed amendments would also establish an ESAD for stationary gas turbines and duct burners used in turbine exhaust ducts at minor sources of NO_x located within the HGA ozone nonattainment area. Additionally, the proposed amendments would also require continuous monitoring of FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents).

The commission anticipates no additional costs to small or micro-businesses due to the new ESAD covering gas turbines and the requirement for continuous monitoring at FCCUs because there are no known gas turbines and FCCUs affected by the proposed amendments that are owned or operated by small or micro-businesses.

DRAFT REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed the rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and determined that the rulemaking meets the definition of a "major environmental rule" as defined in that statute. "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, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

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

The amendments to Chapter 117 will require emission reductions from stationary diesel and dual-fuel engines in the HGA ozone nonattainment area. The amendments will also require new stationary gas turbines and duct burners at minor sources of NO_x in HGA to meet emission specifications in order to reduce NO_x emissions and ozone air pollution. In addition, the amendments will improve implementation of the existing Chapter 117 by correcting typographical errors, updating cross-references, clarifying ambiguous language, adding flexibility, amending requirements to achieve the intended emission reductions of the program, and deleting the exemption for small (10 MW or less) electric generating units which are registered under a standard permit. Finally, the amendments will revise the ESADs for electric utilities and landfill gas-fired stationary engines, revise the emission reduction schedule for sources other than electric utilities, and provide for alternate ESADs in the event that the TNRCC's continuing scientific assessment of the causes of and possible solutions to HGA's ozone nonattainment status results in a determination that attainment can be reached with fewer NO_x emission reductions from point sources concurrent with additional emission reduction strategies. The rules are intended to protect the environment and reduce risks to human health and safety from environmental exposure and may have adverse effects on certain utilities, petrochemical plants, refineries, and other industrial, commercial, or institutional groups, and each group could be considered a sector of the economy. While the amendments are intended to protect the environment, the commission believes they may adversely affect in a material way stationary diesel and dual-fuel engines at sources in the HGA ozone nonattainment area with a potential to emit NO_x in amounts greater than or equal to ten tpy, as well as stationary diesel and dual-fuel engines at sources with a potential to emit NO_x in amounts less than ten tpy. These sources comprise sectors of the economy (including petroleum refineries, petrochemical plants, and electric generating plants) in a sector of the state. This is based on the analysis provided elsewhere in this preamble, including the discussion in the PUBLIC BENEFIT AND COSTS section. The remaining amendments in this rulemaking are intended to provide flexibility and clarify the commission's intent that the HGA ozone nonattainment area is able to demonstrate attainment and these amendments are not expected to adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

The amendments implement requirements of the FCAA, 42 USC, §7410. Under 42 USC, §7410, states are required to adopt a SIP which provides for "implementation, maintenance, and enforcement" of the primary NAAQS in each air quality control region of the state. While §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). It is true that 42 USC does require some specific measures for SIP purposes, such as the inspection and maintenance program, but those programs are the exception, not the rule, in the SIP structure of 42 USC. The provisions of 42 USC recognize that states are in the best position to determine what programs and controls are necessary or appropriate in order to meet the NAAQS. This flexibility allows states, affected industry, and the public, to collaborate on the best methods for attaining the NAAQS for the specific regions in the state. Even though 42 USC allows states to develop their own programs, this flexibility does not relieve a state from developing a program that meets the requirements of §7410. Thus, while specific measures are not generally required, the emission reductions are required. States are not free to ignore the requirements of §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 (1997). The intent of SB 633 was to require agencies to conduct a regulatory impact analysis (RIA) of extraordinary rules. These are identified in the statutory language as major environmental rules that will have a material adverse impact and will exceed a requirement of state law, federal law, or a delegated federal program, or are adopted solely under the general powers of the agency. With the understanding that this requirement would seldom apply, the commission provided a cost estimate for SB 633 that concluded "based on an assessment of rules adopted by the agency in the past, it is not anticipated that the bill will have significant fiscal implications for the agency due to its limited application." The commission also noted that the number of rules that would require assessment under the provisions of the bill was not large. This conclusion was based, in part, on the criteria set forth in the bill that exempted proposed rules from the full analysis unless the rule was a major environmental rule that exceeds a federal law. As discussed earlier in this preamble, 42 USC 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 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 the full RIA contemplated by SB 633. This conclusion is inconsistent with the conclusions reached by the commission in its cost estimate and by the Legislative Budget Board (LBB) in its fiscal notes. Because the legislature is presumed to understand the fiscal impacts of the bills it passes, and that presumption is based on information provided by state agencies and the LBB, the commission believes that the intent of SB 633 was only to require the full RIA for rules that are extraordinary in nature. While the SIP rules will have a broad impact, that impact is no greater than is necessary or appropriate to meet the requirements of the FCAA. For these reasons, rules adopted for inclusion in the SIP fall under the exception in Texas Government Code, §2001.0225(a), because they are required by federal law.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The adopted rules, which reduce ambient NO_x and ozone in HGA, will be submitted to the EPA as one of several measures of the required new attainment demonstrations. Section 7511a(f) requires any moderate, serious, severe, or extreme ozone nonattainment area to implement NO_x RACT, unless a demonstration is made that NO_x reductions would not contribute to or would not be necessary for attainment of the ozone standard. By policy, the EPA requires photochemical grid modeling to demonstrate whether the §7511a(f) NO_x measures would contribute to ozone attainment. The commission has performed photochemical grid modeling which predicts that NO_x emission reductions, such as those required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The §7511a(f) exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under §7511a(f) was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App. - Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. - Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *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).

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

As discussed earlier in this preamble, this rulemaking implements requirements of the FCAA. There is no contract or delegation agreement that covers the topic that is the subject of this rulemaking. In addition, the rulemaking was not developed solely under the general powers of the agency, but was specifically developed to meet the NAAQS established under federal law and authorized under the Texas Health and Safety Code, Texas Clean Air Act (TCAA), §§382.011, 382.012, 382.014, 382.016, 382.017, 382.021 and 382.051(d). Therefore, the proposed rules do not exceed a standard set by federal law, exceed an express requirement of state law, exceed a requirement of a delegation agreement, nor are adopted solely under the general powers of the agency.

The commission invites public comment on the draft RIA determination.

TAKINGS IMPACT ASSESSMENT

The commission evaluated this rulemaking action and performed an analysis of whether the proposed rules are subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. The specific purposes of these rules are to achieve reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. Texas Government Code, §2007.003(b)(4), provides that

Chapter 2007 does not apply to these proposed rules, because they are reasonably taken to fulfill an obligation mandated by federal law. The emission limitations and control requirements within this rulemaking were developed in order to meet the NAAQS for ozone 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 ozone standard will eventually require substantial NO_x reductions as well as VOC reductions. Any NO_x reductions resulting from the current rulemaking are no greater than what scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard.

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 rule revisions 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 HGA area exceeding the NAAQS for ground-level ozone, 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 HGA nonattainment area. Consequently, these rules meet the exemption in §2007.003(b)(13).

The commission included elsewhere in this preamble its reasons for proposing this strategy and explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being proposed concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking action therefore meets the requirements of Texas Government Code, §2007.003(b)(4) and (13). For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

COASTAL MANAGEMENT PROGRAM CONSISTENCY REVIEW

The commission determined that this rulemaking action 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's 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 rulemaking action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and determined that this rulemaking action is consistent with the applicable CMP goals and policies. The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(1)). No new sources of air contaminants will be authorized and ozone levels will be reduced as a result of these rules. The CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations in 40 CFR, to protect and enhance air quality in the coastal area (31 TAC §501.14(q)). This rulemaking action complies with 40 CFR. Therefore, in compliance with 31 TAC §505.22(e), this rulemaking action is consistent with CMP goals and policies. Interested persons may submit comments on the consistency of the proposed rules with the CMP during the public comment period.

ANNOUNCEMENT OF HEARINGS

The commission will hold a public hearing on this proposal on July 2, 2001 at 6:00 p.m., Houston City Hall Council Chambers, 2nd Floor, 901 Bagby, Houston. The hearing is structured for the receipt of oral or written comments by interested persons. Registration will begin one hour prior to the hearing. Individuals may present oral statements when called upon in order of registration. A four-minute time limit will be established at the hearing to assure that enough time is allowed for every interested person to speak. Open discussion will not occur during the hearing; however, agency staff members will be available to discuss the proposal one hour before the hearing, and will answer questions before and after the hearing. Earlier public hearings on this proposal were scheduled at the following times and locations: June 13, 2001, 6:00 p.m., Galveston City Council Chambers, Room 200, 823 Rosenberg, Galveston; June 14, 2001, 10:00 a.m., Rosenberg Civic and Convention Center, Room C, 3825 Highway 36 South, Rosenberg; June 14, 2001, 6:00 p.m., Houston City Hall Council Chambers, 2nd Floor, 901 Bagby, Houston; and June 15, 2001, 10:00 a.m., Texas Natural Resource Conservation Commission, Building E, Room 201S, 12100 North I-35, Austin. The notices for the June 13 - 15 hearings were published in the Fort Worth Star-Telegram, Houston Chronicle, Longview News-Journal, and the San Antonio Express-News on May 11, 2001 and in the Austin American Statesman and Beaumont Enterprise on May 12, 2001. A public hearings notice was also published in the June 8, 2001 issue of the *Texas Register*.

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

Written comments may be submitted to Ms. Heather Evans, Office of Environmental Policy, Analysis, and Assessment, MC 206, P.O. Box 13087, Austin, Texas 78711-3087, faxed to (512) 239-4808, or emailed to *siprules@tnrcc.state.tx.us*. All comments should reference Rule Log Number 2001-007b-117-AI. Comments must be received by 5:00 p.m., July 2, 2001, although written comments submitted at the July 2, 2001 hearing will be accepted. On May 10, 2001, the commission proposed changes to Chapters 114, 117, and to the SIP which were made available on the commission's web site and which were the subject of newspaper notices as listed in the ANNOUNCEMENT OF HEARINGS portion of this preamble. Subsequently, on May 30, 2001 the commission proposed changes to Chapters 101, 117 and the SIP. The latest versions of all of the proposed rules in Chapters 101, 114 and 117 and the SIP revision were placed on the commission's web site on May 30, 2001 and are available at *http://www.tnrcc.state.tx.us/oprd/sips/houston.html*. For further information or questions concerning this proposal, please contact Eddie Mack at (512) 239-1488.

STATUTORY AUTHORITY

The amendment is proposed under Texas Water Code (TWC), §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, which authorizes the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendment is also proposed under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

The proposed amendment implements TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d).

SUBCHAPTER A: DEFINITIONS

§117.10

§117.10. Definitions.

Unless specifically defined in the Texas Clean Air Act or Chapter 101 of this title (relating to General Air Quality Rules), the terms in this chapter shall have the meanings commonly used in the field of air pollution control. Additionally, the following meanings apply, unless the context clearly indicates otherwise.

(1) - (10) (No change.)

(11) **Diesel engine** - A compression-ignited two- or four-stroke engine in which liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition.

(12) [(11)] **Electric generating facility (EGF)** - A facility that generates electric energy for compensation and is owned or operated by a person doing business in this state, including a municipal corporation, electric cooperative, or river authority.

(13) [(12)] **Electric power generating system** - One electric power generating system consists of either:

(A) for the purposes of Subchapter B, Division 1 of this chapter (relating to Utility Electric Generation in Ozone Nonattainment Areas), all [All] boilers, auxiliary steam boilers, and stationary gas turbines that generate electric energy for compensation; are owned or operated by a municipality or a Public Utility Commission of Texas regulated utility, or any of its successors; and are entirely located in one of the following ozone nonattainment areas:

(i) Beaumont/Port Arthur;

(ii) Dallas/Fort Worth;

(iii) Houston/Galveston; [or]

(B) for the purposes of Subchapter B, Division 2 of this chapter (relating to Utility Electric Generation in East and Central Texas), all [All] boilers, auxiliary steam boilers, and stationary gas turbines that generate electric energy for compensation; are owned or operated by an electric cooperative, independent power producer, municipality, river authority, or public utility, or any of its successors; and are located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, or Wharton County; or [.]

(C) for the purposes of Subchapter B, Division 3 of this chapter (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas), all units in the Houston/Galveston ozone nonattainment area that generate electricity but do not meet the conditions specified in subparagraph (A) of this paragraph, including, but not limited to, cogeneration units and units owned by independent power producers.

(14) **Emergency situation** - As follows.

(A) An emergency situation is any of the following:

(i) an unforeseen electrical power failure from the serving electric power generating system;

(ii) the period of time during which an emergency notice, as defined in *ERCOT Protocols, Section 2: Definitions and Acronyms* (January 5, 2001), issued by the Electric Reliability Council of Texas, Inc. (ERCOT) as specified in *ERCOT Protocols, Section 5: Dispatch* (January 5, 2001), is applicable to the serving electric power generating system. The emergency situation is considered to end upon expiration of the emergency notice issued by ERCOT;

(iii) an unforeseen failure of on-site electrical transmission equipment (e.g., a transformer);

(iv) an unforeseen failure of natural gas service;

(v) an unforeseen flood or fire, or a life-threatening situation; or

(vi) operation of emergency generators for Federal Aviation Administration licensed or military airports for the purposes of providing power in anticipation of a power failure due to severe storm activity.

(B) An emergency situation does not include operation for purposes of supplying power for distribution to the electric grid, operation for training purposes, or other foreseeable events.

(15) [(13)] **Functionally identical replacement** - A unit that performs the same function as the existing unit which it replaces, with the condition that the unit replaced must be physically removed or rendered permanently inoperable before the unit replacing it is placed into service.

(16) [(14)] **Heat input** - The chemical heat released due to fuel combustion in a unit, using the higher heating value of the fuel. This does not include the sensible heat of the incoming combustion air. In the case of carbon monoxide (CO) boilers, the heat input includes the enthalpy of all regenerator off-gases and the heat of combustion of the incoming carbon monoxide and of the auxiliary fuel. The enthalpy change of the fluid catalytic cracking unit regenerator off-gases refers to the total

heat content of the gas at the temperature it enters the CO boiler, referring to the heat content at 60 degrees Fahrenheit, as being zero.

(17) [(15)] **Heat treat furnace** - A furnace that is used in the manufacturing, casting, or forging of metal to heat the metal so as to produce specific physical properties in that metal.

(18) [(16)] **High heat release rate** - A ratio of boiler design heat input to firebox volume (as bounded by the front firebox wall where the burner is located, the firebox side waterwall, and extending to the level just below or in front of the first row of convection pass tubes) greater than or equal to 70,000 British thermal units (Btu) per hour per cubic foot.

(19) [(17)] **Horsepower rating** - The engine manufacturer's maximum continuous load rating at the lesser of the engine or driven equipment's maximum published continuous speed.

(20) [(18)] **Incinerator** - For the purposes of this chapter, the term "incinerator" includes both of the following:

(A) an enclosed control device that combusts or oxidizes gases or vapors; and

(B) an incinerator as defined in §101.1 of this title (relating to Definitions).

(21) [(19)] **Industrial boiler** - Any combustion equipment, not including utility or auxiliary steam boilers as defined in this section, fired with liquid, solid, or gaseous fuel, that is used to produce steam.

(22) [(20)] **International Standards Organization (ISO) conditions** - ISO standard conditions of 59 degrees Fahrenheit, 1.0 atmosphere, and 60% relative humidity.

(23) [(21)] **Large DFW system** - All boilers, auxiliary steam boilers, and stationary gas turbines that are located in the Dallas/Fort Worth ozone nonattainment area, and were part of one electric power generating system on January 1, 2000, that had a combined electric generating capacity equal to or greater than 500 megawatts.

(24) [(22)] **Lean-burn engine** - A spark-ignited or compression-ignited, Otto cycle, diesel cycle, or two-stroke engine that is not capable of being operated with an exhaust stream oxygen concentration equal to or less than 0.5% by volume, as originally designed by the manufacturer.

(25) [(23)] **Low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit** - An industrial, commercial, or institutional boiler; process heater; or gas turbine supplemental waste heat recovery unit with maximum rated capacity:

(A) greater than or equal to 40 million Btu per hour (MMBtu/hr), but less than 100 MMBtu/hr and an annual heat input less than or equal to 2.8 (10^{11}) Btu per year (Btu/yr), based on a rolling 12-month average; or

(B) greater than or equal to 100 MMBtu/hr and an annual heat input less than or equal to 2.2 (10^{11}) Btu/yr, based on a rolling 12-month average.

(26) [(24)] **Low annual capacity factor stationary gas turbine or stationary internal combustion engine** - A stationary gas turbine or stationary internal combustion engine which is demonstrated to operate less than 850 hours per year, based on a rolling 12-month average.

(27) [(25)] **Low heat release rate** - A ratio of boiler design heat input to firebox volume less than 70,000 Btu per hour per cubic foot.

(28) [(26)] **Major source** - Any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit:

(A) at least 50 tons per year (tpy) of nitrogen oxides (NO_x) and is located in the Beaumont/Port Arthur ozone nonattainment area;

(B) at least 50 tpy of NO_x and is located in the Dallas/Fort Worth ozone nonattainment area;

(C) at least 25 tpy of NO_x and is located in the Houston/Galveston ozone nonattainment area; or

(D) the amount specified in the major source definition contained in the Prevention of Significant Deterioration of Air Quality regulations promulgated by EPA in Title 40 Code of Federal Regulations (CFR) §52.21 as amended June 3, 1993 (effective June 3, 1994) and is located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Comal, Ellis, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Hays, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, or Wharton County.

<u>(29)</u> [(27)] **Maximum rated capacity** - The maximum design heat input, expressed in MMBtu/hr, unless:

(A) the unit is a boiler, utility boiler, or process heater operated above the maximum design heat input (as averaged over any one-hour period), in which case the maximum operated hourly rate shall be used as the maximum rated capacity; or

(B) the unit is limited by operating restriction or permit condition to a lesser heat input, in which case the limiting condition shall be used as the maximum rated capacity; or

(C) the unit is a stationary gas turbine, in which case the manufacturer's rated heat consumption at the International Standards Organization (ISO) conditions shall be used as the maximum rated capacity, unless limited by permit condition to a lesser heat input, in which case the limiting condition shall be used as the maximum rated capacity; or

(D) the unit is a stationary, internal combustion engine, in which case the manufacturer's rated heat consumption at Diesel Equipment Manufacturer's Association or ISO conditions shall be used as the maximum rated capacity, unless limited by permit condition to a lesser heat input, in which case the limiting condition shall be used as the maximum rated capacity.

(30) [(28)] **Megawatt (MW) rating** - The continuous MW rating or mechanical equivalent by a gas turbine manufacturer at ISO conditions, without consideration to the increase in gas turbine shaft output and/or the decrease in gas turbine fuel consumption by the addition of energy recovered from exhaust heat.

(31) [(29)] **Nitric acid** - Nitric acid which is 30% to 100% in strength.

(32) [(30)] **Nitric acid production unit** - Any source producing nitric acid by either the pressure or atmospheric pressure process.

(33) [(31)] **Nitrogen oxides (NO_x)** - The sum of the nitric oxide and nitrogen dioxide in the flue gas or emission point, collectively expressed as nitrogen dioxide.

(34) [(32)] **Parts per million by volume (ppmv)** - All ppmv emission limits specified in this chapter are referenced on a dry basis.

(35) [(33)] **Peaking gas turbine or engine** - A stationary gas turbine or engine used intermittently to produce energy on a demand basis.

(36) [(34)] **Plant-wide emission limit** - The ratio of the total allowable nitrogen oxides mass emissions rate dischargeable into the atmosphere from affected units at a major source when firing at their maximum rated capacity to the total maximum rated capacities for those units.

(37) [(35)] **Plant-wide emission rate** - The ratio of the total actual nitrogen oxides mass emissions rate discharged into the atmosphere from affected units at a major source when firing at their maximum rated capacity to the total maximum rated capacities for those units.

(38) [(36)] **Predictive emissions monitoring system (PEMS)** - The total equipment necessary for the continuous determination and recordkeeping of process gas concentrations and emission rates using process or control device operating parameter measurements and a conversion equation, graph, or computer program to produce results in units of the applicable emission limitation.

(39) [(37)] **Process heater** - Any combustion equipment fired with liquid and/or gaseous fuel which is used to transfer heat from combustion gases to a process fluid, superheated steam, or water for the purpose of heating the process fluid or causing a chemical reaction. The term "process

heater" does not apply to any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment, or to boilers as defined in this section.

(40) **Pyrolysis reactor** - Any combustion equipment in which hydrocarbon products are produced from the endothermic cracking of feedstocks such as ethane, propane, butane, and naphtha.

(41) [(38)] **Reheat furnace** - A furnace that is used in the manufacturing, casting, or forging of metal to raise the temperature of that metal in the course of processing to a temperature suitable for hot working or shaping.

(42) [(39)] **Rich-burn engine** - A spark-ignited, Otto cycle, four-stroke, naturally aspirated or turbocharged engine that is capable of being operated with an exhaust stream oxygen concentration equal to or less than 0.5% by volume, as originally designed by the manufacturer.

(43) [(40)] **Small DFW system** - All boilers, auxiliary steam boilers, and stationary gas turbines that are located in the Dallas/Fort Worth ozone nonattainment area, and were part of one electric power generating system on January 1, 2000, that had a combined electric generating capacity less than 500 megawatts.

(44) [(41)] **Stationary gas turbine** - Any gas turbine system that is gas and/or liquid fuel fired with or without power augmentation. This unit is either attached to a foundation at a major

source or is portable equipment operated at a specific major source for more than 90 days in any 12-month period. Two or more gas turbines powering one shaft shall be treated as one unit.

(45) [(42)] **Stationary internal combustion engine** - A reciprocating engine that remains or will remain at a location (a single site at a building, structure, facility, or installation) for more than 12 consecutive months. Included in this definition is any engine that, by itself or in or on a piece of equipment, is portable, meaning designed to be and capable of being carried or moved from one location to another. Indicia of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine being replaced is included in calculating the consecutive residence time period. An engine is considered stationary if it is removed from one location for a period and then returned to the same location in an attempt to circumvent the consecutive residence time requirement.

(46) [(43)] **System-wide emission limit** - The ratio of the total allowable nitrogen oxides mass emissions rate dischargeable into the atmosphere from affected units in an electric power generating system or portion thereof located within a single ozone nonattainment area when firing at their maximum rated capacity to the total maximum rated capacities for those units. For fuel oil firing, average activity levels shall be used in lieu of maximum rated capacities for the purpose of calculating the system-wide emission limit.

(47) [(44)] **System-wide emission rate** - The ratio of the total actual nitrogen oxides mass emissions rate discharged into the atmosphere from affected units in an electric power generating system or portion thereof located within a single ozone nonattainment area when firing at their maximum rated capacity to the total maximum rated capacities for those units. For fuel oil firing, average activity levels shall be used in lieu of maximum rated capacities for the purpose of calculating the system-wide emission rate.

(48) [(45)] **Thirty-day rolling average** - An average, calculated for each day that fuel is combusted in a unit, of all the hourly emissions data for the preceding 30 days that fuel was combusted in the unit.

(49) [(46)] **Twenty-four hour rolling average** - An average, calculated for each hour that fuel is combusted (or acid is produced, for a nitric or adipic acid production unit), of all the hourly emissions data for the preceding 24 hours that fuel was combusted in the unit.

(50) [(47)] **Unit** - A unit consists of either:

(A) for the purposes of §117.105 and §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology) and each requirement of this chapter associated with §117.105 and §117.205 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section; or

(B) for the purposes of §117.106 and §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations) and each requirement of this chapter associated with §117.106 and §117.206 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section, or any other stationary source of nitrogen oxides (NO_x) at a major source, as defined in this section; or [.]

(C) for the purposes of §117.475 of this title (relating to Emission Specifications) and each requirement of this chapter associated with §117.475 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section.

(51) [(48)] **Utility boiler** - Any combustion equipment owned or operated by a municipality or Public Utility Commission of Texas regulated utility, fired with solid, liquid, and/or gaseous fuel, used to produce steam for the purpose of generating electricity.

(52) [(49)] **Wood** - Wood, wood residue, bark, or any derivative fuel or residue thereof in any form, including, but not limited to, sawdust, sander dust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

SUBCHAPTER B: COMBUSTION AT MAJOR SOURCES

DIVISION 1: UTILITY ELECTRIC GENERATION IN OZONE NONATTAINMENT AREAS

§§117.101, 117.103, 117.106 - 117.110, 117.119

STATUTORY AUTHORITY

The amendments are proposed under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also proposed under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures;§382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

The proposed amendments implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d).

§117.101. Applicability.

(a) The provisions of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas) shall apply to the following units used in an electric power generating system, as defined in <u>§117.10(13)(A)</u> [§117.10(12)(A)] of this title (relating to Definitions), owned or operated by a municipality or a Public Utility Commission of Texas (PUC) regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC, located within the Beaumont/Port Arthur, Houston/Galveston, or Dallas/Fort Worth ozone nonattainment areas:

(1) (No change.)

(2) auxiliary steam boilers; [and]

(3) stationary gas turbines<u>; and</u> [.]

<u>(4) duct burners used in turbine exhaust ducts.</u>

(b) (No change.)

§117.103. Exemptions.

(a) - (c) (No change.)

[(d) Distributed generation. Upon issuance of a standard permit by the commission for small (ten megawatts or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid, combustion sources registered under that permit are exempt from this chapter.]

§117.106. Emission Specifications for Attainment Demonstrations.

(a) Beaumont/Port Arthur. The owner or operator of each utility boiler located in the Beaumont/Port Arthur ozone nonattainment area shall ensure that emissions of nitrogen oxides (NO_x) do not exceed 0.10 pound per million Btu (lb/MMBtu) heat input, on a daily average, except as provided in §117.108 of this title (relating to System Cap), or §117.570 of this title (relating to <u>Use of Emissions Credits for Compliance</u> [Trading]).

(b) (No change.)

(c) Houston/Galveston. The owner or operator of each utility boiler, auxiliary steam boiler, or stationary gas turbine located in the Houston/Galveston ozone nonattainment area shall ensure that emissions of NO_x do not exceed the lower of any applicable permit limit <u>in a permit issued or</u>

application deemed administratively complete before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the following rates, in lb/MMBtu heat input, on the basis of daily and 30-day averaging periods as specified in §117.108 of this title, and as specified in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program):

(1) utility boilers:

(A) gas-fired, 0.020 [0.010]; and

(B) coal-fired or oil-fired, 0.040; [:]

[(i) wall-fired, 0.030; and]

[(ii) tangential-fired, 0.030;]

(2) (No change.)

(3) stationary gas turbines (including duct burners used in turbine exhaust ducts):

(A) - (B) (No change.)

(4) (No change.)

(5) if and to the extent supported by the commission's continuing scientific assessment of the causes of and possible solutions to the Houston/Galveston area's nonattainment status for ozone, the executive director determines that attainment can be reached with fewer NO_x emission reductions from point sources concurrent with additional emission reduction strategies, then the executive director will develop proposed rulemaking and a proposed state implementation plan revision involving revisions to the emission specifications in paragraphs (1) - (4) of this section for consideration at a commission agenda no later than June 1, 2002. In the event that the total NO_x emission reductions from utility and non-utility point sources required for attainment is determined to be 80% from the 1997 emissions inventory baseline, the revised specifications shall be the lower of any applicable permit limit in a permit issued or application deemed administratively complete before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the specifications in the following subparagraphs. The TNRCC reserves all rights to assign any additional NO_x reduction benefits supported by the science evaluation to the relief of other control measures, including further NO_x point source relief.

(A) utility boilers:

(i) gas-fired, 0.030;

(ii) coal-fired or oil-fired;

(I) wall-fired, 0.050; and

(II) tangential-fired, 0.045;

(B) auxiliary steam boilers, 0.030; and

(C) stationary gas turbines (including duct burners used in turbine exhaust ducts), 0.032.

(d) Related emissions. No person shall allow the discharge into the atmosphere from any unit [boiler] subject to the NO_x emission limits specified in subsections (a), (b), and (c) of this section:

(1) - (2) (No change.)

(e) Compliance flexibility.

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

(A) (No change.)

(B) §117.570 of this title [(relating to Trading)].

(2) - (3) (No change.)

(4) In the Houston/Galveston ozone nonattainment area, [an owner or operator may not use the alternative methods specified in §117.570 of this title to comply with the NO_x emission specifications of this section. In addition,] the following requirements apply.

(A) For units which meet the definition of electric generating facility (EGF), the owner or operator must use both the [alternative] methods specified in §117.108 of this title and the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) to comply with the NO_x emission specifications of this section. An owner or operator may use the alternative methods specified in §117.570 of this title for purposes of complying with §117.108 of this title.

(B) (No change.)

§117.107. Alternative System-wide Emission Specifications.

(a) An owner or operator of any gaseous- or coal-fired utility boiler or stationary gas turbine may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) by achieving compliance with a system-wide emission limitation. Any owner or operator who elects to comply with system-wide emission limits shall reduce emissions of NO_x from affected units so that, if all such units were operated at their maximum rated capacity, the system-wide emission rate from all units in the system as defined in <u>§117.10(13)(A)</u> [§117.10(11)(A)] of this title <u>(relating to Definitions)</u> would not exceed the system-wide emission limit as defined in §117.10 of this title [(relating to Definitions)].

(1) - (3) (No change.)

(b) - (d) (No change.)

§117.108. System Cap.

(a) (No change.)

(b) Each EGF within an electric power generating system, as defined in <u>§117.10(13)(A)</u> [§117.10(12)(A)] of this title (relating to Definitions), that would otherwise be subject to the NO_x emission rates of §117.106 of this title must be included in the system cap.

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

(1) A rolling 30-day average emission cap shall be calculated using the following equation.

Figure: 30 TAC §117.108(c)(1)

$$\begin{array}{c}NO_x \text{ 30-day rolling} \\ \text{average emission cap} \\ \text{(lb/day)}\end{array} = \sum_{i=1}^{N} (H_i \times R_i)$$

Where:

i = each EGF in the electric power generating system

N = the total number of EGFs in the emission cap

H_i = (A) For the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, the average of the daily heat input for each EGF in the emission cap, in million Btu per day, as certified to the executive director, for the system highest 30-day period in the nine months of July, August, and September 1996, 1997, and 1998. For EGFs exempt from the 40 Code of Federal Regulations (CFR) Part 75 monitoring requirements, if the heat input data corresponding to the system highest 30-day period (as determined for EGFs in the system subject to 40 CFR Part 75 monitoring) is not available, the daily average of the highest calendar month heat input in 1996-1998 may be used.

(B) For the Houston/Galveston ozone nonattainment area:

(i) The average of the daily heat input for each EGF in the emission cap, in million Btu per day, as certified to the executive director, for any [the] system [highest] 30-day period in the nine months of July, August, and September 1997, 1998, and 1999;

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

(iii) The level of activity authorized by the executive director for the third quarter (July, August, and September), until such time two consecutive third quarters of actual level of activity data are available, shall be used for the following:

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

(II) EGFs which qualify for a permit by rule under Chapter 106 of this title and have commenced construction before January 2, 2001; and

(III) EGFs which were not in operation before [prior to] January 1, 1997.

R_i = (A) For EGFs in the Beaumont/Port Arthur ozone nonattainment area, the emission limit of §117.106(a) of this title;

(B) For EGFs in the Dallas/Fort Worth ozone nonattainment area, the emission limit of §117.106(b) of this title; and

(C) For EGFs in the Houston/Galveston ozone nonattainment area, the emission limit of §117.106(c) of this title.

(2) - (3) (No change.)

(d) - (k) (No change.)

§117.109. System Cap Flexibility.

An owner or operator of a source of nitrogen oxides (NO_x) [in the Dallas/Fort Worth ozone nonattainment area] who is participating in the system cap under §117.108 of this title (relating to System Cap) may exceed their system cap provided that the owner or operator is complying with the requirements of §117.570 of this title (relating to Use of Emissions Credits for Compliance) or Chapter 101, Subchapter H, Division 1, 4, or 5 of this title (relating to Emission Credit Banking and Trading; Discrete Emission Credit and Trading Program; and System Cap Trading).

§117.110. Change of Ownership - System Cap.

In the event that a unit within an electric power generating system is sold or transferred, the unit shall become subject to the transferee's system cap. <u>In the Dallas/Fort Worth ozone nonattainment area, the</u> [The] value $\underline{R_i}$ [Ri] in §117.108(c) of this title (relating to System Cap) is based on the unit's status as part of a large or small system as of January 1, 2000, and does not change as a result of sale or transfer of the unit, regardless of the size of the transferee's system.

§117.119. Notification, Recordkeeping, and Reporting Requirements.

(a) (No change.)

(b) Notification. The owner or operator of a unit subject to the emission specifications of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas) shall submit notification to the appropriate regional office and any local air pollution control agency having jurisdiction [executive director] as follows:

(1) - (2) (No change.)

(c) Reporting of test results. The owner or operator of an affected unit shall furnish the Office of Compliance and Enforcement, the appropriate regional office, [executive director] and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.111 of this title or any CEMS or PEMS performance evaluation conducted under §117.113 of this title:

(1) - (2) (No change.)

(d) - (e) (No change.)

DIVISION 2: UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS

§117.138

STATUTORY AUTHORITY

The amendment is proposed under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendment is also proposed under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

The proposed amendment implements TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d).

§117.138. System Cap.

(a) (No change.)

(b) Each unit within an electric power generating system, as defined in §117.10(13)(B) [§117.10(12)(B)] of this title (relating to Definitions), that would otherwise be subject to the NO_x emission limits of §117.135 of this title must be included in the system cap.

(c) - (k) (No change.)

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

§§117.203, 117.206, 117.210, 117.213, 117.214, 117.219

STATUTORY AUTHORITY

The amendments are proposed under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also proposed under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state’s air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

The proposed amendments implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d).

§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) [§117.209(c)(1)] 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) - (5) (No change.)

(6) stationary gas turbines and engines, which are used as follows:

(A) [used] in research and testing; [, or used]

(B) for purposes of performance verification and testing; [, or used]

(C) solely to power other engines or gas turbines during start-ups; [, or operated]

(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 40 Code of Federal Regulations (CFR) §60.14 (effective July 21, 1992), and §60.15 (effective December 16, 1975), respectively; [for firefighting and/or flood control, or used]

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

(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 [used]

(G) as chemical processing gas turbines; [or]

[(B) demonstrated to operate less than 850 hours per year, based on a rolling 12-month average;]

(7) - (8) (No change.)

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

(10) any stationary diesel engine in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment area; [diesel-fired stationary internal combustion engines.]

(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 40 CFR §60.14 (effective July 21, 1992), and §60.15 (effective December 16, 1975), respectively; 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; and

(B) meets the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 (effective 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 40 CFR §60.14 (effective July 21, 1992), and §60.15 (effective December 16, 1975), respectively.

(b) The exemptions in paragraphs (1), (2), [(6)(B),] (7), and (8)(A) of subsection (a) 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) Upon issuance of a standard permit by the commission for small (ten MW or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid, combustion sources registered under that permit are exempt from this chapter.]

§117.206. Emission Specifications for Attainment Demonstrations.

(a) - (b) (No change.)

(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 or application deemed administratively complete before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the following:

(1) (No change.)

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

(A) (No change.)

(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) (No change.)

(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) (No change.)

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

(i) (No change.)

(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) - (8) (No change.)

(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, 0.17 g NO_x/hp-hr;

(B) gas-fired lean-burn engines, [0.50 g NO_x/hp-hr,] 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; [and]

(C) dual-fuel engines:

(i) (No change.)

(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, 11.0 g NO_x/hp-hr. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in 40 CFR §60.14 (effective July 21, 1992), and §60.15 (effective December 16, 1975), respectively; 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) - (15) (No change.)

(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; and [.]

(18) if and to the extent supported by the commission's continuing scientific assessment of the causes of and possible solutions to the Houston/Galveston area's nonattainment status for ozone, the executive director determines that attainment can be reached with fewer NO_x emission reductions from point sources concurrent with additional emission reduction strategies, then the executive director will develop proposed rulemaking and a proposed state implementation plan revision involving revisions to the emission specifications in paragraphs (1) - (17) of this section for consideration at a commission agenda no later than June 1, 2002. In the event that the total NO_x emission reductions from utility and non-utility point sources required for attainment is determined to be 80% from the 1997 emissions inventory baseline, the revised specifications shall be the lower of any applicable permit limit in a permit issued or application deemed administratively complete before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the specifications in the following subparagraphs. The TNRCC reserves all rights to assign any additional NO_x reduction benefits supported by the science evaluation to the relief of other control measures, including further NO_x point source relief.

(A) gas-fired boilers:

(i) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.020 lb NO_x per MMBtu;

(ii) 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

(iii) 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% O2 , dry basis);

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

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

(ii) 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

(iii) alternatively, for units which did not use a CEMS or 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 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;

(C) 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):

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

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

(I) 0.030 lb NO_x per MMBtu; or

(II) a 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;

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

(E) wood fuel-fired boilers, 0.046 lb NO_x per MMBtu;

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

(G) liquid-fired boilers, 2.0 lb NO_x per 1,000 gallons of liquid burned;

(H) process heaters, except for pyrolysis reactors:

(i) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.025 lb NO_x per MMBtu;

(ii) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.025 lb NO_x per MMBtu; and

(iii) with a maximum rated capacity less than 40 MMBtu/hr, 0.036 lb NO_x per MMBtu;

(I) pyrolysis reactors:

(i) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.036 lb NO_x per MMBtu;

(ii) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.036 lb NO_x per MMBtu;

(J) stationary, reciprocating internal combustion engines:

(i) 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;

(ii) gas-fired lean-burn engines, except as specified in clause (iii) of this subparagraph:

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

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

(iii) 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

(iv) diesel engines, excluding dual-fuel engines, as specified in paragraph (9)(D) of this subsection;

(K) stationary gas turbines:

(i) rated at 10 MW or greater, 0.032 lb NO_x per MMBtu; and

(ii) rated at 1.0 MW or greater, but less than 10 MW, 0.15 lb NO_x per MMBtu; and

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

(L) duct burners used in turbine exhaust ducts, the corresponding gas turbine emission limitation of subparagraph (K) of this paragraph;

(M) pulping liquor recovery furnaces, either:

(i) 0.050 lb NO_x per MMBtu; or

(ii) 1.08 lb NO_x per ADTP;

(N) kilns:

(i) lime kilns, 0.66 lb NO_x per ton of CaO; and

(ii) lightweight aggregate kilns, 0.76 lb NO_x per ton of product;

(O) metallurgical furnaces:

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

(ii) reheat furnaces, 0.062 lb NO_x per MMBtu;

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

(Q) incinerators, either of the following:

(i) 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

(ii) 0.030 lb NO_x per MMBtu; and

(R) as an alternative to the emission specifications in subparagraphs (A) - (P) of this paragraph for units with an annual capacity factor of 0.0383 or less, 0.060 lb NO_x per MMBtu.

(d) - (e) (No change.)

(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) - (B) (No change.)

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

(2) - (3) (No change.)

(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) (No change.)

(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 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;

(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. If a unit would qualify for an exemption from the emission specifications of this section except for also being classified as a unit for which this section includes an emission specification, then the unit shall be subject to that emission specification, regardless of any changes

made to the unit after December 31, 2000. For example, a sulfuric acid regeneration unit (which would otherwise qualify for exemption under §117.203(a)(4) of this title (relating to Exemptions)) that is also authorized to operate as a BIF unit as of December 31, 2000 shall be subject to the emission specification for BIF units, regardless of any changes made to the unit after December 31, 2000; and

(3) the owner or operator of units which combust fuel or waste [utilize liquid or gaseous] streams containing chemical-bound nitrogen [as a source of fuel or combustion air] shall not direct these streams to flares or other units which are not subject to an emission specification in subsection (c) of this section, unless:

(A) [(1)] the unit which receives the chemical-bound nitrogen stream is opted into the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title; and

(B) [(2)] NO_x emissions from this opt-in unit are 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).

(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.

§117.210. System Cap.

(a) The owner or operator of each electric generating facility (EGF) in the Houston/Galveston ozone nonattainment area must comply with a daily and 30-day system cap emission limitation for nitrogen oxides (NO_x) in accordance with the requirements of this section. Each EGF in the system cap shall be subject to the daily cap and appropriate 30-day cap of this section at all times. EGFs are not subject to this section if electric output is entirely dedicated to industrial customers. "Entirely dedicated" may include up to two weeks per year of service to the electric grid when the industrial customers' load sources are not operating.

(b) (No change.)

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

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

Figure: 30 TAC §117.210(c)(1)

$$\begin{matrix}\text{NO}_x\text{ 30-day rolling} \\ \text{average emission cap} \\ \text{(lb/day)}\end{matrix} = \sum_{i=1}^{N} (H_i \times R_i)$$

Where:

i = each EGF in the electric power generating system

N = the total number of EGFs in the emission cap

H_i = (A) The average of the daily heat input for each EGF in the emission cap, in million Btu per day, as certified to the executive director, for the system highest 30-day period in the nine months of July, August, and September 1997, 1998, and 1999;

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

(C) The level of activity authorized by the executive director for the third quarter (July, August, and September), until such time two consecutive third quarters of actual level of activity data are available, shall be used for the following:

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

(ii) EGFs which qualify for a permit by rule under Chapter 106 of this title and have commenced construction before January 2, 2001; and

(iii) EGFs which were not in operation before [prior to] January 1, 1997.

R_i = the emission limit of §117.206(c) of this title.

[(A) gas-fired boilers, 0.010 pound NO_x per million British thermal units (lb NO_x per MMBtu) heat input;]

[(B) coal-fired or oil-fired boilers:]

[(i) wall-fired, 0.030 lb NO_x per MMBtu heat input; and]

[(ii) tangential-fired, 0.030 lb NO_x per MMBtu heat input;]

[(C) coke-fired boilers, 0.057 lb NO_x per MMBtu heat input;]

[(D) stationary gas turbines:]

[(i) rated at 1.0 megawatt (MW) or greater, 0.015 lb NO_x per MMBtu heat input; and]

[(ii) rated at less than 1.0 MW:]

[(I) with initial start of operation on or before December 31, 2000, 0.15 lb NO_x per MMBtu heat input; and]

[(II) with initial start of operation after December 31, 2000, 0.015 lb NO_x per MMBtu heat input;]

[(E) duct burners used in turbine exhaust ducts, 0.015 lb NO_x per MMBtu heat input;]

[(F) stationary, reciprocating, dual-fuel internal combustion 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]

[(H) stationary diesel engines, excluding dual-fuel engines, as specified in §117.206(c)(9)(D) of this title; and]

[(G)] as an alternative to the emission specifications in subparagraphs (A) - (F) of this paragraph for units with an annual capacity factor of 0.0383 or less, 0.060 lb NO_x per MMBtu heat input.]

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

Figure: 30 TAC §117.210(c)(2)

$$\text{NO}_x \text{ 30-day rolling average emission cap (lb/day)} = \sum_{i=1}^{N} (H_i \times R_i)$$

Where:

i = each EGF in the electric power generating system

N = the total number of EGFs in the emission cap

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

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

(C) The level of activity authorized by the executive director for the third quarter (July, August, and September), until such time two consecutive third quarters of actual level of activity data are available, shall be used for the following:

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

(ii) EGFs which qualify for a permit by rule under Chapter 106 of this title and have commenced construction before January 2, 2001; and

(iii) EGFs which were not in operation before January 1, 1997.

R_i = the emission limit of §117.206(c) of this title.

(3) [(2)] A maximum daily cap shall be calculated using the following equation.

Figure: 30 TAC §117.210(c)(3)

[Figure: 30 TAC §117.210(c)(2)]

$$\underset{\text{(lb/day)}}{NO_x \text{ maximum daily cap}} = \sum_{i=1}^{N} \left(H_{Mi} \times R_i\right)$$

Where:

i, N, and R_i are defined as in paragraph (1) of this subsection.

H_{mi} = The maximum heat input, as certified to the executive director, allowed or possible (whichever is lower) in a day.

[(3) Each EGF in the system cap shall be subject to the emission limits of both paragraphs (1) and (2) of this subsection at all times.]

(d) - (k) (No change.)

§117.213. Continuous Demonstration of Compliance.

(a) - (b) (No change.)

(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) - (F) (No change.)

(G) lime kilns and lightweight aggregate kilns in HGA; [and]

(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).

(2) (No change.)

(d) - (h) (No change.)

(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 §117.203(a)(11) or (12) [850 hours per year exemption of §117.203(a)(6)(B)] 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) - (m) (No change.)

§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) [(1)] 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) [(2)] The carbon monoxide (CO) monitoring requirements of §117.213(d) of this title apply.

(C) [(3)] The totalizing fuel flow meter requirements of §117.213(a) of this title apply.

(D) [(4)] 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)(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) - (c) (No change.)

§117.219. Notification, Recordkeeping, and Reporting Requirements.

(a) (No change.)

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

(1) - (2) (No change.)

(c) Reporting of test results. The owner or operator of an affected unit shall furnish the Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.211 of this title and any CEMS or PEMS RATA conducted under §117.213 of this title:

(1) - (2) (No change.)

(d) - (e) (No change.)

(f) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain written or electronic records of the data specified in this subsection. Such records 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, EPA, or local air pollution control agencies having jurisdiction. The records shall include:

(1) - (5) (No change.)

(6) for units claimed exempt from emission specifications using the [low annual capacity factor] exemption of §117.205(h)(2) <u>or §117.203(a)(11) or (12) of this title (relating to Exemptions)</u>, either records of monthly:

(A) - (B) (No change.)

(7) (No change.)

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

(9) records of the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.211 of this title; and [.]

(10) for each stationary diesel or dual-fuel engine in the Houston/Galveston ozone nonattainment area, records of each time the engine is operated for testing and maintenance, including:

(A) date(s) of operation;

(B) start and end times of operation;

(C) identification of the engine; and

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

SUBCHAPTER D: SMALL COMBUSTION SOURCES

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

§§117.471, 117.473, 117.475, 117.478, 117.479

STATUTORY AUTHORITY

The amendments are proposed under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also proposed under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

The proposed amendments implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d).

§117.471. Applicability.

This division (relating to Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources) applies in the Houston/Galveston ozone nonattainment area to the following equipment at any stationary source of nitrogen oxides (NO_x) which is not a major source of NO_x:

(1) boilers and process heaters; [and]

(2) stationary, reciprocating internal combustion engines; and [.]

(3) stationary gas turbines, including duct burners.

§117.473. Exemptions.

(a) This division (relating to Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources) does not apply to the following, except as may be specified in §117.478(c) and §117.479(h) - (j) of this title (relating to Operating Requirements; and Monitoring, Recordkeeping, and Reporting Requirements):

(1) boilers and process heaters with a maximum rated capacity of 2.0 million British thermal units per hour (MMBtu/hr) or less; [and]

(2) the following stationary engines:

(A) engines with a horsepower (hp) rating of less than 50 hp [or less];

(B) - (D) (No change.)

(E) engines operated exclusively in emergency situations, except that operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after October 1, 2001 is ineligible for this exemption. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in 40 Code of Federal Regulations (CFR) §60.14 (effective July 21, 1992), and §60.15 (effective December 16, 1975), respectively [for firefighting and/or flood control];

(F) - (G) (No change.)

(H) diesel engines placed into service before October 1, 2001 which:

(i) operate less [emergency generators that do not operate more] than 100 hours per [calendar] year, based on a rolling 12-month average [provided that records are maintained as specified in §117.479(h) of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements)]; and

(ii) have not been modified, reconstructed, or relocated on or after October 1, 2001. For the purposes of this clause, the terms "modification" and "reconstruction" have the meanings defined in 40 CFR §60.14 (effective July 21, 1992), and §60.15 (effective December 16, 1975), respectively; and

(I) new, modified, reconstructed, or relocated stationary diesel [diesel-fired] engines placed into service on or after October 1, 2001 which:

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

(ii) meet the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 (effective October 23, 1998) and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in 40 CFR §60.14 (effective July 21, 1992), and §60.15 (effective December 16, 1975), respectively; and [.]

(3) stationary gas turbines rated at less than 1.0 megawatt with initial start of operation on or before October 1, 2001.

(b) (No change.)

[(c) Upon issuance of a standard permit by the commission for small (ten megawatts or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid, combustion sources registered under that permit are exempt from this chapter.]

§117.475. Emission Specifications.

(a) For sources which are subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the nitrogen oxides (NO_x) emission rate values used to determine allocations for Chapter 101, Subchapter H, Division 3 of this title shall be the lower of any applicable permit limit <u>in a permit issued before January 2, 2001</u> or the limits in subsection (c) of this section. The averaging time shall be as specified in Chapter 101, Subchapter H, Division 3 of this title.

(b) For sources which are not subject to Chapter 101, Subchapter H, Division 3 of this title, NO_x emissions are limited to the lower of any applicable permit limit <u>in a permit issued before January 2, 2001</u> or the limits in subsection (c) of this section. The averaging time shall be as follows:

(1) if the <u>unit</u> [boiler, process heater, or engine] is operated with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.479(c) of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements), either as:

(A) - (C) (No change.)

(2) (No change.)

(c) No person shall allow the discharge of NO_x emissions into the atmosphere in excess of the following rates:

(1) (No change.)

(2) from stationary, gas-fired, reciprocating internal combustion engines:

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

(B) all others, 0.50 g/hp-hr [gram per horsepower-hour (g/hp-hr)]; [and]

(3) from stationary, dual-fuel, reciprocating internal combustion engines, 5.83 g/hp-hr;

(4) from stationary, diesel, reciprocating internal combustion engines:

(A) placed into service before October 1, 2001 which have not been modified, reconstructed, or relocated on or after October 1, 2001, 11.0 g/hp-hr. For the purposes of this paragraph, the terms "modification" and "reconstruction" have the meanings defined in 40 CFR §60.14 (effective July 21, 1992), and §60.15 (effective December 16, 1975), respectively; and

(B) 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:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(5) from stationary gas turbines (including duct burners), 0.15 lb/MMBtu; and

(6) [(3)] as an alternative to the emission specifications in paragraphs (1) - (5) [and (2)] of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu heat input.

§117.478. Operating Requirements.

(a) The owner or operator shall operate any unit [boiler, process heater, or engine] subject to the emission limitations of §117.475 of this title (relating to Emission Specifications) in compliance with those limitations.

(b) All units [boilers, process heaters, and engines] subject to the emission limitations of §117.475 of this title shall be operated so as to minimize nitrogen oxides (NO_x) emissions, consistent with the emission control techniques selected, over the unit's operating or load range during normal operations. Such operational requirements include the following.

(1) - (2) (No change.)

(3) Each unit [boiler, process heater, or engine] controlled with post combustion control techniques shall be operated such that the reducing agent injection rate is maintained to limit NO_x concentrations to less than or equal to the NO_x concentrations achieved at maximum rated capacity.

(4) - (5) (No change.)

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

§117.479. Monitoring, Recordkeeping, and Reporting Requirements.

(a) Totalizing fuel flow meters.

(1) The owner or operator of each unit [boiler, process heater, or engine] subject to the emission limitations of §117.475 of this title (relating to Emission Specifications) shall install, calibrate, maintain, and operate totalizing fuel flow meters 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.

(2) (No change.)

(b) - (c) (No change.)

(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 [boiler, process heater, or engine] subject to the emission limitations of §117.475 of this title shall comply with the following testing requirements.

(1) Each unit [boiler, process heater, or engine] shall be tested for NO_x, carbon monoxide (CO), and O_2 emissions.

(2) Units [Boilers, process heaters, and engines] which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions.

(3) - (4) (No change.)

(5) For units [boilers, process heaters, or engines] 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 [boilers, process heaters, or engines] operating with CEMS or PEMS shall be demonstrated after monitor certification testing using the NO_x CEMS or PEMS.

(7) - (8) (No change.)

(f) - (g) (No change.)

(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 exempted based on run time under §117.473(a)(2)(H) or (I) of this title (relating to Exemptions) or §117.478(b)(5) of this title. The records shall be maintained for at least two 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)(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

§§117.510, 117.520, 117.534, 117.570

STATUTORY AUTHORITY

The amendments are proposed under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also proposed under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.051(d), concerning Permitting Authority of Commission; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382; and FCAA, 42 USC, §7401.

The proposed amendments implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d).

§117.510. Compliance Schedule for [For] Utility Electric Generation in Ozone Nonattainment Areas.

(a) The owner or operator of each electric utility in the Beaumont/Port Arthur ozone nonattainment area shall comply with the requirements of Subchapter B, Division 1 of this chapter (relating to Utility Electric Generation in Ozone Nonattainment Areas) as soon as practicable, but no later than the dates specified in this subsection.

(1) (No change.)

(2) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.106(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 §117.106(a) of this title have been accomplished, as measured either by:

(i) (No change.)

(ii) the total amount of emissions reductions required to comply with §117.106(a) of this title using the alternative methods to comply, either:

(I) §117.108 [Section 117.108] of this title (relating to System Cap); or

(II) §117.570 [Section 117.570] of this title (relating to Use of Emissions Credits for Compliance [Trading]);

(B) - (F) (No change.)

(b) The owner or operator of each electric utility in the Dallas/Fort Worth ozone nonattainment area shall comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than the dates specified in this subsection.

(1) (No change.)

(2) Emission specifications for attainment demonstration.

(A) The owner or operator shall comply with the requirements of §117.106(b) of this title as soon as practicable, but no later than:

(i) May 1, 2003, demonstrate that at least two-thirds of the NO_x emission reductions required by §117.106(b) of this title have been accomplished, as measured either by:

(I) (No change.)

(II) the total amount of emissions reductions required to comply with §117.106(b) of this title using the alternative methods to comply, either:

(-a-) <u>§117.108</u> [Section 117.108] of this title [(relating to System Cap)]; or

(-b-) <u>§117.570 of this title</u> [Section 117.570 (relating to Trading)];

(ii) - (vi) (No change.)

(B) (No change.)

(c) The owner or operator of each electric utility in the Houston/Galveston ozone nonattainment area shall comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than the dates specified in this subsection.

(1) (No change.)

(2) Emission specifications for attainment demonstration.

(A) The owner or operator shall comply with the requirements of §117.114 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) of this title as soon as practicable, but no later than:

(i) the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date), install any totalizing fuel flow meters [,] and emissions monitors required by §117.114 of this title. If emission controls on a unit will consist of both flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) and combustion controls, then for the purpose of determining when emissions monitors must be installed, "time of installation" means the time of installation of flue gas cleanup; and

(ii) 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(I) (No change.)

(II) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.113 of this title. [;]

(B) The owner or operator shall:

(i) no later than June 30, 2001, submit to the executive director the certification of level of activity, H_i, specified in §117.108 of this title for electric generating facilities (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, submit to the executive director the certification of activity level, H_i, specified in §117.108 of this title for EGFs which were not in operation prior to January 1, 1997; and

(iii) comply with the requirements of §117.108 of this title as soon as practicable, but no later than:

(I) [(i)] March 31, 2003, demonstrate that at least 47% [46%] of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.108 of this title; and

(II) [(ii)] March 31, 2004, demonstrate that at least 95% [92%] of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.108 of this title; and

(III) [(iii)] March 31, 2007, demonstrate compliance with the system cap limit of §117.108 of this title. [; and]

(C) For any unit subject to §117.106(c) of this title for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph (2)(A)(ii) 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 [pursuant to] §117.111 of this title; or, as applicable,

(ii) (No change.)

(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) If alternate emission specifications are implemented under §117.106(c)(5) of this title, the owner or operator of each EGF shall comply with the requirements of §117.108 of this title as soon as practicable, but no later than:

(i) March 31, 2003, demonstrate that at least 50% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.108 of this title; and

(ii) March 31, 2004, demonstrate compliance with the system cap limit of §117.108 of this title

§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) - (2) (No change.)

(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) (No change.)

(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) - (II) (No change.)

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

(B) - (F) (No change.)

(b) (No change.)

(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) (No change.)

(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) the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date), install any totalizing fuel flow meters, run time meters, and emissions monitors required by §117.214 [§117.114] of this title. If emission controls on a unit will consist of both flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) and combustion controls, then for the purpose of determining when emissions monitors must be installed, "time of installation" means the time of installation of flue gas cleanup; and

(ii) 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(I) (No change.)

(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. [;]

(B) The owner or [of] operator of each electric generating facility (EGF) shall:

(i) - (ii) (No change.)

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

(I) March 31, 2004, demonstrate that at least 39% [44%] of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.210 of this title;

(II) March 31, 2005, demonstrate that at least 67% [89%] of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.210 of this title; [and]

(III) March 31, 2006, demonstrate that at least 78% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.210 of this title; and

(IV) [(III)] March 31, 2007, demonstrate compliance with the system cap of §117.210 of this title. [;]

(C) If alternative emission specifications are implemented under §117.206(c)(18) of this title, the owner or operator of each EGF shall:

(i) perform stack tests conducted pursuant to §117.211 of this title; or, as applicable,

(ii) conduct 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

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

(I) March 31, 2004, demonstrate that at least 47% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.210 of this title;

(II) March 31, 2005, demonstrate that at least 80% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.210 of this title;

(III) March 31, 2006, demonstrate that at least 93% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.210 of this title; and

(IV) March 31, 2007, demonstrate compliance with the system cap of §117.210 of this title.

(D) [(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 pursuant to §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. [; and]

(E) [(D)] The [For non-EGFs, 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.

(F) 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.

§117.534. Compliance Schedule for Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources.

The owner or operator of each stationary source of nitrogen oxides (NO_x) in the Houston/Galveston ozone nonattainment area which is not a major source of NO_x shall comply with the requirements of Subchapter D, Division 2 of this chapter (relating to Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources) as follows.

(1) For sources which are subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the owner or operator shall:

(A) install any totalizing fuel flow meters and run time meters required by §117.479 of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements) and begin keeping records of fuel usage at the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date). If emission controls on a unit will consist of both flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) and combustion controls, then for the purpose of determining when emissions monitors must be installed, "time of installation" means the time of installation of flue gas cleanup;

(B) (No change.)

(C) no later than March 31, 2005, for any units subject to §117.475 of this title (relating to Emission Specifications) for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph (1)(B) of this section, submit to the executive director the results of:

(i) (No change.)

(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; [and]

(D) comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title as soon as practicable, but no later than the appropriate dates specified in that program; and [.]

(E) for diesel and dual-fuel engines, comply with the restriction on hours of operation for maintenance or testing, and associated recordkeeping, as soon as practicable, but no later than April 1, 2002.

(2) For sources which are not subject to Chapter 101, Subchapter H, Division 3 of this title, the owner or operator shall:

(A) install any totalizing fuel flow meters and run time meters required by §117.479 of this title and begin keeping records of fuel usage at the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date). If emission controls on a unit will consist of both flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) and combustion controls, then for the purpose of determining when emissions monitors must be installed, "time of installation" means the time of installation of flue gas cleanup;

(B) no later than 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(i) (No change.)

(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; [and]

(C) comply with all other requirements of Subchapter D, Division 2 of this chapter as soon as practicable, but no later than March 31, 2005; and [.]

(D) for diesel and dual-fuel engines, comply with the restriction on hours of operation for maintenance or testing, and associated recordkeeping, as soon as practicable, but no later than April 1, 2002.

§117.570. Use of Emissions Credits for Compliance.

(a) An owner or operator of a unit not subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions [Emission] Cap and Trade Program) may meet emission control requirements of §117.105 or §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), §117.106 or §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations), §117.107 of this title (relating to Alternative System-wide [System-Wide] Emission Specifications), or §117.207 of this title (relating to Alternative Plant-wide [Plant-Wide] Emission Specifications), [§117.108 of this title (relating to System Cap),] §117.223 of this title (relating to Source Cap), or §117.475 of this title (relating to Emission Specifications) in whole or in part, by obtaining an emission reduction credit (ERC), mobile emission reduction credit (MERC), discrete emission reduction credit (DERC), or mobile discrete emission reduction credit (MDERC) in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title (relating to Emission Credit Banking and Trading; and Discrete Emission Credit Banking and Trading) [or Chapter 101, Subchapter H, Division 4 of this title (relating to Discrete Emission Reduction Banking and

Trading)], unless there are federal or state regulations or permits under the same commission account number which contain a condition or conditions precluding such use. [For the purposes of this section, the term "reduction credit (RC)" refers to an ERC, MERC, DERC, or MDERC, whichever is applicable.]

(b) An owner or operator of a unit subject to §§117.108, 117.138, or 117.210 of this title (relating to System Cap) may meet the emission control requirements of these sections in whole or in part, by complying with the requirements of Chapter 101, Subchapter H, Division 5 of this title (relating to System Cap Trading) or by obtaining an ERC, MERC, DERC, or MDERC in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title, unless there are federal or state regulations or permits under the same commission account number which contain a condition or conditions precluding such use.

(c) For the purposes of this section, the term "reduction credit (RC)" refers to an ERC, MERC, DERC, or MDERC, whichever is applicable.

(d) [(b)] Any lower NO_x emission specification established under this chapter for the unit or units using RCs shall require the user of the RCs to obtain additional RCs in accordance with Chapter 101, Subchapter H, Division 1 [of this title] or [Chapter 101, Subchapter H, Division] 4 of this title and/or otherwise reduce emissions prior to the effective date of such rule change. For units using RCs in accordance with this section which are subject to new, more stringent rule limitations, the owner or operator using the RCs shall submit a revised final control plan to the executive director in accordance with §117.117 or §117.217 of this title (relating to Revision of Final Control Plan) to revise the basis for compliance with the emission specifications of this chapter. The owner or operator using the RCs shall submit the revised final control plan as soon as practicable, but no later than 90 days prior to the effective date of the new, more stringent rule. The owner or operator of the unit(s) currently using RCs shall calculate the necessary emission reductions per unit as follows.

Figure: 30 TAC §117.570(d)

[Figure: 30 TAC §117.570(b)]

$$\Delta E = \left[LA \times \left(ER_{old} - ER_{new} \right) \times \frac{d}{2000} \right]$$

Where:

ΔE	=	the differential of emissions
LA	=	the maximum level of activity
ER_{old}	=	the existing NO_x emission rate for the affected in lb per unit of activity
ER_{new}	=	the new NO_x emission rate for the affected unit in lb per unit of activity
d	=	(i) to calculate annual emission reductions, $d = 365$
		(ii) to calculate emission reductions for the remainder of a control period, $d =$ the number of days remaining in the control period