The Texas Natural Resource Conservation Commission (TNRCC or commission) adopts 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).

Sections 117.10, 117.106 - 117.108, 117.119, 117.203, 117.206, 117.210, 117.213, 117.214, 117.219, 117.473, 117.475, 117.478, 117.479, 117.510, 117.520, 117.534, and 117.570 are adopted *with changes* to the proposed text as published in the June 15, 2001, issue of the *Texas Register* (26 TexReg 4400). Sections 117.101, 117.103, 117.109, 117.110, 117.138, and 117.471 are adopted *without changes* and will not be republished.

The amendments to Chapter 117, concerning Control of Air Pollution from Nitrogen Compounds, and revisions to the SIP 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 amendments 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 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 (ten megawatts (MW) or less) electric generating units which are registered under a standard permit. Finally, the amendments 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 adopts 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 ADOPTED 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* (26 TexReg 526), 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* (26 TexReg 705), 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. Another table in the TABLES AND GRAPHICS section of that issue of the *Texas Register* (26 TexReg 706), titled "Subcategories - Point Source Potential NO_x Emission Reductions for Houston/Galveston Nonattainment Area Counties," further breaks down the equipment categories and indicates the estimated NO_x emission reductions which would result from implementation of the Chapter 117 rules adopted in December, 2000.

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	Tier 1	2000	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
(hp<11)	Tier 2	2005	7.5 (5.6)		0.80 (0.60)
8#kW<19	Tier 1	2000	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
(11#hp<25)	Tier 2	2005	7.5 (5.6)		0.80 (0.60)
19#kW<37	Tier 1	1999	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
(25#hp<50)	Tier 2	2004	7.5 (5.6)		0.60 (0.45)
37#kW<75	Tier 2	2004	7.5 (5.6)	5.0 (3.7)	0.40 (0.30)
(50#hp<100)	Tier 3	2008	4.7 (3.5)		
75#kW<130	Tier 2	2003	6.6 (4.9)	5.0 (3.7)	0.30 (0.22)
(100#hp<175)	Tier 3	2007	4.0 (3.0)		
130#kW<225	Tier 2	2003	6.6 (4.9)	3.5 (2.6)	0.20 (0.15)
(175#hp<300)	Tier 3	2006	4.0 (3.0)		
225#kW<450	Tier 2	2001	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)
(300#hp<600)	Tier 3	2006	4.0 (3.0)		
450#kW#560	Tier 2	2002	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)
(600#hp#750)	Tier 3	2006	4.0 (3.0)		
kW>560	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 adopted 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 30 TAC 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 adopted 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 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 revisions 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 amendments 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 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 (ten MW or less) electric generating units which are registered under a standard permit. Finally, the amendments 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 changes to §117.10, concerning Definitions, add definitions of "diesel engine," "emergency situation," and “pyrolysis reactor” and renumber subsequent definitions to accommodate the 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, and revise the lead-in paragraph to §117.10 by adding a sentence which notes that additional definitions for terms used in Chapter 117 are found in 30 TAC §101.1 and §3.2, concerning Definitions. This reference is intended as a courtesy to the reader who may not be familiar with the sections in which some definitions are located. Further, the changes to §117.10(2) revise the definition of "applicable ozone nonattainment area" by replacing the wording "pursuant to" with "under" for consistency with the commission’s style guidelines.

In addition, the 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 changes to §117.210, described later in this preamble. As a result of the changes to the definition of "electric power generating system," the commission made revisions to the emissions banking and trading program of Chapter 101, Subchapter H, Division 3, adopted concurrently in this issue of the *Texas Register*. Specifically, the amendments to the figure in 30 TAC §101.353(a), concerning Allocation of Allowances, 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 changes to the definition of "electric power generating system" further add a reference to duct burners used in turbine exhaust ducts for consistency with the new §117.101(4) and the revised §117.106(c)(3), which make the gas turbine ESAD applicable to duct burners used in turbine exhaust ducts.

The 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. In addition, the changes to §117.10 add a reference to minor sources to the definition of "stationary gas turbine" in §117.10(44) for consistency with the change to the definition of "unit" described in the following paragraph.

Finally, the 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 changes will establish new requirements in Subchapter D, Division 2, for stationary gas turbines (including any duct burner in a turbine exhaust duct), so it is necessary to include stationary gas turbines and duct burners in the definition of unit as it applies to minor sources.

The 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 change to §117.103, concerning Exemptions, deletes the exemption for small (ten 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 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 (ten 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 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 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 changes 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 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%. The commission believes that the current rulemaking 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 the Reliant Energy, Incorporated (Reliant) 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.

In any case, the 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 results 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 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 before January 2, 2001, any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, or any limit in a permit by rule under which construction commenced by January 2, 2001.

The 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 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 before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the 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 utility and non-utility 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 utility and non-utility sources in the HGA area.

The alternate ESADs in §117.106(c)(5)(A)(C) were provided by the Business Coalition for Clean Air (BCCA) Appeal Group as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described later in this preamble in the first paragraph of the ANALYSIS OF TESTIMONY section.

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 preamble, was proposed for public comment as a part of that agreement. The commission solicited public comment on the BCCA Appeal Group's proposed alternate ESADs 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. Comments received regarding this issue are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

As noted earlier in this preamble, the TABLES AND GRAPHICS section of the January 12, 2001 issue of the *Texas Register* (26 TexReg 705) included a table titled "Potential NO_x Emission Reductions by Point Source Category for Houston/Galveston Nonattainment Area Counties" which indicates the relative proportion of emissions according to equipment category. Another table in the TABLES AND GRAPHICS section of that issue of the *Texas Register* (26 TexReg 706), titled "Subcategories - Point Source Potential NO_x Emission Reductions for Houston/Galveston Nonattainment Area Counties," further breaks down the equipment categories and indicates the estimated NO_x emission reductions which would result from implementation of the Chapter 117 rules adopted in December, 2000.

In the TABLES AND GRAPHICS section of this issue of the *Texas Register*, the table titled "Potential NO_x Emission Reductions from Alternate ESADs by Point Source Category for Houston/Galveston Nonattainment Area Counties" indicates the relative proportion of emissions according to equipment category and estimated reductions in the event that the alternate ESADs are implemented, as well as the effect of the revisions to the utility boiler ESADs in §117.106(c)(1) and the new diesel engine ESADs in §117.206(c)(9)(D). The commission uses the term "Tier I" to refer to combustion modifications, "Tier II" to refer to flue gas cleanup (i.e., post-combustion control), and "Tier III" to refer to the combination of Tier I and Tier II controls.

Figure 2: 30 TAC Chapter 117 - Preamble

POTENTIAL NO_X EMISSION REDUCTIONS FROM ALTERNATE ESADS* BY POINT SOURCE CATEGORY FOR HOUSTON/GALVESTON NONATTAINMENT AREA COUNTIES - Revised 9/26/01

Category	1997 Emissions (tons per day (tpd))	% of Total Point	Tier III Reductions as adopted on 12/6/00 (%; tpd)	Tier III Reductions as adopted on 9/26/01 (%; tpd)	Tier III Reductions if alternate ESADs are implemented in the future (%; tpd)
Utility Boilers	196.44	29.4	93%; 184 tpd	90%; 176 tpd[1]	86%; 169 tpd[1]
Turbines (+Duct Burners)	155.65	23.3	91%; 141 tpd	91%; 141 tpd	78%; 122 tpd
Heaters and Furnaces	110.12	16.5	88%; 97 tpd	88%; 97 tpd	71%; 79 tpd
IC Engines	86.37	12.9	88%; 75 tpd	89%; 77 tpd[2]	88%; 76 tpd[2]
Industrial Boilers	85.98	12.9	92%; 79 tpd	92%; 79 tpd	89%; 76 tpd
Other	32.99	4.9	59%; 19 tpd	59%; 19 tpd	49%; 16 tpd
Overall Point Source	667.56	100.0	89%; 595 tpd	88%; 588 tpd	81%; 538 tpd

*ESAD = Emission specifications for attainment demonstration

[1]Takes into account the decrease in emission reductions of 7.42 tpd due to the revisions to the utility boiler ESADs in §117.106(c)(1) of this title
[2]Takes into account the 1.12 tpd emission reduction due to the new diesel engine ESADs in §117.206(c)(9)(D) of this title

Another table in the TABLES AND GRAPHICS section of this issue of the *Texas Register*, titled "Subcategories - Point Source Potential NO_x Emission Reductions from Alternate ESADs for Houston/Galveston Nonattainment Area Counties," further breaks down the equipment categories and indicates the estimated NO_x emission reductions which would result in the event that the alternate ESADs are implemented.

Figure 3: 30 TAC Chapter 117 - Preamble

SUBCATEGORIES - POINT SOURCE POTENTIAL NO_X EMISSION REDUCTIONS FROM ALTERNATE ESADS FOR HOUSTON/GALVESTON NONATTAINMENT AREA COUNTIES - Revised 9/26/01

Category	1997 Emissions (tons per day (tpd))	% of Total Point	Number of Units	Tier I Reductions Combustion Modifications	Tier II Reductions Flue Gas Cleanup	Tier III Reductions = Tier I + II	Tier III ESAD Rates
Utility Boilers							
Gas Wall-fired	78.11		16	50%; 39.06 tpd	90%; 70.30 tpd	90%; 70.55 tpd	0.020 lb/MMBtu
Gas Tangential-fired	13.34		5	30%; 4.00 tpd	90%; 12.01 tpd	87%; 11.58 tpd	0.020 lb/MMBtu
Coal Wall-fired	56.92		2	45%; 25.61 tpd	85%; 48.38 tpd	89%; 50.88 tpd	0.040 lb/MMBtu
Coal Tangential-fired	47.78		2	60%; 28.67 tpd	85%; 40.61 tpd	90%; 42.85 tpd	0.040 lb/MMBtu
Auxiliary Boilers	0.29		7	88%; 0.26 tpd	0%; 0 tpd	88%; 0.26 tpd	0.060 lb/MMBtu
Total Utility Boilers	196.44	29.4	32	50%; 97.6 tpd	87%; 172 tpd	90%; 176 tpd	
Turbines and Duct Burners							
Electric Generation	139.06[1]		78	62%; 86.22 tpd	90%; 125.15 tpd	92%;128.22[1] tpd	0.015 lb/MMBtu
Compressors >10MW	4.90		16	61%; 2.99 tpd	90%; 4.41 tpd	93%; 4.58 tpd	0.015 lb/MMBtu
Compressors 1-10MW	6.44		22	60%; 3.86 tpd	90%; 5.80 tpd	90%; 5.80 tpd	0.015 lb/MMBtu
Compressors <1MW	0.42		40	0%; 0 tpd	70%; 0.29 tpd	70%; 0.29 tpd	0.150 lb/MMBtu
Elec. Peaking/Int.	3.16		29	14%; 0.44 tpd	76%; 2.40 tpd	78%; 2.47 tpd	0.015 lb/MMBtu
Test Cell	0.52		4	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Chemical Processing	1.13[1]		2	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Emergency	0.02		2	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Total Turbines/DBs	155.65	23.3	193	60%; 93.51 tpd	89%; 138.05 tpd	91%; 141 tpd	
Process Heaters/Furnaces							
Gas-fired $100 MMBtuh	88.16		424	49%; 43.20 tpd	90%; 79.35 tpd	90%; 79.35 tpd	0.010 lb/MMBtu
Gas-fired $40<100MMBtuh	14.93		216	49%; 7.32 tpd	86%; 12.84 tpd	86%; 12.84 tpd	0.015 lb/MMBtu
Gas-fired <40 MMBtuh	6.98		726	62%; 4.33 tpd	0%; 0 tpd	62%; 4.33 tpd	0.036 lb/MMBtu
Oil-fired	0.05		1	33%; 0.02 tpd	85%; 0.04 tpd	90%; 0.04 tpd	2 lb/M gal
Total Process Heaters	110.12	16.5	1367	50%; 54.87 tpd	84%; 92.23 tpd	88%; 96.56 tpd	

Category	1997 Emissions (tons per day (tpd))	% of Total Point	Number of Units	Tier I Reductions Combustion Modifications	Tier II Reductions Flue Gas Cleanup	Tier III Reductions = Tier I + II	Tier III ESAD Rates
IC Engines							
Lean-burn Gas	62.15		302	70%; 43.51 tpd	90%; 55.94 tpd	93%; 57.69 tpd	0.50 g/hp-hr
Rich-burn Gas	18.56		158	0%; 0 tpd	97%; 17.94 tpd	97%; 17.94 tpd	0.17 g/hp-hr
Emergency Diesel	5.4		196	20%; 1.08 tpd	0%; 0 tpd	20%; 1.08 tpd	various
Other Diesel	0.20		10	20%; 0.04 tpd	0%; 0 tpd	20%; 0.04 tpd	various
Test Cell	0.08		16	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Dual-fuel	0.02		1	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	5.83 g/hp-hr
Emergency Gas	0.02		15	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Total IC Engines	86.37	12.9	699	52%; 44.63 tpd	86%; 73.88 tpd	89%; 76.75 tpd	
Industrial Boilers							
Gas-fired $100 MMBtuh	55.46		180	60%; 33.28 tpd	90%; 49.91 tpd	96%; 53.24 tpd	0.010 lb/MMBtu
RCRA BIF $100 MMBtuh	11.24		21	0%; 0 tpd	82%; 9.22 tpd	82%; 9.22 tpd	0.015 lb/MMBtu
RCRA BIF <100 MMBtuh	1.04		20	0%; 0 tpd	54%; 0.56 tpd	54%; 0.56 tpd	0.030 lb/MMBtu
Petroleum Coke-fired	11.60		1	0%; 0 tpd	90%; 10.44 tpd	90%; 10.44 tpd	0.057 lb/MMBtu
Gas $40 <100 MMBtuh	3.48		90	0%; 0 tpd	87%; 3.03 tpd	87%; 3.03 tpd	0.015 lb/MMBtu
Gas-fired <40 MMBtuh	1.60		235	62%; 0.99 tpd	0%; 0 tpd	62%; 0.99 tpd	0.036 lb/MMBtu
Wood-fired	1.01		3	0%; 0 tpd	78%; 0.79 tpd	78%; 0.79 tpd	0.046 lb/MMBtu
Rice Hull-fired	0.51		1	0%; 0 tpd	90%; 0.46 tpd	90%; 0.46 tpd	0.089 lb/MMBtu
Oil-fired	0.14		3	0%; 0 tpd	90%; 0.13 tpd	90%; 0.13 tpd	2 lb/M gal
Total Industrial Boilers	85.98	12.9	554	40%; 34.31 tpd	87%; 74.54 tpd	92%; 78.86 tpd	

Category	1997 Emissions (tons per day (tpd))	% of Total Point	Number of Units	Tier I Reductions Combustion Modifications	Tier II Reductions Flue Gas Cleanup	Tier III Reductions = Tier I + II	Tier III ESAD Rates
Other							
Refinery Cat Crackers	14.93		13	0%; 0 tpd	90%; 13.44 tpd	90%; 13.44 tpd	13 ppmv @0%O_2
Incinerators $40 MMBtuh	4.02		23	0%; 0 tpd	80%; 3.22 tpd	80%; 3.22 tpd	0.030 lb/MMBtu
Incinerators <40 MMBtuh	1.93		247	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Flares	5.37		555	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Dryers - $MgCl_2$	1.05		1	0%; 0 tpd	90%; 0.95 tpd	90%; 0.95 tpd	10% of ‘97 rate
Dryers - Others	1.26		119	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Pulping Recovery Furnaces	1.71		3	0%; 0 tpd	64%; 1.09 tpd	64%; 1.09 tpd	0.05 lb/MMBtu
Steel Furnace $20 Ht Treat	0.17		4	35%; 0.06 tpd	0%; 0 tpd	35%; 0.06 tpd	0.09 lb/MMBtu
Steel Furnace $20 Reheat	0.66		5	50%; 0.33 tpd	0%; 0 tpd	50%; 0.33 tpd	0.06 lb/MMBtu
Steel Furnace <20MMBtuh	0.16		78	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Kilns - Lime	0.28		2	64%; 0.17 tpd	0%; 0 tpd	64%; 0.17 tpd	0.66 lb/ton CaO
Kilns - Lightweight Agg.	0.42		3	30%; 0.13 tpd	0%; 0 tpd	30%; 0.13 tpd	0.76 lb/ton LWA
Kilns - Other	0.08		14	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Nitric Acid	0.41		3	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Ovens	0.23		60	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Vents	0.18		49	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Miscellaneous	0.12		150	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Fugitives	0.01		6	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Total Other	32.99	4.9	1334	2%; 0.69 tpd	57%; 18.70 tpd	59%; 19.39 tpd	

[1]Corrections from the corresponding table in the January 12, 2001 issue of the *Texas Register*

In addition, the 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 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 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 changes to §117.107, concerning Alternative System-wide Emission Specifications, revise §117.107(a) to update a reference to the renumbered §117.10(13), spell out the abbreviation for the term "MMBtu" in §117.107(a)(3), and abbreviate the term "lb/MMBtu" in §117.107(b)(1) - (3).

The changes to §117.108 and §117.138, concerning System Cap, revise §117.108(b) and §117.138(b) by updating references to the renumbered §117.10(13). The 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 30 TAC Chapter 116 and start of construction of EGFs under a 30 TAC Chapter 106 permit by rule. This date is consistent with §101.353. The 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.

In addition, the changes to §117.108 revise §117.108(c)(1) by modifying the method of determining level of activity for new EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in 30 TAC §101.350, concerning Definitions. The 180-day adjustment period addresses that period of time from first start-up to establishment of normal operating conditions for a new facility.

In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period. A principal goal is to provide incentive to make emissions reductions. The commission believes that owners or operators who install and operate cleaner equipment should have the opportunity to fully integrate that equipment at a realistic level of operation that is representative of the demands that will be placed on the equipment. The commission believes that a five-year period to establish a baseline will allow this integration, while timely establishing the necessary emissions cap. This is consistent with the corresponding revisions to

§101.353 which add the option of a five-year period to establish a baseline and the availability of an additional two-year period in extenuating circumstances.

The 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 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 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 change will clarify that the 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 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 changes to §117.119 also revise §117.119(e)(5) by replacing the wording "pursuant to" with "in accordance with" for consistency with the commission's style guidelines.

The 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 to be exempt 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 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 new §117.10(14). However, operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average. Fifty-two hours per year allows 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 30 TAC §116.10, concerning General Definitions, and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in 30 TAC §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account.

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 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 changes to §117.203 revise §117.203(a)(10) for consistency with the 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 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 §116.10 and 40 CFR §60.15, respectively, and the term “relocated” means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account.

The 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, in non-emergency situations. This allows operation of stationary diesel engines during an emergency situation for as many hours as the emergency situation, as defined in §117.10(14), continues to exist. 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 §116.10 and 40 CFR §60.15, respectively, and the term “relocated” means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account.

In addition, the 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, was deleted because it is redundant.

Finally, the changes to §117.203 delete the exemption in §117.203(c) for small (ten 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 (ten 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 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 before January 2, 2001, any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, 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 changes to §117.206(c)(2)(B), (3)(B)(ii), and (16)(A) are necessary because of, and are consistent with, the new 30 TAC §101.354(b), concerning Allowance Deductions, that the commission added to the emissions banking and trading program of Chapter 101, Subchapter H, Division 3, concurrently in this issue of the *Texas Register*.

The 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 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 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 4: 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 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 before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the 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 utility and non-utility 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 utility and non-utility sources in the HGA area.

The alternate ESADs in §117.206(c)(18)(A) - (Q) were provided by the BCCA Appeal Group as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described later in this preamble in the first paragraph of the ANALYSIS OF TESTIMONY section, with the exception of the alternate ESAD for wood-fired boilers which is described later in this preamble under the heading of *ESAD - WOOD-FIRED BOILERS* in the ANALYSIS OF TESTIMONY section.

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 preamble, was proposed for public comment as a part of that agreement. The commission solicited public comment on the BCCA Appeal Group's proposed alternate ESADs 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. Comments received regarding this issue are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

The 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 change will give the owners and operators of EGFs in HGA additional flexibility in meeting their system caps.

In addition, the 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 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 language allows 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, and the maximum rated capacity authorized by the permit issued on or after January 2, 2001 is no less than the maximum rated capacity represented in the permit application as of January 2, 2001. 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 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. In another example, a unit that is classified as a stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, shall be classified as a stationary gas-fired engine for the purposes of Chapter 117. The new §117.206(h)(2) is necessary to ensure that the intended emission reductions of the program are achieved and to clarify how units which can be classified as multiple unit types are treated in Chapter 117.

Finally, the changes to §117.206 revise §117.206(h)(3), which prohibits the owner or operator of units which combust fuel or waste streams containing chemical-bound nitrogen from directing these streams to flares or other units which are not subject to an ESAD. This is necessary to prevent circumvention due to the transfer of emissions associated with chemical-bound nitrogen from a unit under which these emissions would be controlled (i.e., a unit subject to an ESAD) to a unit that is not subject to the mass emissions cap and trade program (i.e., a unit without an ESAD) and therefore is uncontrolled. Section §117.206(h)(3) has been revised to make this intent clear. Also, the current §117.206(h)(3)(A) and (B) were deleted because the mass emissions cap and trade program does not include a provision allowing the opt-in of units to the program.

The 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. Section 117.206(i) allows operation for specific manufacturer's recommended testing requiring a run of over 18 consecutive hours, or to verify reliability of emergency equipment (e.g., emergency generators or pumps) immediately after unforeseen repairs. Routine maintenance such as an oil change is not considered to be an unforeseen repair since it can be scheduled outside the 6:00 a.m. to noon time period.

The changes to §117.210, concerning System Cap, modify the system cap requirements by adding another option to the last two sentences of §117.210(a). The new language excludes each EGF that generates electricity primarily for internal use, but that during 1997 and all subsequent calendar years transferred (or will transfer) that generated electricity to a utility power distribution system at a rate less than 3.85% of its actual electrical generation (which represents two weeks' worth of electrical generation per calendar year). These EGFs are base load units and are not operated at higher levels on hot summer days to meet electric demand and would not contribute additional emissions during these periods. Therefore, the commission believes it is appropriate to exclude these units from the system cap.

The changes to §117.210 also 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 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 EGFs at industrial, commercial, and institutional combustion sources in HGA. In addition, the 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 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 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 change allows the owner or operator to substitute the system highest 30-day period in the nine months comprising the highest three consecutive months in each year of the 1997 - 1999 period. The existing §117.210(c)(2) is renumbered to become a new §117.210(c)(3).

In addition, the changes to §117.210 revise the rolling 30-day average emission cap of §117.210(c)(1), applicable during July - September, by modifying the method of determining level of activity for new EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in §101.350. The 180-day adjustment period addresses that period of time from first start-up to establishment of normal operating conditions for a new facility. In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period. A principal goal is to provide incentive to make emissions reductions. The commission believes that owners or operators who install and operate cleaner equipment should have the opportunity to fully integrate that equipment at a realistic level of operation that is representative of the demands that will be placed on the equipment. The commission believes that a five-year period to establish a baseline will allow this integration, while timely establishing the necessary emissions cap. This is consistent with the corresponding revisions to

§101.353 which add the option of a five-year period to establish a baseline and the availability of an additional two-year period in extenuating circumstances.

Finally, the changes to §117.210 revise the rolling 30-day average emission cap of §117.210(c)(2), applicable during months other than July - September, by modifying the method of determining level of activity for new EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. For an EGF for which the system highest 30-day period in the first two years of operation occurs in months other than July - September, the owner or operator may substitute the system highest 30-day period in the six months comprising the highest three consecutive months in any two consecutive years in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in §101.350. The 180-day adjustment period addresses that period of time from first start-up to establishment of normal operating conditions for a new facility. In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period. A principal goal is to provide incentive to make emissions reductions. The commission believes that owners or operators who install and operate cleaner equipment should have the opportunity to fully integrate that equipment at a realistic level of operation that is representative of the demands that will be placed on the equipment. The commission believes that a five-year period to establish a baseline will allow this integration, while timely establishing the necessary emissions cap. This is consistent with the corresponding revisions to §101.353 which add the option of a five-year period to establish a baseline and the availability of an additional two-year period in extenuating circumstances.

The 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 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 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 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. Finally, the changes to §117.213 also revise §117.213(l) by replacing the wording "pursuant to" with "under" for consistency with the commission’s style guidelines.

The 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)(6)(D), (11), or (12). This change is necessary to facilitate recordkeeping to ensure that operation for testing or maintenance purposes is limited to 52 hours per year, based on a rolling 12-month average, and to document that all other engine operation occurs only during emergency situations, as defined in §117.10. The existing language becomes §117.214(a)(1) as a result of the addition.

The 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, the 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 restriction on operating hours for testing and maintenance and revise §117.219(f)(6) to add a reference to the engine exemptions of §117.203(a)(6)(D), (11), or (12) described earlier in this preamble. The changes to §117.219 also revise §117.219(f)(6) by adding a requirement that the owner or operator keep records of the purpose of engine operation, and if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation.

The 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 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 by 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 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 new §117.10(14). However, operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average. Fifty-two hours per year allows 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 §116.10 and 40 CFR §60.15, respectively, and the term “relocated” means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account. 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 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 new §117.203(a)(11) described earlier in this preamble. The 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 §116.10 and 40 CFR §60.15, respectively, and the term “relocated” means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account. In addition, the 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 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 §116.10 and 40 CFR §60.15, respectively, and the term “relocated” means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account.

In addition, the 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 changes to §117.473 also delete the exemption in §117.473(c) for small (ten 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 (ten 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 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, any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, or any limit in a permit by rule under which construction commenced by January 2, 2001. The 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 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).

In addition, the changes to §117.475 revise §117.475(c) to clarify that the NO_x emission specifications of §117.475 shall be used in conjunction with §117.475(a) to determine allocations for the mass emissions cap and trade program of Chapter 101, or in conjunction with §117.475(b) to establish unit-by-unit emission specifications, as appropriate. This change is necessary because the existing language could give the impression that all units must meet the NO_x emission specifications of §117.475 on a unit-by-unit basis.

The 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 remains 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 changes to §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 revisions, and the reference to paragraphs (1) - (2) is revised to reference paragraphs (1) - (5).

The 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 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% oxygen (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 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 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. Finally, the changes to §117.475 add new subsections (d) - (f) in order to address circumvention issues. These new subsections for minor sources are consistent with §117.206(h) for major sources.

The 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 revision to the definition of this term in §117.10.

The 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. Section 117.478(c) allows operation for specific manufacturer's recommended testing requiring a run of over 18 consecutive hours, or to verify reliability of emergency equipment (e.g., emergency generators or pumps) immediately after unforeseen repairs. Routine maintenance such as an oil change is not considered to be an unforeseen repair since it can be scheduled outside the 6:00 a.m. to noon time period.

The 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 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)(E) and (I) to require records of hours of operation for stationary diesel engines claimed exempt based on low annual hours of operation or use exclusively in emergency situations. The changes to §117.479 also revise §117.479(h) by adding a requirement that the owner or operator keep records of the purpose of engine operation, and if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation. Finally, the record retention time of §117.479(h) was revised from two years to five years for consistency with §117.479(f) and (j).

In addition, the changes to §117.479 add a new §117.479(i), which requires run time meters for stationary diesel engines claimed exempt due to low annual hours of operation or use exclusively in emergency situations. For engines claimed exempt due to low annual hours of operation, this change is necessary to facilitate recordkeeping to document that the engines qualify for the exemption. For engines operated exclusively in emergency situations, this change is necessary to facilitate recordkeeping to ensure that operation for testing or maintenance purposes is limited to 52 hours per year, based on a rolling 12-month average, and to document that all other engine operation occurs only during emergency situations, as defined in §117.10. The changes to §117.479 also 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 restriction on operating hours for testing and maintenance.

The 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)). The changes to §117.510 also revise §117.510(a)(1)(A)(i) and (c)(1)(A)(i) by replacing the wording "pursuant to" with "under" for consistency with the commission's style guidelines, and revise §117.510(c)(2)(A)(ii)(II) by replacing the wording "pursuant to" with "in accordance with," also for consistency with the commission's style guidelines.

In addition, the 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 clarify that if flue gas cleanup (such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR)) is installed, then the emissions monitors required by §117.114 must be installed at the time of installation of flue gas cleanup or by March 31, 2005 (whichever occurs first), regardless of whether or not combustion controls are later installed. If only combustion controls are installed on a unit, then the emissions monitors required by §117.114 must be installed by March 31, 2005. If installation of emission controls (whether combustion controls, flue gas cleanup, or both) has not begun by March 31, 2005 on a unit for which §117.114 requires emissions monitors, then the required emissions monitors must be installed by March 31, 2005.

The 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 30 TAC §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 changes.

Additionally, the percent reductions in the renumbered §117.510(c)(2)(B)(iii)(I) and (II) were changed from 46% and 92% to 47% and 95%, respectively. The 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 adopted 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 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 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 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)). The changes to §117.520 also revise §117.520(c)(2)(A)(ii)(I), (C)(i), and (D)(i) by replacing the wording "pursuant to" with "in accordance with" for consistency with the commission’s style guidelines.

In addition, the 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 clarify that if flue gas cleanup (such as SCR or SNCR) is installed, then the emissions monitors required by §117.214 must be installed at the time of installation of flue gas cleanup or by March 31, 2005 (whichever occurs first), regardless of whether or not combustion controls are later installed. If only combustion controls are installed on a unit, then the emissions monitors required by §117.214 must be installed by March 31, 2005. If installation of emission controls (whether combustion controls, flue gas cleanup, or both) has not begun by March 31, 2005 on a unit for which §117.214 requires emissions monitors, then the required emissions monitors must be installed by March 31, 2005.

The changes to §117.520 also revise the system cap 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 changes to §117.520(c)(2)(B)(iii) would allow smaller annual reductions in emissions spread over a five-year period. The commission adopted this change to allow the affected industries more options for planning and implementing incremental reductions in emissions. The amendment will not affect the March 31, 2007 final compliance date nor will it increase final emission rates, and it will still achieve the final emission reductions as required by the SIP.

Further, the 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 changes to §117.520 delete an incorrect reference to non-EGFs in existing §117.520(c)(2)(D), renumbered as §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 renumbered as §117.520(c)(2)(D).

Finally, the 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 changes 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 clarify that if flue gas cleanup (such as SCR or SNCR) is installed, then the emissions monitors required by §117.479 must be installed at the time of installation of flue gas cleanup or by March 31, 2005 (whichever occurs first), regardless of whether or not combustion controls are later installed. If only combustion controls are installed on a unit, then the emissions monitors required by §117.214 must be installed by March 31, 2005. If installation of emission controls (whether combustion controls, flue gas cleanup, or both) has not begun by March 31, 2005 on a unit for which §117.479 requires emissions monitors, then the required emissions monitors must be installed by March 31, 2005.

In addition, the changes to §117.534 also revise §117.534(1)(B)(i) and (C)(i) and (2)(B)(i) by replacing the wording "pursuant to" with "in accordance with" for consistency with the commission's style guidelines. The 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 revisions 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 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) allows 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 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 adopts 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.

FINAL 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. A "major environmental rule" means a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure and that may adversely affect in a material way the economy, 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 (ten 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 sites in the HGA ozone nonattainment area with a collective design capacity to emit (from units with ESADs) NO_x in amounts greater than or equal to ten tpy, as well as stationary diesel and dual-fuel engines at sites with a collective design capacity 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 in the rule proposal preamble, including the discussion in the PUBLIC BENEFIT AND COSTS section of the proposal (26 TexReg 4400). 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.

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 adopted 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.

No comments were received during the comment period regarding the draft RIA determination.

TAKINGS IMPACT ASSESSMENT

The commission evaluated this rulemaking action and performed an analysis of whether the adopted 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 adopted 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 adopted 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. No comments were received during the public comment period regarding the CMP consistency review.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: June 13, 2001, in Galveston; June 14, 2001 in Rosenberg and Houston; June 15, 2001, in Austin; and July 2, 2001 in Houston. The comment period closed on July 2, 2001.

Twenty-eight commenters submitted testimony on the proposal. Harris County Municipal Utility District 368 and Shrader Engineering Company submitted joint oral comments and will be referred to as Shrader. Texas Instruments (TI) supported the proposed revisions to Chapter 117. Abitibi-Consolidated Inc. (Abitibi); Baker Botts L.L.P. on behalf of Texas Industry Project (TIP); BASF Corporation (BASF); BP Amoco (BP); BCCA; BCCA Appeal Group (BCCAAG); City of Houston (Houston); Dow Chemical Company (Dow); Dynegy, Incorporated (Dynegy); Energy Developments, Incorporated (EDI); Environmental Defense (ED); Environmental Resources Management (ERM); EPA; ExxonMobil Corporation (ExxonMobil); Galveston-Houston Association for Smog Prevention (GHASP); Haldor Topsoe, Incorporated (Topsoe); IT Corporation (IT); National Aeronautics and Space Administration (NASA); Reliant; Safety-Kleen (Deer Park), Incorporated (Safety-Kleen); Sempra Energy Resources (Sempra); Shrader; Sierra Club - Houston Regional Group (Sierra-Houston); Texas Chemical Council (TCC); Texas Department of Transportation (TxDOT); Thermal Energy Cooperative (TECO); and an individual supported the proposed revisions but suggested changes or clarifications.

BCCAAG supported the comments submitted by TIP. Dow supported the comments submitted by BCCA and TIP. Dynegy supported the comments submitted by BCCAAG.

ANALYSIS OF TESTIMONY

In January 2001, BCCAAG and others filed suit against the commission challenging the December 6, 2000 SIP revision for HGA and five of the ten sets of rules associated with that SIP revision. As part of that lawsuit, the plaintiffs sought a temporary injunction to stay the effectiveness of these five sets of rules and for the commission to withdraw the SIP from EPA consideration. A hearing on this request was held before Judge Margaret Cooper, Travis County District Court, Texas, on May 14 - 18, 2001. Before that hearing was completed, an agreement in principle was reached to settle the lawsuit, and a Consent Order was entered by Judge Cooper which includes certain specific items included in the SIP revision and rules in Chapters 101 and 117 proposed by the commission on May 30, 2001 (see the June 15, 2001 issue of the *Texas Register* (26 TexReg 4380 and 4400, respectively)). In support of its position that certain testimony in that hearing establishes the infeasibility of the NO_x reduction and that the air dispersion modeling used by the commission is not reliable, BCCAAG submitted the transcript from the hearing as comments on these proposals. Although the hearing was not completed before a settlement in principle was reached, the hearing transcript included testimony from BCCAAG's witnesses as well as the commission's witnesses, and therefore presents both sides of, or two different opinions on, some of the issues. Many of the documents introduced as exhibits in the hearing predate the rule changes and SIP revision proposed by the commission in the June 15, 2001 issue of the *Texas Register* and do not specifically address these rule changes and SIP revision. In addition, BCCAAG submitted as

comments its First Amended Petition in the lawsuit and BCCA's comments from the earlier SIP, both of which were created before the settlement in principle was reached. While BCCAAG supports the substitution of new ESADs and other rule language from the Consent Order, it is not clear as to what other specific changes to the SIP and rules should be considered in this adoption in response to these particular comments.

GENERAL COMMENTS

TI supported the proposed revisions to Chapter 117.

The commission appreciates the support.

BCCA and ED resubmitted their September 25, 2000 comment letters concerning rulemakings and the associated SIP revision which were adopted by the commission on December 6, 2000, while BCCAAG incorporated by reference the September 25, 2000 BCCA comment letter. BCCA and ED had initially submitted these comment letters during the comment period for these previous rulemakings and associated SIP revision. BCCAAG also resubmitted a September 25, 2000 comment letter from Enterprise Products Operating L.P. (Enterprise) concerning rulemakings and associated SIP revision which were adopted by the commission on December 6, 2000. Enterprise had initially submitted this comment letter during the comment period for these previous rulemakings and associated SIP revision.

The comments in the BCCA, ED, and Enterprise comment letters dated September 25, 2000 were addressed in the ANALYSIS OF TESTIMONY sections of the preambles to these earlier

rulemakings and SIP revisions which were published in the January 12, 2001 issue of the *Texas Register*.

Sierra-Houston referenced, but did not submit, 24 letters, two memoranda, and one paper dated from August 2, 1999 through February 23, 2001 which it reported as being information previously submitted to the commission. Sierra-Houston requested that this information be considered during the current rulemakings and SIP revisions. One individual referenced but did not submit previous letters addressing Houston SIP issues.

Sierra-Houston and the one individual did not identify the relationship between its previous submissions and any rulemaking or SIP revision for which it had previously submitted the referenced 24 letters, two memoranda, and one paper. Consequently, it is unclear whether this information had been submitted during the comment period for previous rulemakings and SIP revisions, and if so, which ones, or whether this information had been submitted in a manner unrelated to proposed rulemaking, and if so, the project(s) for which the information was submitted in order to allow the commission to locate the information. If Sierra-Houston and the individual submitted this information during the comment period for previous rulemakings and SIP revisions, then it was addressed in the ANALYSIS OF TESTIMONY section of the preambles to the earlier rulemakings and SIP revisions which were published in previous issues of the *Texas Register*. If, however, Sierra-Houston and the individual had not submitted this information during the comment period for previous rulemakings and SIP revisions, then it

is unclear how the commission is to respond to this information without this information available to the commission during the comment period for the current rulemakings and SIP revisions.

TECHNICAL FEASIBILITY - GENERAL COMMENTS

As discussed earlier in this preamble, BCCAAG submitted the entire transcript of the May 14 - 18, 2001 temporary injunction hearing held before Judge Margaret Cooper, Travis County District Court, concerning the lawsuit styled BCCA Appeal Group, et al v. TNRCC. Regarding technical feasibility of meeting the existing ESADs, a witness, Doug Deason (Deason), testified that there is "extensive" experience with combustion modifications to reduce NO_x, both in the United States and in other countries.

The commission agrees that the frame of reference for retrofit experience is not limited to the United States, and that there is extensive experience with combustion modifications to reduce NO_x.

BCCA and BCCAAG expressed doubts about the technical feasibility of the 90% reductions of the existing ESADs which were adopted December 6, 2000. BCCA and BCCAAG stated that "in sworn testimony admitted into evidence in the pending litigation, duly qualified experts have further established the infeasibility of the 90% reduction" and that the existing ESADs should be removed from the SIP in favor of alternate ESADs which would achieve an 80% NO_x reduction from point sources. A witness, Randy Hamilton, (Hamilton), testified that the technical feasibility of the point source rule is not uncertain, but that "it is technically feasible to achieve the point source reductions required by the rule." Hamilton further testified that he believes that "the technical feasibility determinations come down to cost feasibility... on individual units."

The commission disagrees with the commenters and agrees with Hamilton. In the December 2000 adoption of the existing ESADs to achieve approximately 90% reductions in NO_x point source emissions, the commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of the existing ESADs. The commission determined that the various controls which can be used to meet the ESADs have a proven performance experience and agreed with BP that the 90% reductions are technically feasible. A detailed explanation of how the commission reached these conclusions is given in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524). BCCA and BCCAAG are mistaken in their claim that "duly qualified experts have further established the infeasibility of the 90% reduction." In fact, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, Judge Margaret Cooper, Travis County District Court, has not even heard all of the testimony in the May 14 - 18, 2001 temporary injunction hearing, and obviously has not issued a ruling on the temporary injunction requested by BCCAAG, et al. Further, the trial on the merits of the case has not even begun. The commission is confident that if and when litigation resumes, the evidence will demonstrate that the existing ESADs which were adopted December 6, 2000 are technically feasible.

Deason testified that with good design of new units, combustion controls "typically get very close to achieving vendors' guarantees and the maximum potential of the equipment."

The commission agrees that good design is critical to achieving the desired emission reductions.

Deason testified that in some cases, the optimum burner is not available and as a result, the unit may not achieve the technology potential of burner retrofits.

Combustion controls are developing dynamically, achieving teen and even single digit NO_x ppm in a growing number of applications. For example, an external gas conditioning system can be added which introduces inert gas using existing fuel pressure (i.e., without moving parts) into an eductor where it dilutes the fuel to produce a low-NO_x fuel. The inert gas reduces peak flame temperatures, lowers available O_2 concentration, and minimizes reaction times, thereby reducing both prompt NO_x and thermal NO_x formation. Under demonstration on a utility boiler in Collin County, Texas, this is currently achieving 0.04 lb/MMBtu, with expectations of even better performance. Other control options are also available. Burner replacement is but one of many combustion control options.

There undoubtedly will be cases in which an owner or operator evaluates the circumstances of a particular unit and determines, for whatever reason, to pursue an option other than retrofit

control technology. For example, replacement or consolidation of existing equipment, reduced fuel firing, and shutdown of existing equipment (particularly for marginally economic equipment and production lines) are possible options for reducing NO_x. The owner or operator of each affected source is free to choose the control technology which best addresses the circumstances of the affected sources, obtain additional allowances from another facility's surplus allowances, or select a combination of the two approaches.

Deason testified that ExxonMobil plants in other ozone nonattainment areas (Baton Rouge, Southern California, etc.) have units that have been retrofitted with Tier I controls, and none are meeting the ESADs. Another witness, Jess McAngus (McAngus), testified that Tier I controls alone are insufficient to meet the ESADs.

Because of Houston's unique circumstances, it is unlikely that another nonattainment area will require as large a point source reduction. The reductions required to meet the standard depend on the number and degree of exceedances. Currently, only Los Angeles has ozone exceedances in number and degree similar to Houston's. The intensity of summertime sunlight is also a factor, which puts cities in southern latitudes like Los Angeles and Houston at a disadvantage in comparison to more northern cities. Singularly, Houston has the highest percentage of point source NO_x emissions of total NO_x emissions of the nine severe and one extreme ozone nonattainment areas in the United States. Therefore, it is no surprise that the ESADs are in many cases more stringent than the emission specifications in areas such as

Baton Rouge, which is classified as a serious ozone nonattainment area (as compared to Houston's classification as a severe ozone nonattainment area), or southern California, which has a lower percentage of point source NO_x emissions than Houston.

As noted in the preamble to the Chapter 117 revisions which were proposed in the August 25, 2000 issue of the *Texas Register*, the emission specifications are expected to necessitate SCR on most units. The commission never expected or represented that all emission specifications could be met solely with combustion controls. In fact, in the August 25, 2000 rule proposal preamble the commission specifically delineated which source categories it expected would need to install post-combustion controls to meet the ESADs (see the August 25, 2000 issue of the *Texas Register* (25 TexReg 8287 - 8292 and 25 TexReg 8480 - 8482)).

Point source NO_x reductions in the range of 90% require the combined use of combustion modification controls (Tier I) and flue gas clean up controls (Tier II) on the majority of large combustion units. This combination of controls is referred to as Tier III. The ESADs for many units are not based on Tier I, but rather are based on Tier III. Deason did not indicate what emission specification the units at ExxonMobil plants in other ozone nonattainment areas were designed to achieve. If the units were specifically designed to meet a less stringent requirement, it would not be logical to expect that the units would necessarily meet a more stringent ESAD.

The capabilities of combustion modifications are well documented in the literature, including the NO_x control literature cited in the cost note sections of the preamble to the Chapter 117 revisions which were proposed in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275). These documents report combustion based reductions from minimal to over 90%. Reduction capabilities as reported in the literature continue to improve. Theoretically, combustion modifications are capable of a 90% reduction, and in recent practice, a few low-NO_x burner retrofits in commercial operation are achieving this level. The basic principles of NO_x formation have been understood since the 1940s when Zeldovich developed the chemical mechanism for NO_x formation which explained its dependence on temperature in a flame. Some NO_x reduction efforts date back to the 1950s.

Today's understanding of NO_x formation includes three different mechanisms for generation of NO_x. Thermal NO_x is formed by the oxidation of atmospheric nitrogen present in the combustion air. Prompt NO_x is produced by high speed reactions at the flame front. Fuel NO_x is formed by the oxidation of nitrogen contained in the fuel. Prompt NO_x is more likely to form in a fuel-rich environment because of its dependence on hydrocarbon fragments. This is very different than thermal NO_x, which is highly dependent upon air concentrations.

Because the temperature requirements of commercial processes are in most cases lower than the temperatures at which most NO_x forms, low-NO_x combustion development will continue to approach the single digit NO_x ppm reflected in the existing ESADs. In fact, one vendor has

provided several dozen retrofits, primarily on gas-fired boilers in commercial service today, achieving NO_x levels of nine ppm or less. Another vendor provided a list of 12 boilers in California, ranging in size from 21 to 70 MMBtu/hr, which it equipped with low-NO_x burners achieving NO_x levels of nine ppm or less. Five of the 12 boilers were retrofits, ranging in size from 21 to 64 MMBtu/hr. However, the vendor has stated (and the vendor's data supports) that its low-NO_x burners can achieve NO_x levels of nine ppm or less on both new boilers and retrofits. These applications represent one end of a spectrum of capabilities of low-NO_x combustion retrofits.

Combustion technology continues to develop rapidly since the late 1980s when a number of California districts set retrofit NO_x control standards. The literature of the early 1990s cites combustion technology retrofit capabilities of 50% - 75% reductions on gas-fired boilers; today, 60% reduction is being achieved on one of the coal-fired electric utility boilers in Houston through retrofitting with low-NO_x combustion technology. Many of the units in low-NO_x operation today were retrofit in the early 1990s because of SIP limits that were set in the late 1980s in areas such as SCAQMD, Ventura County Air Pollution Control District (VCAPCD), and the Bay Area Air Quality Management District (BAAQMD) in California. Both combustion modifications and flue gas cleanup are established technologies which are documented in the NO_x control literature, including the EPA alternative control techniques (ACT) guidance documents, papers at numerous meetings of research and trade organizations for industry, NO_x control vendors, constructors, and the government. The number of low-NO_x

applications has grown steadily worldwide since the early 1990s as a number of other countries also have addressed problems related to NO_x emissions, including smog and acid deposition. During the 1990s, the capabilities of NO_x technology advanced and a solid experience base was created. This may be why there is lack of consensus among the owners or operators of major sources on the technical feasibility of the ESADs and why the vendor community views these limits as technically feasible.

Deason testified that Tier I for one point source is not very transferrable to another because each unit is different, with different spacing between equipment and different duty requirements. Deason stated that an individual engineering design analysis is necessary and commented that as an example, ExxonMobil has over 20 different types of ethylene plant pyrolysis reactors. Deason stated that the same principle of individual engineering design analysis applies to ExxonMobil's process heaters and furnaces, gas turbines, and boilers. Hamilton testified that one person's opinion is that while 800 units may require flue gas cleanup, only a lesser number of designs (perhaps 100) will be necessary because among all of these units there is a certain number of essentially very similar looking units, and this commonality will reduce the number of detailed engineering studies necessary.

The commission agrees that detailed engineering design analysis is necessary. The commission also agrees that the commonality between some units is expected to reduce the number of detailed engineering studies necessary.

Deason testified that field experience has not adequately demonstrated that retrofit Tier III technology will meet the ESADs. McAngus testified that Tier II controls alone are insufficient to meet the ESADs, and that Tier III controls alone are insufficient to meet the ESADs. Hamilton testified that "the patents for SCR were issued in the 1950s. Commercial use of SCR goes back at least to the 1970s in Japan, and expanded greatly in Japan and West Germany... in the 1980s. SCR began to be commercially demonstrated in the United States during the second half of the 1980s, and it continues to grow rapidly in the United States, as more... new units and existing units have SCR applied." Hamilton also testified that "in 1997 the Institute of Clean Air Companies counted more than 500 {SCR} units operating worldwide. More recently, I understand that one company has an experience list of about 500 units in the United States right now." Hamilton further testified that "in Europe there are more than 500 diesel engines with SCR," and some of these are retrofits. Hamilton also testified that the relatively limited number of retrofitted SCRs is not a concern because "the retrofits are technically feasible, and what we have seen, in looking at the history of... air emission controls over the years is that application of technology to a given level follows the regulations, rather than the other way around. When the emission standards are set at a particularly stringent level, technology has responded and new examples {of units meeting the emission standards} appear." Hamilton testified that in the five major source categories, the commission found examples of equipment retrofitted to achieve the ESADs, representing more than 95% of the emissions, although the commission did not identify examples of retrofits for all of the different subcategories of point sources. Hamilton also testified that for a number of major categories, the commission was aware of examples of retrofitted units which were controlled to at or below the ESADs.

As noted in the response to a previous comment, the capabilities of Tier I combustion modifications are well documented. From the standpoint of establishing the technical feasibility of the Tier II reductions, there is no worldwide lack of retrofit experience. SCR is the basic Tier II flue gas NO_x control technology. Most of the reductions achieved by SCR have come from retrofit applications. Also, technology is replicable so, in a true sense, the first successful SCR project was sufficient to demonstrate its feasibility. With more than 500 applications of SCR reported by 1997 and growing rapidly, in many different exhaust streams with widely varying degrees of temperature and contaminants, its technical feasibility is not in question. Further, the distinctions between new and retrofit applications involve issues of cost rather than technical feasibility.

The literature cited in the preamble to the December 2000 Chapter 117 rule revisions and many other sources indicate the capability of SCR technology to remove more than 90% of the NO_x from a variety of streams. The removal efficiency is a design criteria, 90% in some new source applications being an inflection point of maximum cost effectiveness in dollars per ton of NO_x removal. In retrofit cases, less than 90% removal with SCR may be the most cost-effective approach because of space or other existing constraints.

Combustion modifications can address SCR constraints, reducing the overall amount of reduction required by SCR, resulting in smaller and fewer SCRs than otherwise would be necessary. The subcategories table in the TABLES AND GRAPHICS section of the January

12, 2001 issue of the *Texas Register* (26 TexReg 706), titled "Subcategories - Point Source Potential NO_x Emission Reductions for Houston/Galveston Nonattainment Area Counties" illustrates the overlap in capability between combustion modifications and SCR to meet the ESADs. In the subcategory of medium process heaters, the Tier I reduction of 49% represents an emission level of 0.060 lb/MMBtu, whereas the Tier II reduction of 90% is equal to the ESAD of 0.010 lb/MMBtu. To achieve the ESAD, the SCR efficiency would need to be 83% on a unit achieving 0.060 lb/MMBtu with combustion modifications, or 67% on a unit achieving 0.030 lb/MMBtu, illustrating the potential for lessened demand on SCR. In the subcategories of smallest heaters and boilers, combustion modifications will be the only technology required. Even in the absence of a cap and trade program, the number of SCRs needed would be less than 100% of the medium and large size units because a few units can achieve the 8 and 12 ppm targets with current combustion technology. The number of SCRs is likely to decrease further because of the continuing advancement of combustion technology.

There are few retrofits operating at the large unit ESAD levels because few other retrofit rules are as stringent. Notably, where the levels are as stringent, such as VCAPCD Rule 59 for utility boilers, the retrofit operating levels are below the ESADs. A logical point of comparison for industrial sources is the Los Angeles retrofit standards set by the SCAQMD. The refinery boiler and heater retrofit limit of 0.030 lb NO_x/MMBtu was adopted in 1988. The gas turbine limit of nine ppm was adopted in 1989. The differences between the SCAQMD standards set in the late 1980s and the 2000 HGA ESADs are significant: the boiler and heater ESADs are set

at 0.030 for small, 0.015 for medium, and 0.010 for large chemical and refinery boilers and heaters, and four ppm for gas turbines. In the time between setting the SCAQMD limits and the ESADs, the NO_x control technologies have advanced and become widely demonstrated, as a result of implementing the SCAQMD standards, similar standards in other California districts, and the NO_x RACT and acid rain requirements of the 1990 FCAA. It is also clear from the numerous technical innovations under development today that NO_x control technology is continuing to improve rapidly. In summary, Tier I, II, and III are well-demonstrated retrofit technologies and have been shown to meet the ESADs on individual units.

Deason testified that some units, regardless of whether they are ExxonMobil's, have already met the ESADs if they are "not combustion-only controlled."

The witness's testimony indicates acknowledgment that compliance with the ESADs has already been demonstrated at some units equipped with Tier II or Tier III controls. The commission agrees that the ESADs are technically feasible.

McAngus testified that no non-utility unit in HGA has been retrofit to meet the ESADs, based on his search of HGA and a review of the references listed in the December 6, 2000 adoption preamble.

As noted earlier in this preamble, the frame of reference for retrofit experience is not limited to the United States. Further, the frame of reference for retrofit experience is not limited to

HGA. Therefore, retrofit of units in HGA is not necessary to demonstrate the technical feasibility of the ESADs. SCR has been successfully demonstrated to achieve a 90% reduction of NO_x from combustion flue gas streams. The application of SCR in non-utility retrofit installations has been limited (mostly to refineries in Southern California, Japan, and a few in Europe), and a variety of factors will affect the practice of SCR retrofits in HGA. Retrofits can be expected to be more difficult than new installations. In many applications when SCR is used to comply with cap-type programs, a 90% SCR reduction will be the technical choice because it is the most cost effective. In retrofit applications, 90% reduction with SCR may have technical disadvantages that make a lesser degree of reduction more attractive. These more attractive choices will be feasible because of the ability of Tier I controls to reduce the SCR requirement below 90% in most cases. Gas-fired boilers, process heaters, and gas turbines on average can do significantly better than 0.10 lb/MMBtu or 0.15 lb/MMBtu with Tier I retrofits, the levels that would require a 90% flue gas clean up to achieve the ESADs of 0.010 and 0.015 lb/MMBtu. The emissions from recently reported Tier I retrofits on gas-fired boilers and process heaters range between 0.01 and 0.04 lb/MMBtu and toward the higher range appear to be widely feasible. With this range of Tier I controls, the corresponding SCR reduction to comply with the most stringent ESAD of 0.010 lb/MMBtu is between 0% and 75%. For gas turbines, Tier I retrofits are capable of between 9 and 15 ppmv (0.033 - 0.050 lb/MMBtu) with DLN for some models, and 25 ppm (0.09 lb/MMBtu) with either DLN or wet injection for almost all of the others. With these maximum Tier I controls, the resulting flue gas cleanup reduction requirement would range between 54% and 83%. Therefore, the average SCR

reduction requirement for gas-fired boilers, process heaters, and gas turbines will need to be significantly less than 90%.

Deason testified that in some cases it may not be possible to retrofit a unit with SCR and, if combustion controls do not achieve the ESAD, the options are to overcontrol elsewhere, reduce the firing rate, or shut the unit down.

Application of retrofit control technology on existing equipment, replacement or consolidation of existing equipment, and shutdown of existing equipment are possible options for reducing NO_x. Another option is for an owner to manage activity levels of equipment and place higher levels of control on high utilization units and less controls on less utilized units. The commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of the existing ESADs. The commission is aware that there undoubtedly will be cases in which an owner or operator evaluates the circumstances of a particular unit and determines, for whatever reason, to pursue an option other than retrofit control technology. The commission has determined that the various controls which can be used to meet the ESADs have a proven performance experience and agrees with BP's comment on the Chapter 117 revisions which were proposed in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) that the 90% reductions are technically feasible. A detailed explanation of how the commission has reached these conclusions is provided in the responses to comments elsewhere in this preamble and in the ANALYSIS OF TESTIMONY

section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524).

Under the mass emissions cap and trade program, the agency will allocate to a source a number of allowances (NO_x emissions in tons) which a source would be allowed to emit during the calendar year. The source is not allowed to exceed this number of allowances granted unless they obtain additional allowances from another facility's surplus allowances. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facilities' surplus allowances to meet emission reduction requirements. The mix of control technologies can be greater because the owner can manage activity levels of equipment and place higher levels of control on high utilization units and less controls on less utilized units. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs.

Deason testified that best available control technology (BACT) reflects the best technology available to achieve the lowest limit possible considering both technical feasibility and economic feasibility. Deason further testified that ExxonMobil recently obtained a permit for a new F20 pyrolysis reactor in HGA, and BACT was set at 0.06 lb/MMBtu, while the ESAD is 0.010 lb/MMBtu. McAngus testified that BACT is only used in permits and not rules. Hamilton testified that part of the rule development for the existing ESADs included a review of BACT in SCAQMD, and that the SCAQMD website includes examples of new refinery heaters units that had been permitted at lower levels than the existing ESADs. Hamilton testified that SCAQMD's BACT standards were based on the demonstration that the level of control represented by their BACT could be achieved in practice.

The commission agrees with Deason that by definition in 30 TAC §116.10(3), BACT gives consideration "to the technical practicability and the economic reasonableness of reducing or eliminating emissions from the facility. Under 30 TAC §116.111(a)(2)(C), concerning General Application, BACT applies statewide to anyone who proposes a new facility or modifies an existing facility that will or might emit contaminants to the air in Texas. The commission also agrees that BACT is only used in new source review (NSR) preconstruction authorization under Chapter 116, Subchapter B, New Source Review Permits, and not Chapter 117. BACT determinations are made on a case-by-case basis.

In addition, permit review for major source construction and major source modification in nonattainment areas requires controls that represent the lowest achievable emission rate (LAER). LAER is defined in 30 TAC §116.12, concerning Nonattainment Review Definitions, to include "(A) the most stringent emission limitation which is contained in the rules and regulations of any approved SIP for a specific class or category of facility, unless the owner or operator of the proposed facility demonstrates that such limitations are not achievable; or (B)

the most stringent emission limitation which is achieved in practice by a specific class or category of facilities, whichever is more stringent," and therefore is generally expected to be more stringent than BACT. There is no allowance for economic analysis in the definition of LAER, and therefore, cost cannot be the basis for determining that any emission limitation is unattainable in a LAER determination. In addition, LAER supersedes BACT review for those facilities or pollutants where these requirements overlap.

TCAA, §382.011, requires the commission to establish the level of quality to be maintained in the state's air and to control the quality of the state's air. The commission is required to "seek to accomplish" this through the control of air contaminants by "practical and economically feasible methods." The level of quality of the state's air is measured by whether the air complies with the NAAQS. According to 42 USC, §7409(b), national primary ambient air quality standards are standards which, in the judgment of the administrator of the EPA, are requisite to protect the public health. The criteria for setting the standard is protection of public health, which includes an allowance for an adequate margin of safety. The existing ESADs were developed in order for HGA to achieve attainment with the ozone NAAQS, which is a health-based standard and not a cost-based standard. As a result, the existing ESADs are technically feasible, albeit stringent, standards which represent maximal point source NO_x controls necessary for HGA to attain the ozone NAAQS. Because the goals of the various requirements are different, as described in this response to the comments, there is no question that in some cases the ESADs are more stringent than BACT or even LAER. For example,

the existing ESADs for large boilers go beyond the commission's current BACT. Currently, the NO_x BACT guidelines, which apply statewide, are set at levels achievable with Tier I, or combustion controls. One notable exception is the guideline for large combined cycle gas turbines, which is based on combustion modifications and flue gas cleanup. NO_x controls, including combustion controls, have rapidly improved in capability recently, and appear to be continuing to do so. Recent permits issued by the commission have set lower NO_x levels than some of the written BACT guidelines which may not reflect current capabilities of Tier I controls.

MODELING

ED commented that this SIP revision and future SIP revisions should not weaken the December 2000 HGA SIP, and that if at any time the commission proposes to remove or modify a strategy in the December 2000 SIP, then it should simultaneously provide a replacement strategy that achieves an equivalent reduction in ozone levels. ED stated that the demonstration of equivalence should be quantitative and based on photochemical modeling. ED further questioned the validity of the qualitative argument presented by the commission about the offsetting benefits of grandfathered pipeline facilities to be adequate, and was particularly concerned that the substituting emission reductions from pipeline facilities will not occur inside the eight-county HGA nonattainment area.

The modeling staff plans to conduct quantitative photochemical modeling early next year of an August/September 2000 episode. This modeling will evaluate the effectiveness of the new requirements for the grandfathered pipeline facilities and determine what, if any, shortfall exists

at that time. If additional measures are required to demonstrate attainment, then the commission will include them in a future SIP revision not later than the 2004 mid-course review.

GHASP commented that the SIP language and the form of the plan to consider the ozone issue and the review of the 90% reduction in industrial point emissions next year is unwarranted and will leave the plan even further behind.

The mid-course review process includes an examination of new information, technology, and science. A thorough evaluation of all modeling, inventory data, and other tools and assumptions used to develop the attainment demonstration has already begun. It will also include the ongoing assessment of new technologies and innovative ideas to incorporate into the plan. For example, if the science supports its development, the commission is committed to developing an enforceable 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, 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. Any revisions to the SIP must ensure that attainment demonstration can be reached.

BCCA and BCCAAG commented that an analysis of ozone monitored data from 1990 to 1998 shows different types of ozone patterns in Houston, with some ozone exceedances reflecting daily gradual increases and decreases in observed ozone values (“typical ozone”). BCCA and BCCAAG stated that other ozone exceedances, however, result from the rapid formation of ozone that exceeds 40 ppb per hour (“spike ozone”). BCCA and BCAAAG stated that spike ozone, which is often responsible for ozone exceedances, has been observed at many monitoring points and under all types of meteorology, and that the 90% reduction in NO_x emissions from point sources (adopted by the commission on December 6, 2000) will not control spike ozone or bring the HGA into attainment. BCCA and BCCAAG stated that spike ozone requires a minimal amount of NO_x and emissions of very reactive compounds. For this reason, BCCA and BCCAAG advocated a two-part attainment strategy, to address two separate causes of ozone exceedances. As the first part of this strategy, BCCA and BCCAAG suggested that the commission use its current photochemical model to design control strategies for exceedances resulting from typical ozone. BCCA and BCCAAG further stated that the commission should then address exceedances resulting from spike ozone by proposing “best management practices” for controlling reactive VOC emissions; completing a scientific assessment and evaluation of key chemical compounds and/or other causes of spike ozone; and adopting rules for controlling reactive VOC emissions.

As part of a court ordered Consent Decree, the commission’s technical analysis staff will provide management with written findings on the following by February 28, 2002: analysis of rapid ozone formation events versus “normal” events; whether these events can be controlled with different strategies; any alternative design value based on “normal” ozone; and any alternate NO_x reductions from point sources, concurrent with substituted emission reduction strategies designed to reduce rapid ozone formation.

Unfortunately, it is difficult to routinely observe the rate at which ozone is formed but instead one can only observe the rate of change in ozone concentration seen at monitoring sites. These two quantities are of course related, but there are important distinctions between them. Furthermore, there are several competing terminologies which are often used interchangeably to describe the various phenomena associated with rapid ozone formation. The agency is attempting to work with scientific experts to propose definitions which help to standardize the discussions of rapid ozone formations and clarify the distinctions between it and ozone "spikes."

A series of accelerated science and technical projects carried out by contract to evaluate the data from the Texas 2000 Air Quality Study (TexAQS), with improved inventories and other information, will provide the commission with the best science to date for making decisions for SIP revisions. In order to propose replacement of the current NO_x ESADs, the commission must reach a sufficient understanding of the cause and effect of ozone formation events and must identify control strategies which are technically sound, sufficiently quantifiable, and readily implementable. Future control strategies may include best management procedures for control of VOC emissions.

ED commented that it is pleased that the commission plans to undertake a scientific evaluation of ozone "spikes" in HGA. ED expressed the belief that reducing emissions of reactive hydrocarbons during upsets and other non-routine emissions events would be an important component of an effective attainment plan for HGA. GHASP applauded the commission for determining that "stakeholders have expressed their belief that the {"ozone spike"} phenomenon is caused by episodic releases of highly reactive VOCs." GHASP stated that some believe that major industrial sources are occasionally releasing major amounts of toxic chemicals into the air (upsets), triggering dramatic increases in ozone smog as well as creating an immediate and direct health risk to the public. GHASP further stated that the relationship between upsets and ozone episodes has been widely known for years, and that the time for the commission to study and propose regulations to address these releases is long overdue. Houston commented that it supports the commission's efforts to determine the impacts of industrial upsets, chlorine, routine non-uniform emissions and the potentially highly reactive nature of NO_x and VOC from point sources in the region so that appropriate policies may be implemented within the next two to three years before the 2004 mid-course review.

The commission's scientific evaluation of ozone "spikes" will seek to address all possible causes of these events to include reactive hydrocarbons during upsets and other non-routine emissions events. Several activities are underway: to further characterize day-to-day levels of VOC emissions in the ship channel area; to compare monitored VOC levels with reported emissions inventories; and to study point source flares and "upsets." These additional data gathering activities should provide better answers for addressing ozone smog in HGA. The Technical Analysis Division staff is on an accelerated timetable to gather as much scientific knowledge on impacts of industrial upsets, chlorine, routine non-uniform emissions, and highly reactive VOC. The commission is using stakeholders from the Houston area as well as

national contractors to work on specific projects so that the best science can be used to implement new policies and/or strategies.

ESAD - UTILITY BOILERS

Reliant supported the revised ESADs for utility boilers in §117.106(c), while Dynegy stated that the revised ESADs in §117.106(c)(1) create an inequity between utility and non-utility boilers. GHASP stated that the commission should clarify that the existing ESADs for utility boilers could be reinstated in 2004 if the commission cannot adopt other regulatory measures to attain the ozone NAAQS in 2007. ED and Sierra-Houston opposed the relaxation of the existing ESADs. ED stated that the commission should apply the reductions from grandfathered pipeline facilities on top of, not instead of, the difference between reductions from the existing and revised utility boiler ESADs. Sierra-Houston stated that the commission should be strengthening standards and not weakening them.

The existing ESADs for both utility and non-utility boilers are technically feasible, as discussed in detail in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register*. The revised ESADs for utility boilers in §117.106(c) were developed by BCCAAG as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described earlier in this preamble. The Consent Order specifically provides that the "Executive Director may propose . . . the Alternate ESAD Selection Rule, which shall consist of either (1) a rule confirming the . . . 80%

Option, or (2) a rule establishing revised ESAD requirements for covered point sources that are different than either the 80% Option" or the ESADs in §117.106(c)(5) and §117.206(c)(1) - (17). Until the scientific assessment is completed in the spring of 2002, it cannot be known if the alternate ESADs will even be implemented and, if implemented, what level of alternate ESADs will be supported by the assessment. If these or other ESADs, or other additional rulemakings, are proposed, the commission will support that proposal with a fiscal analysis and modeling to support any changes to the HGA SIP and the rules in Chapter 117, all of which will be subject to public notice and comment. It should be noted that Dynegy is one of BCCAAG's member companies and presumably had input into BCCAAG's development of the revised ESADs. While there is an inherent inequity in the establishment of a less stringent ESAD for utility boilers at this time, the existing utility boiler ESADs could be reinstated in the future if the commission determines that it is necessary for HGA to attain the ozone NAAQS.

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 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%. The commission believes that the current rulemaking 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.

The commission commits to adopt measures necessary to achieve at least 56 tpd of NO_x emission reductions in the HGA area above and beyond those reductions already identified by the control measures listed in Chapter 6, Table 6.1-2 of the SIP. Additionally, as the commission completes the mid-course review process, as outlined in Section 7.2 of the SIP, it may show that the HGA area needs more or fewer tpd of NO_x emission reductions for attainment by November 15, 2007. Should the scientific assessment and mid-course review show that more or fewer reductions are necessary, the commission will submit the revised reduction calculation to EPA for approval. The SIP revision submitted in May 2004 will

account for those additional reductions above and beyond the 56 tpd commitment if the mid-course review shows they are necessary for attainment.

In any case, the 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 results 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.

EPA commented that the commission should document for the record that relaxing controls for utility boilers from 93.5% to 90% still represents reasonably available control measures (RACM) for these sources. EPA also commented that if the commission develops additional proposed rulemaking and an additional revision to the SIP to implement alternative NO_x ESADs for point sources, the commission will have to demonstrate, as part of that SIP revision, that the new level of control is still RACM for point sources. Finally, EPA commented that the commission should document that a RACM level of control is being instituted for glass manufacturing plants since the one significant source in the inventory has now been issued a permit requiring oxygen firing.

The commission agrees with the comments regarding RACM for utility boilers and for glass manufacturing plants. Language has been added to Section 7.3 of the SIP to address these comments. Regarding any additional future rulemaking, the commission will take this comment into account if such a rulemaking does occur.

McAngus testified concerning four California utility boilers owned by Reliant. McAngus acknowledged that these units are meeting the ESADs, but suggested that inherent differences between these units and the utility boilers in HGA will make the ESAD technically infeasible to achieve. McAngus stated that a fundamental difference is that the Reliant California units are capable of firing fuel oil and natural gas while the HGA units were originally designed to fire exclusively natural gas. McAngus stated that gas-fired boilers tend to be more compact than boilers designed to burn fuel oil, and therefore are more limited in possible retrofits. Hamilton testified that the existing gas utility boiler ESADs are approximately equal to the VCAPCD retrofit standards.

The commission disagrees with McAngus's claim that the emission standard of 0.010 lb NO_x/MMBtu is technically infeasible for gas-fired utility boilers. In combination, combustion modification and SCR are technically capable of achieving these levels on any gas-fired utility boiler. This level of control may be economically infeasible for particular gas-fired utility boilers, but this is a function of the availability of lower cost competing electric generation technology, such as highly efficient combined cycle turbine power plants and the choices made by the operators. Regardless, because rule compliance is based on a flexible cap, it will not be necessary for each gas-fired boiler to achieve the ESAD. It is true that the gas utility boiler ESAD is more stringent than most of the actual emission rates of the boilers in Southern California. Most of the Southern California boilers are operating under the SCAQMD cap and trade program, Regional Clean Air Incentives Market (RECLAIM), for which the underlying emission specification is the 1991 SCAQMD Rule 1135 emission standard of 0.15 pound NO_x per megawatt-hour (lb NO_x/MWh). This output standard is approximately equal to a heat input

standard of 0.015 lb/MMBtu. In Reliant's comments on the Chapter 117 revisions which were proposed in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275), Reliant stated that only four of 13 boilers they identified in Southern California are below the ESAD and that the average emission rate of the 13 boilers is 0.015 lb NO_x/MMBtu. Four of the 13 boilers Reliant identified, Ormond Beach 1 and 2, and Mandalay 1 and 2, are the only utility power boilers subject to the VCAPCD retrofit emission limit of 0.10 lb/MWh, essentially equal to the 0.010 lb NO_x/MMBtu ESAD. These four boilers are now owned by Reliant. The data Reliant supplied in their previous comments indicate that the MW weighted average emission rate for these four boilers is 0.0085 lb/MMBtu, which is comfortably below the existing ESAD. Three of these boilers are among the four which operate below the existing ESAD. The average performance level is clearly a function of compliance with the regulatory standard. The technical feasibility of the gas utility boiler ESAD is supported by the fact that a number of the Southern California boilers are operating below the existing ESAD. Just as more of the Southern California boilers are operating above the Rule 1135 specification under RECLAIM, the smaller and less frequently operated boilers in HGA will be able to continue to operate above the ESAD under cap and trade compliance.

The smaller furnace volumes of some of the Reliant gas boilers may make them relatively more difficult to control than some of the California boilers with somewhat larger furnace volumes. This would only mean that with identical controls, the Reliant boilers would produce somewhat higher levels of NO_x. This would not mean that achieving the ESAD is technically infeasible,

although the smaller furnace volumes would have some relevance in the cost. Combustion NO_x technology has improved markedly in the years since the Southern California boilers were retrofit. There are new approaches, such as premix of fuel and flue gas to produce a low-NO_x fuel. Under demonstration on a utility unit in Collin County, Texas, this is currently achieving 0.04 lb/MMBtu, with expectations of even better performance. The accumulation of recent experience makes it evident that even the most difficult gas-fired utility boiler in HGA can be controlled to at least a level of 0.10 lb/MMBtu with combustion controls. It is also clear from the Southern California gas utility boiler SCR experience that SCR is technically feasible of achieving more than a 90% reduction on a gas utility boiler. The average performance of the Southern California utility boilers reported in Table 2-5 of *Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers* (June 1998), prepared for Northeast States for Coordinated Air Use Management and Mid-Atlantic Regional Air Management Association (will be referred to as NESCAUM) is 89.6%, the highest, 94%, using in-duct SCRs. Stand-alone SCR reactors may be designed with higher catalyst volumes and higher control efficiency. With all of the combustion technology currently available, gas-fired utility boilers can be modified to achieve quite a bit less than 0.10 lb/MMBtu. A 90% reduction with SCR from 0.10 lb/MMBtu will achieve the existing ESAD of 0.010 lb/MMBtu. Therefore, the combination of combustion control and SCR is technically capable of achieving the existing gas utility boiler ESAD.

McAngus stated that certain types of low-NO_x burners can not be used because the flame will sometimes impinge on the tubes, resulting in hot spots which will cause the tubes to fail prematurely.

McAngus did not specify exactly which types of low-NO_x burners to which he referred. Even if McAngus's claims were accurate, his testimony indicates his opinion is that the alleged problem occurs only with certain types of burners, such that other low-NO_x burners are available for which flame impingement is not an issue.

Burner manufacturers design burners for specific combustion properties, including flame shape. In each case, application engineers are responsible to select the best burner for the chamber and process. Selecting a burner that will provide a flame geometry that is suitable for the application is a vitally important part of engineering a thermal system. As units are refitted with new low-NO_x combustion hardware, the flame geometry will be different from conventional burners. However, one of the tasks of combustion equipment vendors is assisting the end user in selecting hardware that is compatible with the geometry and heat requirements of the unit.

A low-NO_x burner manufacturer's experience is that if no change is made to the fuel being fired during a burner retrofit, then a low-NO_x burner can be engineered to conform with the physical constraints of the unit. Some geometries are particularly challenging and the burner configuration may need to be modified in ways that will increase the NO_x emissions in the low-

NO_x burner, above the low NO_x emissions that would be developed by that same burner under the same firing conditions, in a "friendlier" chamber.

However, control options other than low-NO_x burners are also available, and combustion controls continue to develop dynamically, achieving teen and even single digit NO_x ppm in a growing number of applications. Burner replacement is but one of many combustion control options. For example, an external gas conditioning system can be added which introduces inert gas using existing fuel pressure (i.e., without moving parts) into an eductor where it dilutes the fuel to produce a low-NO_x fuel. The inert gas reduces peak flame temperatures, lowers available O_2 concentration, and minimizes reaction times, thereby reducing both prompt NO_x and thermal NO_x formation. Under demonstration on a utility boiler in Collin County, Texas, this is currently achieving 0.04 lb/MMBtu, with expectations of even better performance.

ESAD - FCCU

Deason testified that no FCCU with an SCR retrofit has achieved the ESAD. Hamilton testified that the 90% reduction of the FCCU ESAD is based upon the ExxonMobil FCCU in Torrance, California. Hamilton testified further that if this FCCU was in fact a new unit rather than a retrofit, it would be useful as an example of a unit that is "actually in operation achieving levels lower than the adopted emission standard," and therefore, still would be significant. Hamilton testified that the difference between retrofits and new units is "significant in terms of cost, but not in terms of technical feasibility."

The commission agrees with Hamilton and notes that SCR is in commercial operation on FCCUs on a significant number of units worldwide, including the United States, Japan and Europe (at least seven in Japan, one in the Netherlands, and ExxonMobil in Torrance, California). The ExxonMobil Torrance refinery SCR was designed for a 90% removal. On August 14, 2001, a SCAQMD representative stated that SCAQMD hasn't had any new FCCU installations with SCRs and that the ExxonMobil Torrance refinery FCCU was definitely an SCR retrofit to an existing FCCU.

For the FCCUs which use wet scrubbers, low-temperature or phosphatic oxidation may be a viable technology alternative to SCR which would utilize the existing scrubber and avoid moving major equipment or reheating flue gas to achieve the necessary temperature window for SCR. The combination of demonstrated removal efficiencies from both Tier I and Tier II controls and the option in the existing FCCU ESAD of either a concentration limit or a percent reduction ensures that this standard is technically feasible.

ESAD - BIF UNITS

TCC stated that the ESAD for BIF units may be unachievable for BIF units that burn wastes containing fuel-bound nitrogen.

Today's understanding of NO_x formation includes three different mechanisms for generation of NO_x. Thermal NO_x is formed by the oxidation of atmospheric nitrogen present in the

combustion air. Prompt NO_x is produced by high speed reactions at the flame front. Fuel NO_x is formed by the oxidation of nitrogen contained in the fuel. Prompt NO_x is more likely to form in a fuel-rich environment because of its dependence on hydrocarbon fragments. This is very different than thermal NO_x, which is highly dependent upon air concentrations.

Chemically-bound nitrogen, also called fuel-bound nitrogen, is one of the three common production routes for NO_x emissions. These emissions were presumably reflected in the emission factors that the BIF and incinerator owners provided to the commission in the emission rate survey conducted in the first quarter of 2000. The existing ESADs for BIF units in §117.206(c)(3) were developed from this information and therefore reflect the effects of fuel-bound nitrogen. NO_x produced by fuel-bound nitrogen is not any different from NO_x formed by the other formation mechanisms, "thermal" or "prompt" NO_x. Because of this, the presence of fuel-bound nitrogen does not pose questions of technical feasibility that have not already been considered.

TCC also stated that many wastes burned in BIF units contain components that cause catalyst fouling and poisoning, resulting in poor performance and higher operating costs, and may counter other technologies driving organic and/or dioxin destruction and metal removal. TCC suggested that the ESAD be relaxed to a level representing non-SCR technology.

The existing ESAD for BIF units in §117.206(c)(3) is not based upon combustion modifications due to the potential for affecting the hydrocarbon destruction and removal efficiencies, but instead is based upon Tier 2 control. Because the largest BIFs, those rated above 100 MMBtu/hr heat input, are industrial boilers burning liquid hydrocarbon wastes without high levels of inorganic "dirty" materials and without wet scrubbers, the use of SCR would not be a problem for the largest BIF boilers because hydrocarbon wastes combusted in these boilers produce exhaust products essentially indistinguishable from any hydrocarbon fuel. Therefore, the existing ESAD in §117.206(c)(3)(A) for BIFs rated 100 MMBtu/hr heat input or greater is based on SCR at 90% control because these boilers combust hydrocarbon wastes which do not threaten to reduce the effectiveness of SCR as the flue gas cleanup application.

For smaller BIFs, the existing ESAD in §117.206(c)(3)(B) is based on 80% control, rather than 90%, to take into account the concerns raised that certain of the units have "dirty" exhaust streams, primarily with sulfur and chlorides, and a few with some metals and other inorganics. Liquid firing is almost a prerequisite for classification as a BIF, because gaseous materials are not regulated as hazardous waste under Resource Conservation and Recovery Act (RCRA) regulations. The units with "dirty" exhaust streams use wet scrubbers to remove acid gases and some of the other inorganics. Considering the "dirty" streams, SCR has been employed in a few high sulfur fuel oil applications, but the inorganic compounds present in the exhaust degrade the performance more rapidly than cleaner fuels.

In addition to SCR, there are two new oxidation technologies for NO_x reduction which are not yet fully demonstrated. One technology has some demonstration in commercial practice, and the other appears to be moving rapidly to commercial demonstration. One of these, low-temperature oxidation, injects ozone as the oxidant to form dinitrogen pentoxide (N_2O_5), which is then removed in a wet scrubber. Because N_2O_5 is highly soluble in water, this process produced NO_x removal efficiencies in the 99% range (i.e., achieved reductions to two ppm NO_x) when demonstrated commercially on a natural gas-fired boiler in Los Angeles which began operation in October 1996. The other process injects elemental phosphorus as the oxidant to form nitrogen dioxide (NO_2), which is also removed in a wet scrubber. The phosphorus based process is anticipated to produce at least 75% reduction in a commercial demonstration on a high sulfur coal-fired utility boiler in Ohio, scheduled for startup in the second half of 2001. The boiler retrofit project is under the financial sponsorship of the owner, a large electric utility.

The commission believes that the exhaust streams from the BIFs with higher levels of inorganics will pose greater technical challenges than the more common, cleaner streams. SCR removal efficiency of 80% would be a more reasonable design goal for "dirty" fuel streams. The BIF units with existing scrubbers would logically be good candidates for NO_x scrubber technology because of the potential avoidance of capital expenditure for a new scrubber as well as the operational experience in place with the scrubbers. The oxidation technologies appear capable of the 90% reductions envisioned by the proposed BIF ESAD. However, developing technologies, like NO_x oxidation, are likely to have more unforeseen practical challenges

compared to established technologies and these challenges can compromise performance goals. Because of the concerns raised by the commenters about inorganic materials in the exhaust streams, the existing ESAD for the BIFs rated less than 100 MMBtu/hr heat input is either an 80% reduction from baseline, or 0.030 lb/MMBtu.

ESAD - WOOD-FIRED BOILERS

Abitibi commented on the NO_x emission specification of 0.046 lb/MMBtu for wood-fired boilers in §117.206(c)(5) and the proposed §117.206(c)(18)(E). Abitibi stated that one of its boilers, which the commission has classified as a wood-fired boiler, is a "combination-fuel boiler" which fires a variety of fuels, including wood, tire-derived fuel (TDF), and dewatered wastewater treatment sludge. Abitibi stated that the higher percentage of nitrogen-containing compounds in sludge as compared to wood can be expected to increase NO_x emissions in boilers using wood in combination with other fuels, as compared to wood-fired boilers. Abitibi also stated that TDF is necessary to provide the necessary heat input to offset the relatively high moisture content of the sludge.

As noted earlier in this preamble, chemically-bound nitrogen, also called fuel-bound nitrogen, is one of the three common production routes for NO_x emissions, the others being thermal NO_x and prompt NO_x. Emissions from fuel-bound nitrogen and emissions associated with offsetting the relatively high moisture content of the sludge were presumably reflected in the emission factors that Abitibi (or its predecessor company, Donohue Industries Incorporated (Donohue)) provided to the commission in the emission rate survey conducted in the first quarter of 2000. The existing ESAD for wood-fired boilers in §117.206(c)(5) was developed from this

information and therefore reflect the effects of fuel-bound nitrogen and the moisture content of the sludge. NO_x produced by fuel-bound nitrogen is not any different from NO_x formed by the other formation mechanisms, "thermal" or "prompt" NO_x. Because of this, the presence of fuel-bound nitrogen does not pose questions of technical feasibility that have not already been considered. Similarly, NO_x resulting from additional heat input due to the moisture content of the sludge is no different than other NO_x and does not pose questions of technical feasibility that have not already been considered.

Abitibi stated that there are significant technical issues associated with the use of SCR on boilers using wood in combination with other fuels, and that it may take several years for proven technologies to be available that can achieve an 80% NO_x reduction. Abitibi stated further that the use of SNCR on combination-fuel boilers can only achieve a 55% NO_x reduction, and requested that the commission establish an SNCR-based ESAD for either combination-fuel boilers or for all wood-fired boilers. Abitibi stated that the current ESAD in §117.206(c)(5) should be revised, and that at the very least the alternate ESAD of §117.206(c)(18)(E) should be revised.

The commission agrees that multi-fueled industrial boilers can add some difficulty to the control of NO_x. However, there is enough theoretical and practical experience with SNCR in mixed fuel systems to demonstrate the technical feasibility of SNCR. The science of computer modeling, and the improvement of injection, control, and sensor systems have made this possible. SNCR normally operates with real time control of reagent feed versus load, and follows swings quite closely. Proper use of these inputs also minimizes the formation of

ammonia-related problems in the combustion system, cold end, and stack emissions. The commission is aware of a mixed fuel industrial boiler (based on wood waste, biomass sludge, etc.) at Bowater Newsprint's pulp and paper mill in Calhoun, Tennessee that is achieving a 62% NO_x reduction with urea-based SNCR. There have been no particular problems reported with the operation of Bowater's SNCR system since it was installed. The commission is aware of at least 16 other commercial applications of urea-based SNCR on wood- or wood/biomass-fired systems on boilers ranging in size from 130 to 550 MMBtu/hr, representing NO_x reductions of 35% - 60% (average of 51%). In some cases, the data for these individual units represent the guaranteed reduction percentages or the permitted limits, both of which are set to provide a "cushion" such that the actual emission reductions are greater than the targeted emission reductions. In other words, lower efficiencies may simply reflect the regulatory limit rather than the capability of the technology in the particular application.

SNCR is not adversely affected by inorganics in the exhaust because there is no catalyst to degrade, and the NO_x reductions are favored in the high-temperature zone where SNCR is located. However, SNCR is typically capable of reductions in the 50% - 60% range, not high enough to achieve the ESAD, although one option would be to install SNCR and use credits, which are available to the owners of the wood-fired boilers, to satisfy the remainder of the reductions.

Although the use of SCR may be technically challenging due to "dirty" exhaust streams, SCR catalyst formulations are adjustable to reduce sensitivities to various catalyst poisons. SCR has been employed in boilers firing high sulfur fuel oil (up to 5.4% sulfur) and on cement kilns in commercial demonstrations in Sweden and Germany. The inorganic compounds and particulate matter present in the exhaust streams of these applications degrade the performance more rapidly than cleaner fuels, thereby shortening the life of the catalysts. Although catalyst replacement cost may be higher relative to a conventional SCR, SCR is still technically feasible. SCR has been operating on a 57 MMBtu/hr wood-fired boiler at Sauder Woodworking in Ohio since 1994, meeting its NO_x reduction objectives during that time.

In addition to SCR, there are two new oxidation technologies for NO_x reduction which are not yet fully demonstrated. One technology has some demonstration in commercial practice, and the other appears to be moving rapidly to commercial demonstration. One of these, low-temperature oxidation, injects ozone as the oxidant to form N_2O_5, which is then removed in a wet scrubber. Because N_2O_5 is highly soluble in water, this process produced NO_x removal efficiencies in the 99% range (i.e., achieved reductions to two ppm NO_x) when demonstrated commercially on a natural gas-fired boiler in Los Angeles which began operation in October 1996. The other process injects elemental phosphorus as the oxidant to form NO_2, which is also removed in a wet scrubber. The phosphorus based process is anticipated to produce at least 75% reduction in a commercial demonstration on a high sulfur coal-fired utility boiler in

Ohio, scheduled for startup in the second half of 2001. The boiler retrofit project is under the financial sponsorship of the owner, a large electric utility.

SCR removal efficiency of 80% would be a more representative design goal for dirty fuel streams. The oxidation technologies appear capable of the 90% reductions envisioned by the ESAD proposed in August 2000. However, developing technologies, like NO_x oxidation, are likely to have more unforeseen practical challenges compared to established technologies and these challenges can compromise performance goals. Because it would appear equitable to revise the alternate ESAD for wood-fired boilers in §117.206(c)(18)(E) in the event that the alternate ESADs are implemented, the commission has modified the alternate ESAD for wood-fired boilers to 0.060 lb/MMBtu. This represents SNCR achieving a 60% NO_x reduction. If implemented, this alternate ESAD would result in 0.07 tpd fewer emission reductions than the current ESAD.

ESAD - OIL-FIRED OR LIQUID-FIRED BOILERS

No changes were proposed to the ESAD for oil-fired boilers in §117.206(c)(7). However, the commission clarifies its intent that this ESAD applies not just to boilers firing oil, but to boilers firing any liquid fuel which does not cause the unit to fall under the BIF unit ESAD. The commission anticipates initiating rulemaking after October 15, 2001 to revise §117.206(c)(7) accordingly, along with a variety of other minor clarifications that were not included in the current rulemaking.

ESAD - ICI BOILERS AND PROCESS HEATERS

Deason testified that no process heater with an SCR retrofit has achieved the ESAD. Deason testified that all retrofits that ExxonMobil identified, whether in Louisiana, California, or Germany, are "performing at levels well in excess of" the ESADs. Hamilton testified that the 0.036 lb/MMBtu ESAD for process heaters and furnaces less than 40 MMBtu/hr in size is less stringent than the 0.030 lb/MMBtu retrofit standard set by numerous districts in California for that type of equipment.

The commission disagrees with Deason. There are many ICI boilers and process heaters in a wide range of sizes, retrofit with no more than combustion modification controls, operating below the 0.036 lb/MMBtu ESAD (30 ppmv) for boilers and heaters less than 40 MMBtu/hr in size. Most districts in California set boiler and process heater retrofit requirements at this level for ICI boilers and process heaters above five MMBtu/hr, whereas SCAQMD and VCAPCD set the applicability levels at two MMBtu/hr and higher. The 30 ppmv NO_x limit has proved to be met by combustion modifications only.

There are fewer ICI boilers and process heaters above 40 MMBtu/hr in size which are operating at the 0.010 and 0.015 lb/MMBtu ESADs (8 and 12 ppmv, respectively) for equipment larger than 40 MMBtu/hr. This is because the most stringent NO_x retrofit standards anywhere, set under the RECLAIM program in the SCAQMD in 1993, are based on the 1988 SCAQMD Rule 1109 limit of 0.030 lb NO_x/MMBtu for refinery heaters and boilers. At the Los Angeles refineries, Rule 1109 and RECLAIM have resulted in relatively fewer of

the larger sizes of ICI boilers and process heaters controlled to levels near the HGA specifications, with a greater number of smaller or less frequently operated units controlled to less stringent specifications. Nonetheless, at least nine refinery heaters between 60 and 931 MMBtu/hr have been retrofitted and are currently achieving emissions ranging from 0.004 to 0.011 lb/MMBtu, with a heat input weighted average emission rate of 0.006 lb/MMBtu. The average rate is substantially below the ESADs of 0.010 and 0.015 lb/MMBtu.

The RECLAIM program uses a declining cap which only in 2000 caused emission credits to become tight and valuable; the allocations will be reduced at least two more years, so additional reductions are necessary. The largest refinery boilers in HGA overlap in size with the smallest utility boilers. The following utility boilers in Southern California are operating below the 0.010 ESAD using Tier III controls: El Segundo 4, 0.008 lb/MMBtu; Mandalay 1 and 2; 0.007 lb/MMBtu; Ormond Beach 2, 0.007 lb/MMBtu. The 320 MW El Segundo 4 is achieving levels significantly below the Rule 1135 regulatory driver of 0.015 lb NO_x/MMBtu in Southern California because the emission trading program rewards overcompliance. Another unit, the 110 MW Encina 2, is operating at 0.014 lb NO_x/MMBtu.

The annual NO_x emission rate data for these and other utility boilers operating in Southern California with Tier III controls can be found by inspecting the EPA acid rain data base at http://www.epa.gov/acidrain/score98/es1998.htm.

The present relative scarcity of retrofit applications operating near the existing HGA ESADs is a function of regulatory standards, rather than technical feasibility. Regulations set emission levels, and the HGA NO_x ESADs are lower than the Los Angeles standards in several categories. The rules underlying Los Angeles' current point source NO_x retrofit specifications were adopted more than ten years ago and until now, only a few areas, such as VCAPCD, have set lower retrofit specifications. The progressive development and application of technology in Los Angeles and elsewhere in the world to existing and new equipment, achieving single digit NO_x ppm, demonstrates that the Houston NO_x emission specifications are technically feasible.

McAngus testified that regarding the nine California process heaters cited by the commission as meeting the ESADs (three at Chevron (El Cerrito) and six at Mobil (Torrance)), "we contacted each of these facilities and talked to them....” and “all three of {the Chevron} furnaces were new facilities that had been built in the early ‘90s” and “the SCRs had been designed into the original design of this process, so it was not a retrofit condition.” McAngus further testified that “in the situation for Mobil, there were six furnaces,” and “five of the six” were new facilities. “In the case of the retrofit, it had an ammonia slip limit of about 20 ppm, which is twice the” Chapter 117 limit of ten ppm. McAngus suggested that information from SCAQMD in response to a November 27, 2000 email, which provided the basis for the reference, was not accurate because the units referenced that are meeting the ESADs are new, not retrofits, and therefore the ability "to retrofit down to these levels {i.e., the ESADs} has not been demonstrated." Hamilton testified that if these process heaters were in fact new units rather than retrofits, they would be useful as examples of units that are "actually in operation achieving levels lower than the adopted emission standard," and therefore, still would be significant. Hamilton testified that the difference between retrofits and new units is "significant in terms of cost, but not in terms of technical feasibility."

The commission disagrees with McAngus's claim that the ability to retrofit to meet the existing ESADs has not been demonstrated. McAngus's own testimony is that at least one of the six process heaters meeting the ESADs at ExxonMobil in Torrance is a retrofit. The commission agrees that retrofits can be expected to be more difficult than new installations. However, as described elsewhere in this preamble, including the response to the previous comment, as well as in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)), the existing ESADs are technically feasible. The difference between retrofits and new installations relates more to potential cost and the need for a reasonable compliance schedule to implement the retrofits than to the technical feasibility of the ESADs. As noted in the response to the previous comment, at least nine refinery heaters between 60 and 931 MMBtu/hr have been retrofitted and are currently achieving emissions ranging from 0.004 to 0.011 lb/MMBtu, with a heat input weighted average emission rate of 0.006 lb/MMBtu. The average rate is substantially below the ESADs of 0.010 and 0.015 lb/MMBtu. On August 15, 2001, a SCAQMD representative confirmed McAngus's testimony that one of the six process heaters meeting the ESADs at the ExxonMobil refinery in Torrance is a retrofit. Specifically, the SCAQMD representative advised that heater 924 at this ExxonMobil refinery was retrofitted with an SCR unit in 1992. On August 15, 2001, the SCAQMD representative also confirmed that the three process

heaters meeting the ESADs at the Chevron refinery in El Cerrito were retrofitted with a common SCR unit in 1994. The commission agrees with Hamilton that the five process heaters which were new units rather than retrofits are useful as examples of units that are in operation achieving emission levels below the existing ESAD.

Deason testified that a new ethylene plant pyrolysis reactor was built in Germany in the late 1980's and was designed with a low-temperature SCR when built. Deason testified that it was designed "to achieve a standard five times the level" of the applicable ESAD, and the SCR requires annual maintenance to clean particulate off the catalyst.

Ethylene furnaces present a challenge to control, particularly with regard to Tier I controls, due to a variety of factors. Ultra low-NO_x burners on recently constructed ethylene furnaces, including ones in HGA, are capable of 0.050 - 0.060 lb/MMBtu, which is considerably higher than what is achievable on boilers and process heaters in less strenuous applications. Nonetheless, based on permitting experience and discussions with burner vendors, the commission believes that combustion modifications are capable of achieving at least 0.10 lb/MMBtu on the existing ethylene furnaces in HGA. The existing ESAD of 0.010 lb/MMBtu places a demand on burners and combustion modification to achieve at least 0.10 lb/MMBtu; SCR is capable of at least 90% reduction below this. The recently permitted furnaces in HGA achieve significantly better than 0.10 lb/MMBtu with combustion modifications, allowing either a less efficient SCR, or more likely, overcompliance for generation of emission credits. The

commission is aware of low-temperature SCR on ethylene furnaces in Germany and the Netherlands; the installation in the Netherlands is a retrofit application achieving a 91% NO_x reduction. Low-temperature SCR, which is installed at the back end of the furnace, may be an attractive option for many of these units because of the clean fuels burned and the complexity of the heat recovery sections.

Regarding the German ethylene furnace that Deason referenced, Deason did not indicate what emission specification this unit was designed to achieve. If the unit was specifically designed to meet a less stringent requirement, it would not be logical to expect that the unit would necessarily meet a more stringent ESAD. Depending on the regulations in effect and the compliance strategy used by the owner, lower control efficiencies may simply reflect design for compliance with the regulatory limit rather than the capability of the technology in the particular application. The NO_x reduction obtainable with SCR is a design parameter, and it can be expected that a number of retrofits will be designed for at least 90% reduction in HGA.

Deason also did not provide details about the reported annual maintenance on the German unit's SCR. It is possible that coke formed during the pyrolysis reaction in an ethylene furnace could degrade the low-temperature SCR catalyst performance more rapidly than other applications, thereby shortening the life of the catalyst and/or resulting in periodic maintenance to clean particulate off the catalyst. Although these maintenance activities would result in

higher operating costs relative to a more conventional SCR application, SCR is still technically feasible.

ESAD - IC ENGINES

GHASP supported the new ESADs for diesel engines. ED stated that future emissions from stationary diesel engines used for electrical generation in HGA could be significant and undermine the SIP. ED suggested that the same requirements as the Air Quality Standard Permit for Electric Generating Units, effective June 1, 2001, should be established for new and existing stationary diesel engines in HGA that are not used exclusively for emergency situations.

Amendments to Chapter 106, Permits by Rule, Subchapter W, Turbines and Engines, effective June 1, 2001, preclude registration under §106.512 of new or modified engines or turbines used to generate electricity. However, exempted from this preclusion are: 1) engines or turbines used to provide power for the operation of facilities registered under the Air Quality Standard Permit for Concrete Batch Plants; 2) engines or turbines satisfying the conditions for facilities permitted by rule under Chapter 106, Subchapter E, Aggregate and Pavement; and 3) engines or turbines used exclusively to provide power to electric pumps used for irrigating crops. While it is possible that an owner or operator of a new or modified engine or turbine used to generate electricity could pursue preconstruction authorization under Chapter 116, Subchapter B, New Source Review Permits, the commission expects that most, if not all, such owners or operators would pursue authorization under the Air Quality Standard Permit for

Electric Generating Units, effective June 1, 2001, in order to expedite the permit authorization process and minimize costs associated with public notice. In addition, the commission expects that the BACT review resulting from an owner or operator seeking preconstruction authorization under Chapter 116, Subchapter B, New Source Review Permits, for a new or modified engine or turbine used to generate electricity would result in the same level of control as the standard permit. Further, an existing 100 hp engine emitting NO_x at an uncontrolled rate of 11.0 g/hp-hr would have a design capacity to emit greater than ten tpy of NO_x, and consequently would be subject to the Chapter 101 mass emissions cap and trade program. It should be noted that a new engine which operates 100 hours per year or more in nonemergency situations would not receive allocations and would have to obtain credits in order to operate, thereby protecting against an increase in emissions in HGA and maintaining the integrity of the SIP.

Based upon information in the commission's emissions inventory and contact with diesel engine vendors and others familiar with the stationary diesel engines in HGA, the commission is unaware of any existing stationary diesel engines that are being operated in situations other than generation of electricity in emergency situations or operation for maintenance and testing. Since any such existing engines at a site with a collective design capacity to emit (from units with ESADs) equal to or greater than ten tpy of NO_x are subject to the Chapter 101 mass emissions cap and trade program if they operate 100 hours per year or more (based on a rolling 12-month average) and will be issued allocations based on their historical activity level, the

commission does not believe that these engines currently merit additional emission limitations beyond those in this rulemaking. It is possible that existing emergency diesel generators could be converted to peak shaving use, thereby contributing to ozone exceedances due to operation on days which tend to have favorable conditions for high ozone levels. However, emergency diesel generators typically are on a timer which operates them for 30 minutes to one hour per week for maintenance and testing. Since the 100 hours per year limit includes the time of operation for maintenance and testing, this would leave approximately 48 to 74 hours per year available for peak shaving operation. This is expected to be too few hours of peak shaving to justify the expense of the interconnect switching equipment necessary to supply power to the grid. The commission believes that these factors will effectively discourage the conversion of existing emergency

generators to peak shaving units while still reducing emissions in a cost-effective manner when the engines are replaced, modified, reconstructed, or relocated. Therefore, the commission made no change in response to the comments.

ESAD - GAS TURBINES

Deason testified that no gas turbine or duct burner, whether new or retrofit, has achieved the ESAD of 0.015 lb NO_x per MMBtu, based on “an extensive survey” conducted by industry representatives in 2000.

The existing HGA retrofit standards for gas turbines appear to be the most stringent retrofit standards in the world. Because of this, very few retrofits have been designed to meet these

levels. The existing ESAD is below the levels in SCAQMD Rule 1134 because it is technically feasible to meet a more stringent standard. Specifically, the commission is aware of several units which are operating below the existing ESAD. The 32 MW gas turbine at the Federal Plant in Vernon, California has been retrofitted with a NO_x adsorber catalyst to achieve emissions of two ppm NO_x, which is 50% lower than the existing gas turbine ESAD. Other gas turbines have included the Tier III combination of combustion modifications and SCR controls in the original design and are operating below the existing ESAD. An example is the 102 MW combined cycle Siemens V84.2 gas turbine at the Sacramento Power (Campbell Soup) plant in Sacramento County, California. This gas turbine includes a duct burner rated at 200 MMBtu/hr and has been operating at three ppmv NO_x since October 1997. In addition, since July 1999, the commission has received permit applications for at least 25 new gas turbines, in projects representing more than 6,800 MW of new electric capacity, all to be located in HGA and to operate below the 0.015 lb/MMBtu ESAD for gas turbines, using Tier III controls.

The commission took into account the capabilities of the various technologies when setting the ESAD for turbines. Tier I combustion modifications have been applied to most of the gas turbines above ten MW in HGA because of the 42 ppmv, 15% oxygen (0.15 lb/MMBtu) NO_x RACT limit of §117.205. The Tier I technologies, DLN and steam or water injection have been used to meet this limit. For units just meeting the RACT limit, Tier II flue gas cleanup would require a 90% additional reduction. Tier I retrofits are capable of between 9 and 15 ppmv (0.033 - 0.050 lb/MMBtu) with DLN for some models, and 25 ppm (0.09 lb/MMBtu) with either

DLN or wet injection for almost all of the others. With these maximum Tier I controls, the resulting flue gas cleanup reduction requirement would range between 54% and 83%. The BCCA surveyed a number of firms involved with gas turbine SCR projects and their summary indicated that among hundreds of gas turbine SCR applications, there were about one dozen retrofits. In many applications when SCR is used to comply with cap-type programs, a 90% SCR reduction is the technical choice because it is the most cost effective. In retrofit applications, 90% reduction with SCR may have technical disadvantages that make a lesser degree of reduction more attractive. These more attractive choices will be feasible because of the ability of Tier I controls to reduce the SCR requirement below 90% in most cases. The summary did not indicate levels of reduction for these SCR retrofits but, due to the cost of installing SCR, it would be expected that few would have been designed for less than 70%. However, depending on the regulations in effect and the compliance strategy used by the owner, lower efficiencies may simply reflect design for compliance with the regulatory limit rather than the capability of the technology in the particular application. The NO_x reduction obtainable with SCR is a design parameter, and it can be expected that a number of retrofits will be designed for at least 90% reduction in HGA.

Regarding duct burners, a gas turbine equipped with a duct burner is not expected to be more difficult to retrofit with controls than a gas turbine without a duct burner. Gas turbines with and without duct burners have effectively been placed in the same category for purposes of the ESADs based on data collected by the Air Permits Division as part of a March 2000 review of

BACT for gas turbines. It should be noted that it would be more cost-effective to control a gas turbine/duct burner combination because the additional NO_x from the duct burner could be controlled with the same SCR unit, such that there would be no additional capital expense for a separate SCR.

ESAD - INCINERATORS

Safety-Kleen commented on the existing and proposed alternate ESADs for incinerators in §117.206(c)(16) and (18), which establish an ESAD of either 0.030 lb NO_x per MMBtu, or an 80% reduction from the emission factor used to calculate the June - August 1997 daily NO_x emissions. Safety-Kleen noted that for the 80% option, new language specifies that a consistent methodology must be used to calculate the 80% reduction.

The new language 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.

Safety-Kleen stated that according to its emission calculations and documentation in its recently submitted level of activity certification, the expected reduction in actual emissions for its two commercial hazardous waste incinerators will be greater than 91%, because Safety-Kleen's level of activity for the June - August 1997 time period was "unusually low" and may vary significantly as a result of processing a wide variety of waste streams. Safety-Kleen noted that proposed changes to §117.108(c)(1) will revise the system cap for EGFs 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, and suggested that incinerators be given similar flexibility in selecting a three-month period from a three-year window in order to determine emission limits. Safety-Kleen stated that otherwise, it might have to purchase emission credits on an annual basis, even with SCR installed.

The optional 80% ESAD for incinerators is based on the emission factor used to calculate the June - August 1997 daily NO_x emissions, and not the activity level. Electric utilities in HGA are required to comply with a system cap on the basis of daily and 30-day averaging periods under §117.108 in addition to complying with the Chapter 101 mass emissions cap and trade program. Incinerators are not comparable to electric utilities in that there are no corresponding daily and 30-day emission limits for incinerators in Chapter 117. The rules include an ESAD of an 80% reduction from the emission factor used to calculate the June - August 1997 daily NO_x emissions, but this is an option in lieu of an ESAD of 0.030 lb NO_x per MMBtu. For both incinerators and electric utilities, the Chapter 101 mass emissions cap and trade program establishes annual NO_x emission allowances based on the level of activity, generally averaged over a three-year period (1997 - 1999), and the Chapter 117 ESAD. For purposes of the system cap, electric utilities are given a broader time period (any 30-day period in the nine months of July, August, and September 1997, 1998, and 1999) for determining which

time period represents the maximum heat input rate because electric utilities, unlike other sources, have no control over their level of operations.

AMMONIA AND CO EMISSIONS

BP suggested the elimination of §117.206(e)(2), which limits ammonia emissions to ten ppmv, with ammonia limits established instead through BACT review under NSR permitting for sources installing SCR.

No changes were proposed to §117.206(e)(2). However, it is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The existing ammonia limit of ten ppmv is supported by information from SCR vendors and ammonia test data for gas-fired boilers using SCR, not available when the original NO_x RACT rules were adopted in 1993. The test data are reported in Table 2-5 of *Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers* (June 1998), prepared for NESCAUM. The utility boiler operators cooperated in the development of this report by providing actual project cost, operating cost, as well as operating experience.

The commission does not expect most SCR projects to undergo BACT review because the Standard Permit for Pollution Control Projects in 30 TAC §116.617 should be available for use by SCR projects with a 30-day review time period. The only additional requirement because of the ammonia would be a demonstration to the "satisfaction of the executive director" that there

are no “significant health effects concerns resulting from an increase in emissions of any air contaminant other than those for which a National Ambient Air Quality Standard has been established.” This requirement is in §116.617(1) and can normally be satisfied by using the EPA Screen Model. Using the standard permit should eliminate much of the permitting time associated with a BACT review, provided that the ammonia emissions from the storage, handling, and slip do not create any health concerns.

It should be noted that §117.114(b) and §117.214(b)(1) require testing as specified in §117.111 and §117.211, respectively, which in turn require testing under §117.111(b) and §117.211(a)(2), respectively, for ammonia emissions on units which inject urea or ammonia into the exhaust stream for NO_x control. Similarly, §117.479(e)(2) requires testing for ammonia emissions on units which inject urea or ammonia into the exhaust stream for NO_x control. This testing is necessary to ensure compliance with the ten ppmv limit on ammonia emissions.

McAngus testified that he “estimated or calculated that there will be an additional 35.58 tpd of ammonia emitted into the atmosphere” in HGA due to ammonia slip. McAngus expressed the opinion that with an assumption of ten ppmv ammonia slip, companies are “going to have to push their SCRs as high as possible” in “an attempt to drive down the NO_x emissions.” Hamilton testified that ammonia slip is a very manageable issue and that "through the engineering design and consideration of mixing conditions, the ammonia slip can be minimized up front." Hamilton testified that ammonia slip can be further addressed during the start-up period, and commented that he is aware of "two catalyst vendors that market a catalyst which is a slip reduction catalyst." Hamilton testified further that other vendors are "working on new variants of their catalysts, which would be a 'no slip' catalyst, so there are products available today, and also other products being worked on to improve the performance" concerning ammonia slip. Hamilton testified that an individual at Southern California Edison, who had provided some of the cost estimates for one of the documents the commission relied upon for the cost estimates, indicated that annual testing for ammonia in the company's gas-fired utility boiler stacks typically results in ammonia slip below detectable levels. Hamilton testified that the document (NESCAUM's *Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers* (June 1998)) includes ammonia slip levels from utility boilers (in Table 2-5), and all were under ten ppmv.

McAngus's estimate of 35.58 tpd of increased ammonia emissions is flawed by oversimplification and is not realistic. First, not all combustion sources greater than 40 MMBtu/hr will use ammonia-based NO_x control technologies. The capabilities of combustion modifications are well documented in the literature, including the NO_x control literature cited in this preamble as well as the cost note sections of the preamble to the Chapter 117 revisions which were proposed in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275). These documents report combustion-based reductions from minimal to over 90%. Reduction capabilities as reported in the literature continue to improve. Theoretically, combustion modifications are capable of a 90% reduction, and in recent practice, a few low-NO_x burner retrofits in commercial operation are achieving this level. Use of combustion modifications will reduce the need for post-combustion controls in some cases. In addition, the ESADs for some source categories are based on use of combustion modifications. Finally, it is unrealistic to

assume an across-the-board ammonia slip of ten ppmv. In reality, as noted later in this discussion, ammonia slip is reasonably expected to be no more than five ppmv on average. Therefore, McAngus's estimate of 35.58 tpd of increased ammonia emissions is overstated by at least a factor of two.

Control of the excess ammonia generation is a part of the art and the science, as well as the economics, of post-combustion controls which utilize urea or ammonia as a reagent. A competently designed and operated post-combustion control system will minimize excess ammonia generation. Minimizing ammonia slip from SCR depends on designing the system such that injected ammonia is properly mixed and well distributed and such that the amount of catalyst is sufficient to control both NO_x and ammonia to the desired levels. An EPA study (*Applications of Selective Catalytic Reduction Technology on Coal-Fired Utility Boilers*, 1997) examined 14 coal-fired units for which ammonia slip data were available. Ammonia slip at seven of the units was in the 0.1 to 1.0 ppmv range, and ammonia slip at the remaining seven units was below five ppmv. Thus, with good design, SCR can achieve ammonia slip values well below five ppmv. Similarly, for SNCR the ammonia slip is addressed through good design (particularly, improved operating control using better signal inputs on boiler temperatures, which is now real-time optical sensing). Indeed, an SNCR vendor guarantees ammonia concentrations of no more than five ppmv ahead of the air preheater, which is a more challenging limit than an in-stack limit. The commission believes that issues related to ammonia release or concentration have been overcome through commercial development and

experience in the last ten years. Ammonia slip emissions (and therefore subsequent particulate formation) in any case will be insignificant in comparison to other existing sources of ammonia in HGA, which are estimated to be 23,862 tpy (from area sources, on-road and non-road mobile sources, and biogenics). Existing emissions of ammonia from point source are estimated to be 1,802 tpy. Assuming ammonia slip at five ppmv (i.e., approximately 15 tpd) as a worst-case estimate from ammonia slip would result in a relatively modest increase in ammonia emissions of 20%. Due to the availability of the emissions cap and trade program and due to the ability of some Tier I controls to achieve the required reductions without the need for Tier II controls, the actual number of SCRs in operation are expected to be fewer than some commenters have suggested. Therefore, the actual ammonia emissions increase would be expected to be less than previously estimated.

The commission selected an allowable ammonia slip of ten ppmv for post-combustion controls in order to balance the implementation of an effective control strategy for NO_x reduction against concern that significantly increased ammonia emissions will enhance $PM_{2.5}$ particle formation. Ammonia emissions can contribute to the production of particulate sulfate, nitrate, and ammonium which may create health effects concerns related to $PM_{2.5}$. These particulates can also degrade visibility. Current monitoring data indicate that additional ammonia emissions could increase particulate sulfate, and particulate nitrate and ammonium might also increase with a ten ppmv ammonia slip. However, the amount of any potential increase is uncertain, and until aerosol modeling is used to calculate $PM_{2.5}$ mass concentrations, the exact impact of

increased ammonia emissions cannot be known. For that reason, the commission does not believe that increasing ammonia slip beyond ten ppmv is appropriate at this time.

DEFINITIONS

It has come to the commission's attention that the definition of "boiler" in §117.10(6) inadvertently does not include large water heaters rated at greater than 2.0 MMBtu/hr because the definition refers to producing steam. These units may be as large as approximately 5.0 MMBtu/hr and are no different to control as the corresponding-sized boiler. The commission anticipates initiating rulemaking after October 15, 2001 to revise the definition of "boiler" in §117.10(6) accordingly by adding a reference to heating of water. In addition, the commission revised the lead-in paragraph to §117.10 by adding a sentence which notes that additional definitions for terms used in Chapter 117 are found in §101.1 and §3.2, concerning Definitions. This reference is intended as a courtesy to the reader who may not be familiar with the sections in which some definitions are located.

BASF commented on the definition of "electric power generating system" (EPGS) in §117.10(13). BASF stated that the definition for non-electric utility EPGSs in §117.10(13)(C) should be revised to be consistent with the definition for electric utility EPGSs in §117.10(13)(A) and (B) by stating that a non-electric utility EPGS includes only those units that generate electricity for compensation. BASF also suggested that a distinction be made between those units that generate electricity for compensation and those that receive compensation for electricity sold only during periods when industrial customers' load sources are not operated or are operating at reduced load.

The commission does not believe that the suggested change is necessary due to the revisions to §117.210(a) described later in this preamble under the heading of *SYSTEM CAPS*. However, the commission revised the definition of "electric power generating system" by adding a reference to duct burners used in turbine exhaust ducts for consistency with the new §117.101(4) and the revised §117.106(c)(3), which make the gas turbine ESAD applicable to duct burners used in turbine exhaust ducts. This change is necessary for the reasons described earlier in this preamble under the section titled SECTION BY SECTION DISCUSSION.

NASA commented on the definition of "emergency situation" in §117.10(14) and stated that it conducts operations at Ellington Field, a Federal Aviation Administration (FAA) licensed airport, and at Johnson Space Center to provide backup power to the Mission Control Center for manned space flights. NASA also stated that it employs a diesel generator to provide backup power in the event a power failure occurs during decompression treatment in the hyperbaric chamber associated with its Neutral Buoyancy Laboratory (NBL). NASA requested that these facilities be explicitly included in the definition of emergency situation.

As an FAA licensed airport, Ellington Field is one of the airports at which operation of emergency generators for the purposes of providing power in anticipation of a power failure due to severe storm activity is considered an emergency situation under §117.10(14)(A)(vi). Likewise, operation of NASA's NBL emergency generator during a power failure is considered

an emergency situation under §117.10(14)(A)(i). The commission agrees that manned space flight control centers should be treated the same as FAA licensed or military airports in the definition of "emergency situation" since continual contact with astronauts during space missions is critical to their safety, and revised §117.10(14)(A)(vi) accordingly.

ExxonMobil suggested that the definition of "emergency situation" in §117.10(14) be expanded to include additional emergency situations such as storm damage, tornado damage, and safety responses that are less than life-threatening.

Tornados and severe storms can certainly be classified as life-threatening situations which, therefore, would qualify as emergency situations under §117.10(14)(A)(v). Tornado damage or storm damage represent emergency situations if they result in power failure, floods, fire, or life-threatening situations. It is unclear what type of "safety response" ExxonMobil believes would require emergency stationary firewater pumps, generators, etc., but would not be considered life-threatening. The commission believes that the definition of "emergency situation" in §117.10(14) adequately addresses the situations which are true emergencies. Therefore, the commission made no change in response to the comment.

ERM commented on the proposed definition of "pyrolysis reactor" in §117.10(40) and suggested that the definition be revised to specify that the feedstocks (for example, ethane, propane, butane, and naphtha) are not combusted. ERM stated that this would clarify that the feedstock heating value is not considered in determining the maximum rated capacity of the pyrolysis reactor.

The commission made the suggested change.

It has come to the commission's attention that the definition of "stationary gas turbine" in §117.10(44) includes a reference to major sources which is inconsistent with the change to the definition of "unit" in §117.10(50) because "unit" now refers to major and minor sources. Therefore, the commission revised the definition of "stationary gas turbine" accordingly.

MISCELLANEOUS RULE LANGUAGE COMMENTS

The commission made several minor changes in wording for which no comments were received. Specifically, the commission revised a variety of rules for consistency with the commission's style guidelines by replacing the wording "pursuant to" with "under" or "in accordance with," as appropriate. The rules which were revised are §§117.10(2); 117.119(e)(5); 117.213(l); 117.510(a)(1)(A)(i) and (c)(1)(A)(i) and (2)(A)(ii)(II); 117.520(c)(2)(A)(ii)(I), (C)(i), and (D)(i); and 117.534(1)(B)(i) and (C)(i), and (2)(B)(i). In addition, the commission made changes to §117.107 which spell out the abbreviation for the term "MMBtu" in §117.107(a)(3), and abbreviate the term "lb/MMBtu" in §117.107(b)(1) - (3). The commission also deleted an extra "or" in §117.570(a).

Sierra-Houston stated that the rules are difficult to read and understand.

Sierra-Houston did not identify specific concerns it had regarding the rule language. The commission made every effort to eliminate errors and improve the readability of the rule.

The EPA stated that the rule may present problems with enforceability due to the granting of discretion to the executive director in §117.113(j) and (k). Section 117.113(j) allows the executive director the discretion to establish compliance plans and schedules (within a two-year time frame) for units which lose the low annual capacity factor exemption by exceeding the threshold for exemption, and §117.113(k) allows the executive director to set methods of determining compliance. Section 117.113(k) specifies that methods required in §117.113 and §117.114 must be used to determine compliance or, at the executive director's discretion, can be determined by "any commission compliance method." The EPA commented that it is unclear whether "any commission compliance method" refers to a preexisting collection of methods or even a replicable procedure and stated that EPA guidance on "Director's Discretion in State Regulations" suggests that under some circumstances, if the director selects an alternative test method, the EPA could require written notification as to which test was applied. Alternatively, the EPA suggested that the state could simply require the owner/operator of the unit to use the test method specified for the particular type of unit set forth elsewhere in the rule, omitting the option of using other commission compliance methods. Finally, the EPA suggested that this issue could be handled in the same manner as §117.121, which specifies that "...executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the EPA...."

No changes were proposed to §117.113. However, §117.103(a)(2) and (3), which are referenced in §117.113(j), are not available as low annual capacity factor exemptions from the ESADs specified in §117.106. Instead, §117.103(a) limits the applicability of the exemptions to the provisions of §117.105, §117.107, and portions of §117.113. Therefore, the EPA's concern about §117.113(j) is unwarranted. Any possible changes to §117.113(k) to address the EPA's concern about this subsection will have to be in future rulemaking because §117.113 is not open as part of the current rulemaking.

Sierra-Houston opposed the reference to the federal new source performance standards (NSPS) definitions of "modification" and "reconstruction" in §§117.203(a)(6)(D), (11)(B), and (12)(B); 117.206(c)(9)(D); 117.473(a)(2)(E), (H)(ii), and (I)(ii); and 117.475(c)(4)(A). Sierra-Houston suggested that the 30 TAC Chapter 116 definition of "modification" be used instead.

The commission believes that the Chapter 116 definition of "modification" will be more inclusive and easier to read than the corresponding definition in 40 CFR §60.14. Therefore, the commission has replaced all references to the 40 CFR §60.14 definition of "modification" with the Chapter 116 definition of "modification" in §116.10. The commission has retained the references to the definition of "reconstruction" in 40 CFR §60.15 because there is no corresponding definition of this term in Chapter 116. In addition, the commission has clarified that the term "relocated" means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older,

higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account. In addition, the commission has corrected the reference to §117.475(A) in §117.475(B) by replacing "clause (i) of this subparagraph" with "subparagraph (A) of this paragraph."

ExxonMobil commented on §117.206(h)(1), which prevents any derating of equipment (reducing the maximum rated capacity) after December 31, 2000 to change the applicability of the ESADs. ExxonMobil suggested that the rules should at least allow a physical derating (e.g., removing burners, or new burners with lower capacity) to be effective to change the applicability of ESADs.

ExxonMobil's suggested revision would undermine the purpose of the new §117.206(h)(1), which is to prevent an owner or operator in HGA from derating equipment to take advantage of a less stringent ESAD in §117.206(c). Allowing derating of equipment to occur on an open-ended basis would result in failure to achieve the anticipated NO_x emission reductions for the HGA Attainment Demonstration SIP, thereby jeopardizing the integrity of the SIP. However, the new language allows derating from what the maximum rated capacity was on December 31, 2000, provided an administratively complete permit application (as determined by the executive director) was in-house before January 2, 2001, and the maximum rated capacity authorized by the permit issued on or after January 2, 2001 is no less than the maximum rated capacity represented in the permit application as of January 2, 2001. 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).

ExxonMobil stated that §117.206(h)(1) does not indicate whether a derating can affect the applicability of the monitoring requirements (i.e., CEMS) and suggested that a physical derating should be allowed to affect the applicability of the monitoring requirements.

The maximum rated capacity on December 31, 2000 would establish the applicability of the monitoring requirements for those units in §117.213(c)(1) for which a maximum rated capacity threshold applies. If, however, an administratively complete permit application (as determined by the executive director) was in-house before January 2, 2001 to derate the unit, the revised maximum rated capacity in the permit subsequently issued by the executive director in response to that application would be used to establish the applicability of the monitoring requirements for those units in §117.213(c)(1) for which a maximum rated capacity threshold applies. If the owner or operator increased a unit's rated capacity after December 31, 2000, the higher of the two ratings would be used to establish the applicability of the monitoring requirements for those units in §117.213(c)(1) for which a maximum rated capacity threshold applies. It should be noted that the owner or operator of each unit in HGA, regardless of maximum rated capacity, must install calibrate, maintain, and operate a CEMS or PEMS if the unit is equipped with controls which inject a chemical reagent for reduction of NO_x.

BASF stated that §117.206(h)(1)(B) should be revised to extend the January 2, 2001 cutoff for administratively complete permit applications because previous rules and/or guidance did not allow derating of equipment through permitting.

It is true that the Air Permits Division would not allow an NSR permit limit by itself to limit the heat input to a unit, thereby resulting in a different ESAD. However, the Air Permits Division does receive and process requests to derate equipment. For example, an applicant may purchase a boiler rated at 120 MMBtu/hr, but want to permit the unit at 90 MMBtu/hr for NSPS purposes. In that case, the Air Permits Division would require that an actual physical modification be made to the unit so that a simple "flip of a switch" could not be used to allow the unit to operate above the new lower capacity. In addition, the 90 MMBtu/hr limit would be included as a permit restriction (and therefore federally enforceable), not just a physical restriction. Regardless of the possibility that equipment may be derated for air permitting purposes, in order to achieve the anticipated NO_x emission reductions for the HGA Attainment Demonstration SIP, it is necessary that derating of existing units not be allowed to continue indefinitely after December 31, 2000 for purposes of Chapter 117. BASF's suggestion to extend the January 2, 2001 cutoff for administratively complete permit applications would allow the derating of equipment to take advantage of a less stringent ESAD in §117.206(c), which should not be allowed for the reasons described earlier.

No comments were received on §117.206(h)(2), which establishes 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. The commission has added another example to §117.206(h)(2) which states that a unit which is classified as a stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, shall be classified as a stationary gas-fired engine for the purposes of Chapter 117. This example is broadly applicable and replaces another example which addressed a single situation in HGA. The new §117.206(h)(2) is necessary to ensure that the intended emission reductions of the program are achieved and to clarify how units which can be classified as multiple unit types are treated in Chapter 117.

No comments were received on §117.206(h)(3), which prohibits the owner or operator of units which combust fuel or waste streams containing chemical-bound nitrogen from directing these streams to flares or other units which are not subject to an ESAD. This is necessary to prevent circumvention due to the transfer of emissions associated with chemical-bound nitrogen from a unit under which these emissions would be controlled (i.e., a unit subject to an ESAD) to a unit that is not subject to the mass emissions cap and trade program (i.e., a unit without an ESAD) and therefore is uncontrolled. However, it has come to the commission's attention that this

intent is not entirely clear in §117.206(h)(3), and that §117.206(h)(3)(A) and (B) should be deleted because the mass emissions cap and trade program does not currently include a provision allowing the opt-in of units to the program. Therefore, the commission revised the rule language accordingly. In addition, the commission has added new subsections (d) - (f) to §117.475 to address circumvention issues. These new subsections for minor sources are consistent with §117.206(h) for major sources.

BP and TCC stated that the NO_x RACT final control plan required by §117.215 should be invalidated once a site is subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3. BP and TCC expressed concern that submission of revised RACT control plans might be expected, even as the Chapter 101 mass emissions cap and trade program is implemented, resulting in additional paperwork to comply with two different programs.

No changes were proposed to §117.215(e), which requires that the NO_x RACT final control plan be updated with any emission compliance measurements submitted for units using CEMS or PEMS and complying with an emission limit on a rolling 30-day average. The NO_x RACT final control plan was due by November 15, 1999 for sources in BPA and HGA, and final compliance with the RACT requirements for these sources was required by November 15, 1999. Implementation of the Chapter 101 mass emissions cap and trade program will begin on January 1, 2002. However, the emission reductions required by the mass emissions cap and trade program will not be fully implemented until April 1, 2007. The commission agrees that

updates to the NO_x RACT final control plan are no longer necessary after that date in HGA. The commission notes that guidance on the final control plans is available on the commission's website at: http://www.tnrcc.state.tx.us/oprd/forms/fcp.html. Changes that could trigger a revision to a final control plan include construction of new units with the same product output as units complying with the source cap, and changes to maximum rated capacities, applicable limits, or assigned limits.

Sierra-Houston supported the revisions to §117.479(h), which 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. Sierra-Houston stated that this requirement should apply to emergency and other engines that have some type of operating hours limit.

The commission agrees that the owner or operator of an engine claimed exempt under §117.479(a)(2)(E) or §117.203(a)(6)(D) because it operates exclusively in emergency situations needs to keep records to ensure that operation for testing or maintenance purposes is limited to 52 hours per year, based on a rolling 12-month average, and to document that all other engine operation occurs only during emergency situations, as defined in §117.10. Because run time meters have been included as standard equipment on most stationary diesel engines since approximately 1972, the commission revised §117.479(i) and §117.213(i) to include reference to engines claimed exempt under §117.479(a)(2)(E) and §117.203(a)(6)(D), respectively, because they operate exclusively in emergency situations. For consistency, the commission

also added a reference to §117.203(a)(6)(D) in §117.214(a)(2). These changes will require run time meters on these engines; however, the commission is unaware of any such engines that are not already equipped with run time meters. The commission has also revised §117.479(h) and §117.219(f)(6) to include a reference to engines claimed exempt under §117.479(a)(2)(E) and §117.203(a)(6)(D), respectively, and has added a requirement that the owner or operator keep records of the purpose of engine operation, and if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation. Finally, the commission revised the record retention time of §117.479(h) from two years to five years for consistency with §117.479(f) and (j).

No comments were received concerning §117.475(c). However, the commission revised §117.475(c) to clarify that the NO_x emission specifications of §117.475 shall be used in conjunction with §117.475(a) to determine allocations for the mass emissions cap and trade program of Chapter 101, or in conjunction with §117.475(b) to establish unit-by-unit emission specifications, as appropriate. This change is necessary because the existing language could give the impression that all units must meet the NO_x emission specifications of §117.475 on a unit-by-unit basis.

ESADS - GENERAL COMMENTS

Since pyrolysis reactors are simply a subset of the process heaters/furnaces category, the commission has combined the proposed §117.206(c)(18)(H) and (I), and has renumbered the subsequent subparagraphs in this paragraph accordingly.

BCCAAG, Dow, and TIP commented on the reference to administratively complete permit applications in §117.106(c) and (c)(5), and §117.206(c) and (c)(18). The commenters stated that the proposed wording uses the term "application" in a manner which could hold an applicant to the emission limits in a permit application, regardless of the limits in the permit as issued.

To address the commenters' concerns, the commission revised §117.206(c) and (c)(18) to clarify its intention that "the lower of any applicable permit limit" refers to limits in any permit issued before January 2, 2001, any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, or any limit in a permit by rule under which construction commenced by January 2, 2001. For consistency, the commission has likewise changed the corresponding wording in §117.475(a) and (b).

ALTERNATE ESADS

BCCA, BCCAAG, Dynegy, ED, GHASP, Reliant, and Sierra-Houston noted that the commission has committed to conduct a scientific assessment of the causes of and possible solutions to HGA's nonattainment status for ozone. GHASP commented that the possible consideration of relaxing the point source NO_x rules by June 1, 2002 is unlawful because the commission is obligated to accomplish all feasible rules in the attainment SIP, and the SIP already has a shortfall of 56 tpd of NO_x. GHASP recommended that "the unlawful commitment to relax adopted regulatory measures" be deleted, and stated that the commission should only consider relaxing the ESADs in the event that it adopts sufficient rules to achieve attainment and reaches a justifiable determination that attainment can be reached with fewer NO_x emission reductions than required by existing and proposed regulatory measures. ED and Sierra-Houston expressed similar concerns as GHASP's. ED opposed any changes in the ESADs until there is no shortfall in the required emission reductions remaining in the SIP. ED also stated that the alternate ESADs were meaningless since rulemaking would be required to make them effective, and the continuing scientific assessment may not support the 80% level of control in such a rulemaking, which would result in an entirely different set of ESADs. ED further stated that the commission appeared to prejudge the outcome of the scientific assessment by adopting alternate ESADs, even if only on a contingency basis. Sierra-Houston stated that the alternate ESADs were proposed to save industry money and not because the existing ESADs are technically or economically infeasible. BCCA, BCCAAG, Dynegy, and Reliant supported the ongoing scientific assessment of the causes of and possible solutions to HGA's nonattainment status for ozone.

The rule language commits the commission to a scientific assessment of the causes of and possible solutions to HGA's nonattainment status for ozone, and if and to the extent supported by this study 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 SIP revision involving alternate ESADs for consideration at a commission agenda no later than

June 1, 2002. The alternate ESADs were provided by BCCAAG as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described earlier in this preamble. The Consent Order specifically provides that the "Executive Director may propose . . . the Alternate ESAD Selection Rule, which shall consist of either (1) a rule confirming the . . . 80% Option, or (2) a rule establishing revised ESAD requirements for covered point sources that are different than either the 80% Option" or the ESADs in §117.106(c)(5) and §117.206(c)(1) - (17). Until the scientific assessment is completed in the spring of 2002, it cannot be known if the alternate ESADs will even be implemented and, if implemented, what level of alternate ESADs will be supported by the assessment. If these or other ESADs, or other additional rulemakings, are proposed, the commission will support that proposal with a fiscal analysis and modeling to support any changes to the HGA SIP and the rules in Chapter 117, all of which will be subject to public notice and comment.

The EPA noted that §117.106(c)(5) and §117.206(c)(18) provide that if the total emission reduction required for attainment is determined to be 80% (i.e., lower than currently anticipated), then specified relaxed emissions specifications go into effect. The EPA stated that the rules should be clearer about EPA's role in this process. The EPA commented that §117.106(c)(5) and §117.206(c)(18) require the executive director to prepare a proposed SIP revision, but that there is no reference to the EPA having to approve the relaxed emission specifications before they go into effect as part of the SIP. The EPA expressed the understanding that the commission will submit a SIP revision for any relaxed emission specifications and stated that this action is consistent with the EPA's proposed action on the NO_x point source rules.

Sections 117.106(c)(5) and 117.206(c)(18) already state that the alternate ESADs, if supported by the study, would be implemented through a proposed SIP revision. The SIP revision would be submitted to the EPA for approval. However, the commission is not aware of any of its rules that require EPA approval of a SIP revision before the rules are effective. If the EPA chooses not to approve the SIP revision, they can always enforce the previously-approved version of the rules. This in fact has happened before, in the case of the Chapter 101 upset rules.

ERM suggested that the alternate ESAD for pyrolysis reactors in §117.206(c)(18) clarify that the feedstock heating value is not considered in determining the maximum rated capacity of the pyrolysis reactor.

The commission does not believe that the suggested change is necessary due to the revised definition of "pyrolysis reactor" described earlier in this preamble under the heading of *DEFINITIONS.*

DIESEL ENGINE TESTING/MAINTENANCE OPERATING RESTRICTIONS

BP, Sierra-Houston, and TCC opposed §117.206(i) and §117.478(c), which prohibit operation for maintenance or testing of diesel and dual-fuel engines between 6:00 a.m. and noon. BP and TCC suggested that SB 5 of the 77th Legislative Session (2001) may have preempted this control measure along with the construction equipment operating restrictions of Chapter 114, Subchapter I, while Sierra-Houston stated that this will simply delay emissions. ED supported the proposed §117.206(i) and §117.478(c) and stated that these measures will reduce the impact of NO_x emissions from diesel and dual-fuel engines on HGA's peak ozone levels.

The construction equipment operating restrictions of Chapter 114 applied to the normal operations of non-road diesel construction or industrial equipment. In contrast, §117.206(i) and §117.478(c) apply to stationary diesel and dual-fuel engines (which, by definition, have to be in one place for one year to be considered stationary) and do not restrict the normal operation of these engines. Instead, these rules simply prohibit operation for maintenance or testing between 6:00 a.m. and noon. Typically, such engines which are used in emergency situations are on a timer which operates them for 30 minutes to one hour per week, often on Fridays. The timer can be easily changed such that this operation occurs outside the 6:00 a.m.-to-noon window. SB 5 of the 77th Legislature authorized the commission to delete the construction shift requirements from the SIP by October 1, 2001, but did not preempt the commission from adopting time-of-day restrictions on the operation of stationary diesel or dual-fuel engines for maintenance or testing.

The commission agrees with Sierra-Houston that §117.206(i) and §117.478(c) will delay emissions resulting from operation for maintenance or testing of diesel and dual-fuel engines

until after noon in HGA. 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. The commission made no change in response to the comments.

TECO stated that the manufacturer of its dual-fuel engine has recommended maintenance procedures that include periodic operation for over 24 continuous hours, at which time vibration information is gathered and used to determine the condition of the engine. TECO also stated that every two years the engine is run continuously for five days to allow the engine and associated equipment to heat up so that internal tolerances can be measured. Finally, TECO stated that if a repair was completed to an emergency diesel generator after 6:00 a.m., the proposed rule would not allow testing of the repair until noon, which could lead to a period of up to six hours in which the operability of emergency equipment would be unknown.

The commission revised §117.206(i) and §117.478(c) to allow operation for specific manufacturer's recommended testing requiring a run of over 18 consecutive hours, or to verify reliability of emergency equipment (e.g., emergency generators or pumps) immediately after unforeseen repairs. Routine maintenance such as an oil change is not considered to be an unforeseen repair since it can be scheduled outside the 6:00 a.m. to noon time period.

Shrader stated that operating a diesel engine without it being under load increases the NO_x emissions and also shortens the engine life by about 50%. Shrader suggested that the rule specify that engine operation for maintenance must be done under load.

NO_x formation is primarily dependent on the temperature at which combustion occurs in the engine, with lower temperatures resulting in less NO_x formation. Consequently, diesel engine manufacturers have moved to aftercooling the intake air. With an unloaded engine, the combustion temperatures will be lower and the NO_x formation also lower. While the brake-specific NO_x (grams of NO_x produced per hour divided by the engine output in brake horsepower) may be higher when operating in an unloaded condition due to the much lower

output of the engine, the engine's total NO_x output (grams per hour) will be lower than in a loaded condition.

Diesel engines have fuel injection in the form of injectors that meter in a specified amount of fuel into the cylinder based on the engine load. A governor strives to keep the engine at constant speed (revolutions per minute (RPM)) under all loads. As the load increases, more fuel is required to keep the engine at constant speed due to the counter-electromotive force of the generator (counter-torque put on the engine by the generator). As a result, at low loads very little fuel is needed to keep the engine speed constant. Less combustive energy, and thus lower combustion temperatures, result from low fuel rates at low load, and therefore total NO_x formation is reduced. Diesel engine manufacturers do not endorse the operation of engines with no load as this can cause maintenance issues and shorter engine life. There is no rule-of-thumb that quantifies the life expectancy reduction for an engine that is operated unloaded. However, the potential for reduced engine life provides strong motivation for an owner or operator to perform each operation of a diesel engine for maintenance in a loaded condition. The commission made no change in response to the comment.

SYSTEM CAPS

Reliant supported the revision to §117.108(c)(1) to allow EGFs the flexibility to choose heat input data from any system 30-day period for the baseline emission calculation.

The commission appreciates the support.

Reliant supported the revisions to §117.109 and §117.570 which give EGFs the additional flexibility to meet the system cap requirements through the use of reduction credits or through the transfer of surplus emission allowables among EGFs participating in a system cap that are in the same nonattainment area.

The commission appreciates the support.

BP stated that the commission should indicate that §117.109 is not intended to limit industrial cogeneration units to system cap trades only.

Section 117.109 applies to any EPGS which is owned or operated by a municipality or a Public Utility Commission of Texas (PUCT) regulated electric utility. Consequently, it does not apply to industrial cogeneration units. The owner or operator of an industrial cogeneration unit is provided the flexibility, under §117.213(f)(4), to use the alternative methods specified in §117.570 for purposes of complying with the system cap of §117.210.

BP and TCC opposed the daily and 30-day system cap of §117.210 and stated that it adds unnecessary complexity to the rule because sources subject to the system cap of §117.210 are also subject to the Chapter 101 mass emissions cap and trade program. BASF stated that §117.210(a) should be revised to clarify that EGFs at industrial sites are not subject to the system cap unless they are peaking units, such as peaking gas turbines or engines as defined in §117.10(35). BASF stated that the majority of stationary gas turbines at industrial sites do not meet the definition of peaking gas turbine in §117.10(35), but operate constantly at base load to provide electricity and steam to dedicated industrial customers with capacity factors greater than 90% and sell electricity to the grid only during periods when those industrial sources are either not operating or operating at reduced load.

BASF and IT noted that §117.210(a) states that EGFs are not subject to §117.210 if electric output is entirely dedicated to industrial customers, and that "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. BASF suggested that this language be changed so that it is based on the annual capacity factor of the EGF, rather than an amount of time during which electricity is sold to the grid. IT stated that there are several instances where cogeneration facilities must provide service to the grid for longer than two weeks per year at a very reduced load (on the order of less than 5.0% of capacity), and that these instances are due to the fact that many cogeneration facilities must continue to provide their industrial customer hosts with a minimum amount of steam (while generating a corresponding minimum amount of electricity to the grid) even when the host's load sources are not operating. IT stated that the level of emissions generated during these periods is very insignificant but occurs over an extended period of time (i.e., greater than two weeks). IT suggested that two weeks per year of service to the electric grid be calculated as "a generation amount equivalent to two weeks at nominal EGF nameplate capacity." Alternatively, IT suggested that "entirely dedicated" could be simply stated as "less than a specified portion (e.g., 5.0%) of generation capacity is utilized in providing service to the grid during a year" or "less than a specified portion (%) of the 1997-1999 generation total is provided to the grid during a year."

Cogeneration units generate power which in some cases is sold to the grid and in other cases is normally dedicated to use by a manufacturing process. Cogeneration units which provide power to a dedicated industrial load sometimes provide power to the grid when the manufacturing process is not operating. This type of cogeneration operation is not adding additional emissions during peak electric demand and ozone periods.

Cogeneration units which provide power to a dedicated industrial load may also provide power to the grid for longer than two weeks per year at a very reduced load because these units must continue to provide their industrial customer hosts with a minimum amount of steam (while generating a corresponding minimum amount of electricity to the grid) even when the host's load sources are not operating. This type of cogeneration operation is not adding additional emissions during peak electric demand and ozone periods since these units would be producing power if the host's load sources were operating.

However, EGFs which normally provide power to the grid during periods of peak electric demand are adding NO_x emissions during times of higher probability of ozone exceedance. Therefore, these units should comply with the daily cap. For EGFs which operate as peaking units, the 30-day average emission limit functions as a flexible but controlling limit which ensures that a specified emission level is achieved during a typical peak ozone season day. The much less stringent daily maximum limit ensures that the 30-day average is not manipulated to allow higher NO_x emissions on a single day when ozone may be a problem. An annual limit

cannot assure the level of control required on the hot summer days when ozone is most likely to form. For example, a cost-effective compliance strategy with annual limits would be to import additional power and thereby reduce operations and emissions within HGA during the non-peak ozone season. Then, when meeting the peak electric demands of a hot summer day, the peaking units would be free to emit uncontrolled, adding to ozone levels. There would be a strong economic incentive to operate in this manner, because the peaking units include both the least efficient and oldest equipment, for which it is more difficult to justify adding emission controls. The system cap addresses the ozone problem while allowing the source owners to determine the most cost-effective compliance strategy. For these reasons the commission has determined that the daily and monthly limits are necessary elements of the HGA SIP.

In response to the comments, the commission has modified the system cap requirements in §117.210 by adding another option to the last two sentences of §117.210(a). The new language excludes each EGF that generates electricity primarily for internal use, but that during 1997 and all subsequent calendar years transferred (or will transfer) that generated electricity to a utility power distribution system at a rate less than 3.85% of its actual electrical generation (which represents two weeks' worth of electrical generation per calendar year). These EGFs are base load units and are not operated at higher levels on hot summer days to meet electric demand and would not contribute additional emissions during these periods. Therefore, the commission believes it is appropriate to exclude these units from the system cap.

BCCAAG and Entergy commented on the new §117.210(c)(2) which takes into account the fact that utility EGFs generally have their highest output during the summer months, while industrial cogeneration units may have higher output during non-summer months. BCCAAG and Entergy suggested that §117.210(c)(2) be revised to clarify that the baseline period is a 30-day period for consistency with §117.210(c)(1) and §117.108.

The commission's intention is that the baseline period is a 30-day period. Consequently, the commission made the suggested change by adding "the system highest 30-day period" to the term H_i in the figure in §117.210(c)(2).

BASF suggested that §117.210 specify that NO_x emissions from duct burners (on cogeneration units subject to §117.210) are not subject to the system cap requirements if the duct burners do not generate electricity sold to the grid.

The commission does not believe that the suggested change is necessary due to the revisions to §117.210(a) described earlier in this preamble under the heading of *SYSTEM CAPS* which are intended to exclude base load EGFs from the applicability of the system cap in §117.210.

BCCAAG stated that the system caps of §117.108(c) and §117.210(c) should include a provision for the additional heat input that may be required to operate affected EGFs as a result of the installation of emission controls. BCCAAG suggested that the wording "plus the calculated additional daily heat input required by the addition of NO_x controls to comply with this chapter" be added to the 30-day baseline heat input in §117.108(c)(1) and §117.210(c)(1) and (2). BCCA stated that an example of a case where additional heat input is needed would be gas turbines in which steam injection is part of the compliance strategy.

There are inherent difficulties in such an approach, such as how to calculate the additional heat input, how enforcement personnel would be able to distinguish between controls added earlier and modifications made to comply with the ESADs, etc. In the commenter's example, it should be noted that as of November 15, 1999, gas turbines became subject to the NO_x RACT limit of 42 ppmv, which is typically met through the use of DLN or steam or water injection. The commission made no change in response to the comment.

Sempra commented on the calculation of variable H_i (heat input) in the 30-day rolling average emission cap equations of §117.210(c)(1) and (2). Sempra stated it would not expect the first two consecutive third quarters of operation of its new EGFs to be a reasonable long-term predictor of the cap values due to possibly reduced operation associated with slow-developing market demands or cooler-than-expected weather. Sempra stated that a two-year extension for baseline determination is preferable to the current baseline but may not be sufficient to allow new power plants serving a high-growth area, such as Montgomery County, to accumulate sufficient operation time to determine a representative baseline, which Sempra believes could force the more efficient new units into a situation where they must either limit operation and defer to older and dirtier units, or purchase allowances. Sempra stated that this is not consistent with promoting environmental benefits and energy reliability. Sempra expressed a preference for a seven-year extension, and also suggested the use of values based on full (100% generation) load.

In response to the comments, the commission revised the rolling 30-day average emission caps of §117.108(c)(1) and §117.210(c)(1) and (2). Specifically, the commission revised §117.108(c)(1) by modifying the method of determining level of activity for new electric utility EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. Similarly, the commission revised §117.210(c)(1), applicable during July - September, by modifying the method of determining level of activity for new non-utility EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. Finally, the commission revised §117.210(c)(2), applicable to non-utility EGFs during months other than July - September, by modifying the method of determining level of activity for new EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. For an EGF for which the system highest 30-day period in the first two years of operation occurs in months other than July - September, the owner or operator may substitute the system highest 30-day period in the six months comprising the highest three consecutive months in any two consecutive years in the first five years of operation.

For the rolling 30-day average emission caps of §117.108(c)(1) and §117.210(c)(1) and (2), the five-year period begins at the end of the adjustment period as defined in §101.350, concerning Definitions. The 180-day adjustment period addresses that period of time from first start-up to establishment of normal operating conditions for a new facility. In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period. A principal goal is to provide incentive to make emissions reductions. The commission believes that owners or operators who install and operate cleaner equipment should have the opportunity to fully integrate that equipment at a realistic level of operation that is representative of the demands that will be placed on the equipment. The commission believes that a five-year period to establish a baseline will allow this integration, while timely establishing the necessary emissions cap. This is consistent with the corresponding revisions to §101.353 which add the option of a five-year period to establish a baseline and the availability of an additional two-year period in extenuating circumstances.

EXEMPTIONS

EDI and Sierra-Houston commented on the deletion of the exemption for small (ten MW or less) electric generating units which are registered under a standard permit. Sierra-Houston supported the deletion of this exemption, while EDI requested that this exemption be retained for small electric generating units which are fired on landfill gas. EDI stated that the commission should retain the exemption because small electric generating units which are fired on landfill gas are pollution control devices; it is a replacement for the host landfill's existing control device (i.e., a flare); and it is a replacement for a part of the generation capacity of a conventional power plant. EDI stated that if the commission deletes the exemption for small electric generating units which are registered under a standard permit, it should raise the emission specification for landfill gas-fired engines and should provide credit for NO_x emission offsets.

Landfill gas-fired engines which are also electric generating units serve a dual function of control device (destruction of methane and VOC emissions) and process unit (generation of electricity). Other units serve a dual purpose, such as BIF units which are used both as boilers (steam production) and as incinerators (destruction of hazardous waste), and are subject to ESADs. Other units which are control devices, such as thermal oxidizers, are subject to ESADs. It is inequitable to create a protected source class which is not subject to the Chapter 101 mass emissions cap and trade program. Indeed, because these electric generating unit emissions would not be subject to the cap and trade program, such a protected source category would permit continued growth in emissions, thereby jeopardizing the SIP. Further, the additional generating capacity represented by small electric generating units which are fired on landfill gas would not necessarily result in a replacement of part of the generation capacity of a conventional power plant in HGA, since the additional power generated could simply be transmitted outside HGA and reduce the load on a power plant outside HGA.

The commission proposed and has adopted an ESAD of 0.60 g NO_x/hp-hr for stationary engines which are fired on landfill gas. The existing ESADs for gas-fired rich-burn and lean-burn

engines are based on use of flue gas cleanup and remain the ESADs for those engines not fired on landfill gas. However, 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.

Topsoe stated that some units which are categorized as process heaters, such as reformers, may be operated for research and development (typically described as pilot plants) rather than for production. Topsoe stated that pilot plants usually operate intermittently, in contrast to the near-continuous operation of production units. Topsoe also stated that the use of control equipment on critical process equipment can significantly affect the pilot plant's ability to reproduce customers' equipment configurations, making it difficult to develop process data that is consistent with the customers' needs. Topsoe further stated that pilot plants have been exempted in other commission rules and that pilot plants are "usually very small sources." Topsoe suggested that an exemption for pilot plants be added to §117.203.

The commission disagrees with the suggested concept of including a broad exemption for pilot plants in the rules. Such a concept would not ensure that the necessary emission reductions occur. However, based on previous comments, the commission included exemptions in Chapter 117 for certain sources in HGA which provide for a balance between the need for NO_x reductions and implementation of an effective, technically feasible control strategy. For example, §117.106(c)(4) and §117.206(c)(17) and (18)(Q) include alternative ESADs which are based on Tier I controls. The limit is the lower of any applicable permit limit or 0.06 lb/MMBtu

for any unit with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation. Also, if pilot plants are "usually very small sources," then presumably very few emission credits would be needed should the owner or operator make a decision not to equip them to meet the ESADs.

Sierra-Houston supported the 52 hours per year cutoff for operation for testing or maintenance purposes in the exemptions for existing (before October 1, 2001) stationary diesel engines in §117.203(a)(6)(D) and §117.473(a)(E).

The commission appreciates the support.

Shrader and Sierra-Houston commented on the 100 hours per year cutoff in the exemptions for existing (before October 1, 2001) stationary diesel engines in §117.203(a)(11) and §117.473(a)(H) and for new, modified, reconstructed, or relocated stationary diesel engines in §117.203(a)(12) and §117.473(a)(I). Shrader expressed concern that this would not allow enough hours of operation in the event of emergencies, such as the flooding which occurred in Houston in late spring 2001, while Sierra-Houston supported the cutoff.

The referenced exemptions are for engines which do not operate exclusively in emergency situations. For example, backup generators which also operate as peak shavers would be able to operate in peak shaving mode for approximately 48 to 74 hours per year, assuming weekly maintenance operation of 30 minutes to one hour. Existing engines which operate exclusively

in emergency situations, as defined in §117.10(14), continue to be able to operate as many hours as necessary in these situations. For any new, modified, reconstructed, or relocated stationary diesel engine placed into service in HGA on or after October 1, 2001, the commission agrees that an allowance should be made for emergency situations. Therefore, the commission revised §117.203(a)(12) and §117.473(a)(I) to specify that the 100 hours per year cutoff applies to operation in non-emergency situations. This allows operation of stationary diesel engines during an emergency situation for as many hours as the emergency situation, as defined in §117.10(14), continues to exist.

MONITORING REQUIREMENTS

BP suggested that the CEMS requirements of §117.213(e) be revised to include an option of testing under 40 CFR 75, Subpart E, because of the potential of failing an initial relative accuracy test audit (RATA) test when a source is operating at very low NO_x concentrations (e.g., five to ten ppmv). BP commented that 40 CFR 60 looks at relative accuracy in terms of percentage instead of an absolute value, whereas 40 CFR 75 allows the use of an absolute difference.

No changes were proposed to §117.213(e). However, the commission anticipates initiating rulemaking after October 15, 2001 to address this issue, along with a variety of other minor clarifications that were not included in the current rulemaking.

COMPLIANCE SCHEDULE

TECO commented on §117.520(c)(2)(A)(i), which specifies that the owner or operator must install any totalizing fuel flow meters, run time meters, and emissions monitors required by §117.214 as soon as practicable but no later than the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date). This proposed rule further specifies 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. TECO questioned when emissions monitors (CEMS or PEMS) must be installed if combustion controls, but not flue gas cleanup, are installed.

The intention is that if flue gas cleanup (such as SCR or SNCR) is installed, then the emissions monitors required by §117.214 must be installed at the time of installation of flue gas cleanup or by March 31, 2005 (whichever occurs first), regardless of whether or not combustion controls are later installed. If only combustion controls are installed on a unit, then the emissions monitors required by §117.214 must be installed by March 31, 2005. If installation of emission controls (whether combustion controls, flue gas cleanup, or both) has not begun by March 31, 2005 on a unit for which §117.214 requires emissions monitors, then the required emissions monitors must be installed by March 31, 2005. The commission revised §§117.510(c)(2)(A)(i), 117.520(c)(2)(A)(i), and 117.534(1)(A) and (2)(A) to clarify this intent.

BCCAAG stated that the compliance schedule for non-utility EGFs subject to the system cap of §117.210 limits flexibility for owners and operators by singling out this particular source category and putting it on a specific schedule, in effect accelerating EGF retrofits to a fixed schedule driven by the first or second emission reduction milestone. In contrast, BCCAAG noted that these same owners and operators had the flexibility to schedule retrofits for their non-EGF sources in the most economical and efficient manner possible. BCCAAG suggested revisions to §117.520(c)(2)(B) and (C) which would make the §117.210 system cap a requirement for a given EGF only at the time that emission controls are installed on the unit.

The commission has made the suggested revisions to §117.520(c)(2)(B) and (C). In addition, the commission made revisions to §117.210(a), described earlier in this preamble under the heading of *SYSTEM CAPS*, which are intended to exclude base load EGFs from the applicability of the system cap in §117.210. The revisions to §117.210(a) and §117.520(c)(2)(B) and (C), in conjunction with the addition of another step in the emission reduction schedule in the mass emissions cap and trade program, will afford owners and operators of base load cogeneration facilities additional flexibility in scheduling retrofits to meet the ESADs of §117.206(c).

BASF stated that the compliance schedule in §117.520(c)(2)(B)(iii) for non-utility EGFs subject to the system cap of §117.210 should be revised to coincide with the reduction schedule in §101.353(a)(3).

The existing compliance schedule is consistent with §101.353. For example, the first emission reductions must be achieved by March 31, 2004 in order to comply with the existing

§117.520(c)(2)(B)(iii)(I) and §101.353(a)(3)(C)(ii). As described in the response to the previous comment, the commission revised §117.520(c)(2)(B) and (C). These revisions ensure consistency with §101.353.

ED and GHASP objected to the addition of another step in the emission reduction schedule in §117.520(c)(2)(B)(iii) for non-utility EGFs subject to the system cap of §117.210. ED stated that the revised schedule is not as expeditious as practicable and that there is no compelling reason for the revised schedule.

The commission adopted this change to allow the affected industries more options for planning and implementing incremental reductions in emissions. This schedule is practicable given the financial and technical resources necessary by individual companies and all sources in the HGA ozone nonattainment area to comply with the required emission reductions. The 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. This change is necessary for consistency with the corresponding changes to §101.353 adopted elsewhere in this issue of the *Texas Register*. The revised compliance schedule was provided by BCCAAG as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described earlier in this preamble.

McAngus testified that “there will not be enough resources available, especially in the time frame required, for industry to be able to install, purchase, and construct all the controls required to meet the ESAD limits.” McAngus further testified that “I’m sure there will be some increase” in the marketplace in response to the increased demand for resources. “For example, catalyst manufacturers will attempt to make as much catalyst as they can so they can sell it.” However, McAngus testified that he believes that catalyst manufacturers “will build plants enough that they will be able to satisfy the replacement of catalysts,” and not “the very high levels required for the short, two- or three-year time frame.” McAngus testified that he believes this is true in the case of engineering and construction resources as well. Deason testified that there is a probable shortage of the engineering resources needed to do all of the “individual equipment-specific analysis, potential shortages of both burners and catalyst, as well as a number of other key resources that are needed to actually physically implement” the reductions in the time required. Hamilton testified that a study commissioned with a consultant by the BCCA (*Houston-Galveston Area State Implementation Plan Resource Availability Study* (August 2000)) itself did not deem the construction and engineering resources to be a critical constraint. Hamilton testified further that he had discussions with catalyst suppliers concerning resource availability, and that discussions with others revealed that some companies are interested in the business opportunity in catalyst manufacturing presented by the rules.

Deason's and McAngus's comments are based, in part, on an overestimate of the number of SCRs that will be installed and an underestimate of the time frame during which the SCRs will be installed. Point source NO_x reductions in the range of 90% require the combined use of combustion modification and flue gas controls on the majority of large combustion units. The

capabilities of both combustion modifications and flue gas controls are well documented in the NO_x control literature, including the EPA ACTs, papers at numerous meetings of research and trade organizations for industry, NO_x control vendors, constructors, and the government. These documents report combustion-based reductions from minimal to over 90%, and flue gas controls in the range of 75% to 95%. Reduction capabilities as reported in the literature continue to improve and technology has developed rapidly since the late 1980s when a number of California districts set retrofit NO_x control standards. Both combustion modifications and flue gas cleanup are established technologies. Technology is replicable so, in a true sense, the first successful SCR project was sufficient to demonstrate its feasibility. With more than 500 applications of SCR reported by 1997 and growing rapidly, in many different exhaust streams with widely varying degrees of temperature and contaminants, its technical feasibility is not in question. The combination of combustion and flue gas controls can provide overcompliance with the standards in a number of cases and will allow for meaningful choices in the selection of control strategies. Examples of units which have been retrofit to levels below the existing ESADs and further details of the technical feasibility of the ESADs can be found elsewhere in this preamble and in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)). Overcontrol on some units will enable others to be under controlled, which will result in substantial cost savings. Although the exact degree of cost savings is not determinable, one vendor has estimated the number of SCRs at 800, rather than the approximately 1,200 contemplated in the preamble to the Chapter 117 proposal published in the August 25, 2000 issue of the *Texas Register* (25

TexReg 8275). Although the number of SCRs is expected to be unprecedented, the ultimate number installed is almost certainly going to be lower as a result of the cap and trade rules, representing significant cost savings. The market-based approach embodied in the existing rules gives nearly complete freedom on how to achieve the goals and based on experience from California, will stimulate the development of new and innovative reduction technologies and strategies. The history of economics shows that the market adjusts to changing market conditions by developing additional supply when there is an increased demand for a product or service. As described earlier in this section of the preamble, the commission lengthened the compliance schedule. This will allow additional incorporation of emerging technologies, reduce labor and material availability concerns, and concurrently reduce costs.

According to a principal supplier of conventional SCR to the gas turbine market, advances in SCR technology since 1997 have resulted in a 20% reduction in the amount of catalyst needed to achieve a particular reduction target. This should further address concerns regarding catalyst availability. In addition, it should be noted that a study commissioned with a consultant by the BCCA (*Houston-Galveston Area State Implementation Plan Resource Availability Update* (April 16, 2001)) incorrectly states that the "NO_x reduction SIP for HGA has mandated the 90% NO_x reduction over a three-year period, one-third by the end of 2002, one-third by the end of 2003, and one-third by the end of 2004." In fact, the NO_x reductions required of point sources occur in annual steps beginning in 2003 and continue until 2007, a five-year period, and not over the "short, two- or three-year time frame" as stated by McAngus or assumed in the

BCCA study's discussion of catalyst availability. Therefore, McAngus and the study underestimate the time frame during which the SCRs will be installed, which in turn overstates the catalyst demand in 2003 and 2004.

Deason testified that deadline-driven milestones cause ExxonMobil to take units “out of service at unplanned outages,” which prevents them from being able to “do projects from the least cost first, to the highest and most difficult last.” Deason testified further that ExxonMobil can not delay the more expensive reductions due to milestones that are requiring ExxonMobil to do things early, and also due to their planned outage schedule.

It is unclear from this testimony exactly what milestones are requiring ExxonMobil to make emission reductions early. However, it should be noted that the commission added another step in the emission reduction schedule in §117.520(c)(2)(B)(iii) for non-utility EGFs subject to the system cap of §117.210. The commission also added another step in the emission reduction schedule in §101.353 (adopted elsewhere in this issue of the *Texas Register*). The commission adopted these changes to allow the affected industries more options for planning and implementing incremental reductions in emissions. The 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. The revised compliance schedule was provided by BCCAAG as part of the “Consent Order” submitted to Judge Margaret

Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described earlier in this preamble.

COST

BCCA and BCCAAG stated that the controls required to achieve a 90% reduction are not economically feasible, as required by the TCAA. BCCA and BCCAAG submitted an economic analysis report, *Cleaning Up Houston's Act: An Economic Evaluation of Alternative Strategies* (December 2000), which was commissioned by BCCA, and requested that it be used for the cost-benefit analysis that the commission is required to perform on all new rules. BCCAAG also submitted a January 2001 updated version of this report. BCCA and BCCAAG stated that the TCAA requires the commission to "consider the facts and circumstances bearing on the reasonableness of emissions, including the source's social and economic value, and the technical practicability and economic reasonableness of reducing or eliminating the emissions resulting from the source." A witness, Barton Smith (Smith), testified that a presentation summarizing the information contained in the report was not provided to the commission until November 10, 2000, while September 25, 2000 was the date the comment period closed for the SIP and rule proposals for which the report was developed. A witness, Jeff Saitas, testified that the economic feasibility of controls is a factor that the commission must consider as part of the SIP development process.

The commission appreciates BCCA's and BCCAAG's submittal of an economic analysis report. The commission agrees with Smith that the information contained in the BCCA report was not provided to the commission until well after the comment period closed for the SIP and

rule proposals for which the report was developed. The commission also notes that the BCCA report was not completed until after the adoption of these rules and SIP on December 6, 2000. The commission based the existing ESADs on its own analysis of cost and technical feasibility, which included seeking factual input from the regulated community. Nevertheless, a cursory review of the BCCA report revealed that while the underlying economic principles and theories outlined in the BCCA report are reasonable and theoretically sound, the application of these principles into the analysis is flawed in a variety of ways, and the report lacks sufficient documentation and detail. Some of the key issues in the report that are questionable are described in the following paragraphs.

It should be noted that the BCCA report begins with the statement that "during the past year," the authors "have been conducting a study examining the impacts" of the SIP on the Houston economy, thereby implying that the report took an entire year to prepare. Because the SIP and associated rules were not proposed until August 2000, while the report is dated December 2000 (initial version) and January 2001 (updated version), the authors' claim to have been developing their study "during the past year" is overstated.

The BCCA report asserts that the estimated total costs of the measures in the SIP are approximately $4.1 billion (year 2000 dollars) annually in 2007, yet a large number of the measures included in the cost estimate were never adopted by the commission (for example, rules for diesel emulsions, air conditioners, airport ground support equipment, and NO_x

reduction systems) or have been repealed as part of the implementation of SB 5 (relating to the Texas Emission Reduction Plan) of the 77th Texas Legislature, 2001 (construction shift rules and accelerated Tier 2/Tier 3 purchase rules, which the BCCA report cited as two of the most onerous requirements (totaling $1.8 billion in annual costs, according to the BCCA report)). Despite the fact that these control measures were never adopted or were repealed, the costs for these measures continue to be included in the BCCA reports's total estimated cost of the SIP. The costs for these control measures are irrelevant and should be deleted.

Further, the sources and estimation process for the cost study are largely undocumented. The report states that the commission's cost estimates were 'fragmentary and insufficient,' and therefore the authors consulted a number of sources in estimating the costs of the SIP, including the commission, BCCA, industry, EPA, and RCF, Incorporated. However, specific documentation for individual regulatory measures are not presented in the report. Due to the lack of documentation and explanation, it is not possible to evaluate the reasonableness of the BCCA report's individual measure cost estimates. For example, with regard to the 55 mile per hour speed limit, the report mentions the costs incurred by households (in the form of taxes and the time costs of longer commutes). One presumes (though it is not explicitly stated) that these costs are components of the BCCA report's estimates, yet the report does not quantify or even mention the benefits associated with reduced traffic accidents and reduced traffic-related fatalities due to the speed limit reduction.

In addition, the BCCA report used a discount rate of 12.5% and an expected useful equipment life of ten years to estimate the annualized portion of capital costs for the rule. The discount rate and the useful life of the equipment are unsubstantiated and presented as assumptions. The BCCA report did not include conducting sensitivity analyses to quantify the impact of these assumptions on the model results. It should be noted that an EPA guidance document, *OAQPS Control Cost Manual (EPA 453/B-96-001*, February 1996), states on page 2-11 that the control system life "typically varies from 10 to 20 years." By selecting the lower value of this range, the BCCA report may have inflated the annualized portion of control equipment capital costs, thereby exaggerating the cost of the SIP and associated rules.

The BCCA report uses the regional economic model developed by Regional Economic Models, Incorporated (REMI) to estimate the impact of the regulations on the Houston economy. Economic impacts including potential changes in employment, Regional Gross Domestic Product, local and state tax receipts, local cost of living, wages and salaries, and real disposable income per capita and impacts on business sectors and households are estimated using the REMI model. One key assumption of the analysis is that the point source measures in the SIP are so restrictive that growth in the affected sectors will cease to occur after implementation of the regulations.

Regarding the report's analysis of effects of the SIP on the Houston economy, the commission agrees that the REMI model used in the report is a reasonable one to use to analyze the

impacts of the attainment demonstration SIP on the Houston economy. The model is well documented and has been used to analyze many policy issues. However, any economic model is no better than the underlying data used as inputs to the model. The fact that a large number of regulations included in the cost estimates were never adopted by the commission (or have been repealed) and are erroneously included in the costs used to estimate the impacts; and the fact that the cost estimates are largely unsubstantiated or documented make the REMI model results dubious.

The key assumption that the point source measures prohibit growth in the affected sectors is quite significant to the REMI model results. The report states this as a fact, but provides little support for this assumption. Although a number of sensitivity analysis are conducted of alternative regulatory strategies, the BCCA report does not include a sensitivity analysis to quantify the impact of this significant assumption on the REMI model results. As described later in this preamble, Smith's testimony acknowledged that the BCCA report which he co-authored concluded that the HGA SIP rules merely slow, but do not stop, the continued growth of the Houston economy as a whole. It should also be noted that the BCCA report does not include a scenario in which the SIP is replaced by a federal implementation plan.

Regarding the BCCA report's analysis of air quality benefits of the SIP, the BCCA report uses a rollback model to estimate air quality benefits associated with the SIP. This rollback method "posits that reductions in ozone levels in excess of the background ozone level are

proportional to changes in Houston area NO_x emissions." Using this rollback method, the authors determined the ozone reductions required to meet the standard by reviewing data for the period 1997 to 1999 and comparing the fourth highest hourly ozone reading during this period to the ozone NAAQS standard in parts per billion (ppb). The authors then used this difference to construct a reduction in annual average ozone resulting from the SIP and considered the difference in these ozone levels to represent the air quality benefits of the SIP. The report acknowledges that more sophisticated air quality approaches potentially would yield different benefit values. However, the report asserts that the relatively small size of the benefits as compared to the costs of the SIP would likely be affected very little by alternative methods. The report's next step in benefits estimation is to value ozone reductions. The report's approach concentrates strictly on ozone health benefits. The report considered 21 studies included in the EPA publication "The Costs and Benefits of the Clean Air Act: 1990 - 2010" as reasonable studies to consider for estimation of the morbidity responses to ozone changes in HGA. Representative population values (such as a total Houston population of 4,218,139) are related to the study values. The report's final step was to place a monetary value on the symptoms identified in the 21 studies and to combine studies to estimate total benefits. Based upon this scenario approach, the authors concluded scenarios with total benefits of $40 million annually are most representative for the report.

Regarding the BCCA report's air quality rollback approach, the assumption that reductions in ozone are proportional to changes in NO_x emissions is questionable given that the ozone

formation process is highly nonlinear. Health benefits depend upon the distribution of ozone levels during the season and during different averaging times not explicitly considered in the report.

Although cost, benefits, and economic impacts are estimated in future years, the BCCA report's air quality estimates are based upon historical data (1997 - 1999). The report used the REMI model to estimate impacts of the SIP, and this model assumes that growth in economic activity will occur during the study period. This growth in economic activity will likely cause NO_x emissions to increase (all other factors held constant), and this growth in emissions is not accounted for in the rollback approach calculation or in benefit estimates. Likewise, implementation of regulations other than those in the SIP that may occur after the 1997 - 1999 period, thereby decreasing NO_x emissions, are not considered with this approach.

NO_x emissions are transported into and out of HGA, and this transport is not explicitly considered in the air quality method used in the BCCA report. The SIP is expected to lower NO_x emissions transported from HGA to areas outside of HGA, and the benefits of these NO_x reductions are not accounted for in the report's approach. For example, both BPA and DFW are depending on emission reductions from HGA for their attainment demonstration SIPs and associated attainment date extensions to 2007. Near nonattainment areas such as Austin and San Antonio will also benefit from the emission reductions required by the Houston attainment demonstration SIP as these areas try to avoid exceeding the one-hour ozone standard and

prepare for the implementation of the eight-hour ozone standard, yet the BCCA report failed to consider this benefit. The BCCA report also fails to take into account the benefit of the SIP as compared to the costs of the federal implementation plan that EPA is required to develop if the commission does not implement an acceptable (to EPA) attainment demonstration SIP.

Regarding the BCCA report's valuation of ozone reductions, it should be noted that the report does not consider important dose-response functions. For example, lost worker productivity is not considered as a benefit category in the report. This category is likely one of importance in HGA.

The report does not consider ozone mortality benefits in the estimate of SIP benefits. The report states that "we agree with the U.S. EPA's cautionary note regarding the possibility of spurious correlations if attempts are made to relate ozone to mortality" in the EPA publication "The Costs and Benefits of the Clean Air Act: 1990 - 2010." What the BCCA report fails to recognize is that PM mortality benefits are considered in this EPA study. The omission of ozone mortality benefits from this EPA study recognizes the possibility of double counting ozone mortality benefits when the PM mortality benefits are included in the benefits estimate. However, the interpretation in the BCCA report that ozone mortality benefits do not exist and should not be considered is incorrect.

Further, the BCCA report ignores specific categories of benefits in the benefit estimates. Ecological benefits including the beneficial impact of ozone reductions on forests and agriculture and decreased nitrogen deposition to estuaries are not addressed in the study.

Finally, the BCCA report uses population estimates in the valuation of benefits that appear to be historical estimates (note that the year is not documented in the report), rather than the forecasted population estimates for the year of analysis. For example, it seems reasonable to use forecasted 2007 populations to estimate the benefits of the SIP in 2007, and it is not clear this approach is followed in the BCCA report.

Deason testified that retrofits are more difficult due to space considerations. Deason further testified that improved burner performance to reduce NO_x emissions typically results in use of larger burners, and that as a result the burners can not be replaced in the existing hole or the floor spacing. Deason testified that this means the floor must be redesigned and that often fewer burners than originally equipped must be used, which in turn can cause reduced capacity. Deason also testified that in some cases the lack of available space would mean that an SCR would have to be elevated, and existing structural supports may be inadequate to support the SCR. In some cases what appears to be open space is actually used for maintenance turnarounds and is not actually available.

There is no one specific retrofit technology application that will be used to achieve the 90% NO_x reduction target for the point source category. Tier III emission standards are a combination of two broad types of technology, combustion modification and flue gas cleanup.

Within these broad categories, there are numerous demonstrated technologies and promising new ones moving rapidly to commercial demonstration. The diverse circumstances of several thousand point sources, most of which will have to reduce NO_x emissions even under cap and trade, will result in a variety of technologies to be applied. Replacement of existing burners is but one control technology option. The commission agrees that retrofits can be expected to be more difficult than new installations. However, as described elsewhere in this preamble as well as in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)), the existing ESADs are technically feasible. The difference between retrofits and new installations relates more to potential cost and the need for a reasonable compliance schedule to implement the retrofits than to the technical feasibility of the ESADs.

As discussed in several responses in this section as well as in the preamble to the adoption of the existing ESADs on December 6, 2000, the combination of combustion modifications and flue gas cleanup has been demonstrated to achieve emission levels equal to and surpassing the ESADs on specific units in commercial operation. There will soon be other units in SCAQMD, because a stream of new permits is issued at lower rates after a new level of NO_x is demonstrated. Some valid compliance strategies could involve reduced fuel firing and shutdown of marginally economic equipment and production lines. These strategies are not technologies, but market responses to requirements to reduce emissions.

The commission analyzed the technical feasibility of each existing ESAD and did not adopt any it believed to be technically infeasible. There are a vast number of point sources in HGA, and it would have been impractical for the commission to assess many specifics of individual emission units, such as locating available space for SCR, which will be a key factor in many retrofit applications. Because an exhaust stream can be ducted some distance to a SCR, space is ultimately a cost issue. Many of the concerns raised by the commenters with regard to the technical feasibility of the measures relate more to the potential costs. In the preamble to the adoption of the existing ESADs on December 6, 2000, the commission re-examined the issues of technical feasibility in response to public comment and, after considering the technical feasibility issues raised by commenters, adjusted several ESADs where it believed the case has been made that the level of control is not demonstrated and may be impracticable.

McAngus testified that of the nine California process heaters cited by the commission in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)) as meeting the ESADs (three at Chevron (El Cerrito) and six at Mobil (Torrance)), "we contacted each of these facilities and talked to them...." and "all three of {the Chevron} furnaces were new facilities that had been built in the early '90s" and "the SCRs had been designed into the original design of this process, so it was not a retrofit condition." McAngus testified that "in the situation for Mobil, there were six furnaces," and "five of the six" were new facilities. McAngus suggested that information from SCAQMD in response to a November 27, 2000 email was not accurate because the units referenced that are meeting the ESADs are new, not retrofits, and therefore the cost analysis "underestimated the true cost to the industry." Hamilton testified that if these process heaters were in fact new units rather than retrofits, they would be useful as examples of units that are "actually in operation achieving levels lower than the adopted emission standard," and therefore, still would be significant. Hamilton testified that the difference between retrofits and new units is "significant in terms of cost, but not in terms of technical feasibility."

The commission agrees that retrofits can be expected to be more difficult than new installations. However, as described elsewhere in this preamble as well as in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)), the existing ESADs are technically feasible. The difference between retrofits and new installations relates more to potential cost and the need for a reasonable compliance schedule to implement the retrofits than to the technical feasibility of the ESADs.

On August 15, 2001, a SCAQMD representative confirmed McAngus's testimony (described earlier in this preamble under the heading of *ESAD - ICI BOILERS AND PROCESS HEATERS*) that one of the six process heaters meeting the ESADs at the ExxonMobil refinery in Torrance is a retrofit. Specifically, the SCAQMD representative advised that heater 924 at this ExxonMobil refinery was retrofitted with an SCR unit in 1992. On August 15, 2001, the SCAQMD representative also confirmed that the three process heaters meeting the ESADs at the Chevron refinery in El Cerrito were retrofitted with a common SCR unit in 1994. The commission agrees with Hamilton that the five process heaters which were new units rather

than retrofits are useful as examples of units that are in operation achieving emission levels below the existing ESAD.

McAngus testified that "we did a review of historical BACT evaluations and looked at the costs the agency had accepted, and particularly for facilities in HGA," and "found that {BACT} costs that were acceptable to the agency... during the 1990s to the present... primarily were around $1000 per ton for NO_x emissions." McAngus testified that one case was about $11,000 per ton, but "costs that were rejected as being economically unreasonable... were anywhere from $5000 up to maybe $50,000 per ton." McAngus testified that the costs to comply with the ESADs are "much higher" than BACT costs "that typically have been accepted by the agency." McAngus testified further that BACT is only used in permits and not rules.

By definition in §116.10(3), BACT gives consideration "to the technical practicability and the economic reasonableness of reducing or eliminating emissions from the facility." Under §116.111(a)(2)(C), concerning General Application, BACT applies statewide to anyone who proposes a new facility or modifies an existing facility that will or might emit contaminants to the air in Texas. The commission agrees that BACT is only used in NSR preconstruction authorization under Chapter 116, Subchapter B, New Source Review Permits, and not Chapter 117. BACT determinations are made on a case-by-case basis.

Permit review for major source construction and major source modification in nonattainment areas requires controls that represent LAER. LAER is defined in §116.12, concerning

Nonattainment Review Definitions, to include "(A) the most stringent emission limitation which is contained in the rules and regulations of any approved SIP for a specific class or category of facility, unless the owner or operator of the proposed facility demonstrates that such limitations are not achievable; or (B) the most stringent emission limitation which is achieved in practice by a specific class or category of facilities, whichever is more stringent," and therefore is generally expected to be more stringent than BACT.

TCAA, §382.011, requires the commission to establish the level of quality to be maintained in the state's air and to control the quality of the state's air. The commission is required to "seek to accomplish" this through the control of air contaminants by "practical and economically feasible methods." The level of quality of the state's air is measured by whether the air complies with the NAAQS. According to 42 USC, §7409(b), national primary ambient air quality standards are standards which, in the judgment of the administrator of the EPA, are requisite to protect the public health. The criteria for setting the standard is protection of public health, which includes an allowance for an adequate margin of safety. The existing ESADs were developed in order for HGA to achieve attainment with the ozone NAAQS, which is a health-based standard and not a cost-based standard. As a result, the existing ESADs are technically feasible, albeit admittedly stringent, standards which represent maximal point source NO_x controls necessary for HGA to attain the ozone NAAQS. There is no question that in some cases the ESADs are more stringent than BACT or even LAER because the goals of the various requirements are different, as described earlier in this preamble. It is therefore not

unexpected that the cost to comply with the ESADs is likely to be higher than historical BACT costs.

McAngus testified that the cost estimates in the Chapter 117 cost note published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) underestimated the "true cost to the industry." McAngus testified that "many of the costs that were cited were based on data in the early 1990s, and there was no attempt to bring those costs up to" current (2000) dollars, and that "just doing a simple CPI {consumer price index} index of those numbers, the numbers were probably low by 25 to 30%, just based on inflation." McAngus testified further that "there were also other operating cost data that were using old prices as opposed to current day prices." McAngus testified that the estimated costs for FCCUs in the Chapter 117 rule proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) are inaccurate because "these costs were actually coming from what appear to be utility boiler costs, so it's a completely different category." McAngus testified that based on his conversations with people at the plants with the 13 FCCUs, the cost to retrofit FCCUs with SCR "appears to run between $20 to $60 million per installation," and that "even the installation of one of these SCRs" on an FCCU "is more than the whole cost that {the commission} estimated for the category." McAngus testified that the cost estimates for ethylene furnaces in the Chapter 117 rule proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) underestimated the costs. McAngus testified that based on his discussions with the owners of 70 of an estimated 200 ethylene furnaces, "the costs were ranging between $4 to 6 million dollars per furnace," so the cost to retrofit ethylene furnaces would be "close to $1 billion, which again is more than the entire category" of process heaters. McAngus testified that the cost estimates for gas turbines in the Chapter 117 rule proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) underestimated the costs. McAngus testified that the commission estimated the cost to retrofit turbines with SCR to average about $2,500 per ton, while his discussions with the owner of a site "that has over 30 turbines" revealed that the company had done "an engineering study and found that the costs were going to be... almost $70,000 per ton."

The commission used the most recently available cost data and cited the source of the data. While the cost of certain items may have changed since the year of the data that the commission cited, the commission continues to believe that this approach is appropriate for the reasons delineated in this response to McAngus's comments.

The commission disagrees with McAngus's claim that "many of the costs that were cited {in the Chapter 117 cost note published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275)} were based on data in the early 1990s." In fact, the vast majority (over 75%) of the estimated costs in the August 25, 2000 rule proposal were based on June 1998 or newer data. There is no reason to expect that any changes in cost from June 1998 to August 2000 would be significant, especially given that the cost of pollution control equipment has generally been declining as more controls are installed and operating experience is gained. In addition, it appears that McAngus has overstated the effect of inflation. Specifically, even if the cost of controls increased from 1993 (the earliest of the references cited in the Chapter 117 cost note published in the August 25, 2000 issue of the *Texas Register*) until 2000, what is relevant is the cost of those controls relative to other costs. For example, if the cost of an item increased

over a period of time by the average inflation rate, that item's cost would be unchanged relative to the average cost of other items.

The consumer price index (CPI) is a measure of the average change over time in the prices paid by urban consumers for a variety of consumer goods and services. The CPI is based on the experience of an average household, not on any specific family or individual, and varies by region. The CPI cannot be used as a measure of the change in pollution control equipment costs because changes in these costs are beyond the defined scope of the CPI. The CPI would not include the cost of SCR, for example, since the average household would not purchase NO_x control equipment. In addition, it is not appropriate to adjust the commission's cost estimates based on the CPI because inflation is not uniform across all categories of goods and services. In other words, the CPI cannot be used to accurately determine the price change for an individual item. For example, over the past 20-plus years gasoline prices have increased at a lower rate than the rate that would be expected if one used the CPI. Thus, the gasoline available for $1.299 per gallon today is cheaper than gasoline which cost $.999 per gallon in 1979. Gasoline prices have varied widely since 1990, both increasing and decreasing. Prices have fallen since 1990 in some categories, particularly electronics. For example, computer prices have decreased dramatically over the past 20 years, even as computer capabilities and features have expanded.

As noted earlier, the commission used the most recently available data and cited the source of the data. The costs of SCR for the coal- and gas-fired utility boilers were estimated from the cost models contained in Appendix D of *Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers*, issued by NESCAUM (June 1998). In addition, the catalyst cost for the coal-fired boilers was estimated from discussions with engineers familiar with SCR application, and the catalyst cost for gas-fired boilers was estimated based on more specific cost information from gas-fired installation in the Los Angeles area, as identified in the May 5, 2000 issue of the *Texas Register* (25 TexReg 4157). The NESCAUM report was based on actual retrofit data for electric utility boilers and included case studies of various utility boilers which were controlled with various technologies, including SCR, SNCR, gas reburn, and gas-fired low-NO_x combustion modifications. The utility boiler operators cooperated by providing actual project cost, operating cost, as well as operating experience. Because the actual cost information for completed projects was available and was provided directly by the operators, the NESCAUM report states that the costs are "anchored in reality" rather than being mere speculation.

Although the total capital cost estimate may have been imprecise, most estimates were for retrofits or replacement projects, rather than new grass roots facilities. The largest cost element was for the set of industrial boilers and process heaters in size above 40 MMBtu/hr at refineries and chemical plants, for which the presumed control approach was applying combustion modifications and SCR. As discussed in the preceding paragraph, the cost model

for these sources was based on actual retrofit data, but for electric utility boilers. The model's cost curve, from specific retrofit projects, showed sharply higher costs for the smaller utility boilers. Nonetheless, the retrofit costs may have been underestimated on average because of generally tighter spatial layouts at refineries and chemical plants as compared with small utility boilers. In particular, many of the larger refinery and chemical plant heaters have more obstacles in the form of piping and ducting of process streams than steam boilers. On the other hand, by retrofitting process heaters to the levels of the ESADs in areas such as Los Angeles, experience has been gained which will result in lower costs on subsequent applications. Flue gas cleanup technologies which operate at lower temperatures than conventional SCR, such as low temperature SCR and low temperature oxidation, offer the possibility of minimizing the amount of existing equipment which has to be taken apart.

The gas turbine costs were based on the gas turbine ACT. The EPA's ACTs normally provide retrofit cost data, but the database of retrofits for gas turbine SCRs was small, and the EPA contractor reported the cost of new units rather than retrofits. McAngus may be correct that the cost in the Chapter 117 rule proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) was underestimated for gas turbines. Because capital costs are amortized over the life of the control equipment and combined with operating costs in calculating the cost effectiveness, even if the cost were underestimated by a factor of two, the average cost effectiveness would not double. Further, previous BCCA gas turbine cost

estimates are not large enough to result in the overall rule capital cost to be underestimated by a factor of two.

In addition, it should be noted that the NO_x control technologies evaluated in the gas turbine ACT document include steam and water injection, DLN, and SCR. New control technologies are available now that were not available when the ACT was issued in 1993, including low- and high-temperature SCR, catalytic combustion, and catalytic adsorption technology. According to a principal supplier of conventional SCR to the gas turbine market, advances in SCR technology since 1997 have resulted in a 20% reduction in the amount of catalyst needed to achieve a particular reduction target, that experience gained in the design and installation of SCR units has lowered engineering costs, and that these two factors have substantially reduced SCR costs since the 1993 ACT document. Operating costs have been reduced through innovations such as using hot flue gas to preheat ammonia injection air, thereby lowering the power requirements of the ammonia injection system.

McAngus testified that he does not believe that the cap and trade market will develop because, based on his conversations with companies, “no one expects to be able to overcontrol,” and any companies that generate credits have “indicated that they’re going to keep them for themselves for a margin of error.” McAngus testified that the credits will “be too valuable to the company for them to sell” to someone else. Deason testified that ExxonMobil does not expect to have any excess credits from overcontrol.

Point source NO_x reductions in the range of 90% require the combined use of combustion modification and flue gas controls on the majority of large combustion units. The capabilities of both combustion modifications and flue gas controls are well documented in the NO_x control literature, including the EPA ACTs, papers at numerous meetings of research and trade organizations for industry, NO_x control vendors, constructors, and the government. These documents report combustion-based reductions from minimal to over 90%, and flue gas controls in the range of 75% to 95%. Reduction capabilities as reported in the literature continue to improve and technology has developed rapidly since the late 1980s when a number of California districts set retrofit NO_x control standards. Both combustion modifications and flue gas cleanup are established technologies. Technology is replicable so, in a true sense, the first successful SCR project was sufficient to demonstrate its feasibility. With more than 500 applications of SCR reported by 1997 and growing rapidly, in many different exhaust streams with widely varying degrees of temperature and contaminants, its technical feasibility is not in question. The combination of combustion and flue gas controls can provide overcompliance with the standards in a number of cases and will allow for meaningful choices in the selection of control strategies. Examples of units which have been retrofit to levels below the existing ESADs and further details of the technical feasibility of the ESADs can be found elsewhere in this preamble and in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)). Overcontrol on some units will enable others to be under controlled, which will result in substantial cost savings. Although the exact degree of cost savings is not determinable, one vendor has estimated the

number of SCRs at 800, rather than the approximately 1,200 contemplated in the preamble to the Chapter 117 proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275). Although the number of SCRs is expected to be unprecedented, the ultimate number installed is almost certainly going to be lower as a result of the cap and trade rules, representing significant cost savings. The market-based approach embodied in the existing rules gives nearly complete freedom on how to achieve the goals and based on experience from California, will stimulate the development of new and innovative reduction technologies and strategies.

Smith testified that "there will be no surplus in the point source sectors in which one could trade off and hence obtain permits for expansion or for new plants." Smith suggested that one of the most significant impacts of the attainment demonstration SIP on the Houston economy will be the inability of the petrochemical and refining industries to grow. In his testimony, Smith also acknowledged that the BCCA report which he co-authored concluded that the HGA SIP rules merely slow, but do not stop, the continued growth of the Houston economy as a whole.

The mass emissions cap and trade program will cap the level of NO_x emitted from stationary sources in HGA, thus stopping the possible growth of emissions from any new sources. Any new source will be required to find and retire allowances equal to the amount of the new source's actual NO_x emissions from sources already participating in the cap. Thus, this program does not limit growth, but it does limit growth of emissions. The commission agrees

with Smith that the HGA SIP rules will permit the continued growth of the Houston economy and notes that under the mass emissions cap and trade program, overcontrol on some units will result in credits which can be used to enable the operation of new sources or expansion of existing sources.

Experience has shown that stringent environmental controls have not wrecked an economy; the NO_x controls in SCAQMD are one example. Indeed, discernible economic effects in Los Angeles have been hard to measure. As the nature of the economy changes, there is a growing belief that environmental measures are necessary for sustained growth. The concurrence of the long economic expansion in the 1990s with significantly increased spending for air emission reductions in local areas such as in Los Angeles under RECLAIM, and nationally under 1990 FCAA mandates addressing smog, hazardous pollutants, and acid deposition, is an indication that strict air emission controls and economic growth can coexist.

Further, for those instances where the direct application of retrofit technology will not meet the desired targets, the commission has built in flexibility to comply with the ESADs, rather than requiring specific methods of controls. Because flexibility in compliance will provide a greater incentive and ability to achieve the goal of attainment, the commission is implementing the mass emissions cap and trade program. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet

emission reduction requirements. The mix of control technologies can be greater because the owner can manage activity levels of equipment and place higher levels of control on high utilization units and less controls on less utilized units. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the Chapter 117 rule proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275), the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the existing ESADs. This demonstrates that the commission has sought to accomplish its duty.

Smith testified that cost effectiveness should always be calculated at the margin (i.e., the cost per ton for the last ton of emissions reduced), as opposed to calculating average cost per ton of emissions reduced.

The commission disagrees with Smith. Typically, both the EPA and the commission report the average cost per ton of emissions reduced for specific air regulations. This standard of measurement is reasonable when looking at the overall impacts of a regulation. However, the commission agrees that the cost per ton for the last ton of emissions reduced may provide useful information for decision-making where one is considering the merits of different regulatory strategies. Generally, it depends on the context of the analysis as to which type of data may be the most meaningful. To make a blanket statement that one measure should always be used in all contexts is perhaps an overstatement of fact. Economists use a marginal approach to find optimal choices or solutions. Smith's statement may be based upon his opinion that the approach used by economists leads to an economically efficient outcome. For the economist, stating that the marginal cost per ton of emissions reduced is equivalent to the marginal benefits per ton of emissions reduced for a particular rule is essentially stating that the optimal outcome is achieved or the most economically efficient regulatory alternative is chosen.

TxDOT stated that it is possible, although not typical, that situations would arise which would require a contractor to use a stationary diesel generator to provide electricity for hot mix and concrete batch plant operations in HGA, and that in these cases the higher costs would be passed along to TxDOT in the form of higher bid prices.

While it is possible that there may be affected stationary diesel engines at hot mix asphalt and concrete plants, these plants are typically located with access to the electrical grid, particularly if they will be at a site for more than one year. Those few that are located on sites without access to the grid must be on site for a full year to be considered stationary. For a long-term construction project requiring multiple years at a single site, the commission expects that competitive bidding will ensure that higher costs do not result. For example, a contractor that obtains a site with access to the grid presumably would be able to enter a more favorable bid than a contractor without such a site.

STATUTORY AUTHORITY

The amendment is adopted 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 provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendment is also adopted 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 et seq.

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. Additional definitions for terms used in this chapter are found in §101.1 and §3.2 of this title (relating to Definitions).

(1) Annual capacity factor - The total annual fuel consumed by a unit divided by the fuel which could be consumed by the unit if operated at its maximum rated capacity for 8,760 hours per year.

(2) Applicable ozone nonattainment area - The following areas, as designated under the 1990 Federal Clean Air Act Amendments.

(A) Beaumont/Port Arthur (BPA) ozone nonattainment area - An area consisting of Hardin, Jefferson, and Orange Counties.

(B) Dallas/Fort Worth (DFW) ozone nonattainment area - An area consisting of Collin, Dallas, Denton, and Tarrant Counties.

(C) Houston/Galveston (HGA) ozone nonattainment area - An area consisting of Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties.

(3) Auxiliary steam boiler - Any combustion equipment within an electric power generating system, as defined in this section, that is used to produce steam for purposes other than generating electricity. An auxiliary steam boiler produces steam as a replacement for steam produced by another piece of equipment which is not operating due to planned or unplanned maintenance.

(4) Average activity level for fuel oil firing - The product of an electric utility unit's maximum rated capacity for fuel oil firing and the average annual capacity factor for fuel oil firing for the period from January 1, 1990 to December 31, 1993.

(5) Block one-hour average - An hourly average of data, collected starting at the beginning of each clock hour of the day and continuing until the start of the next clock hour.

(6) Boiler - Any combustion equipment fired with solid, liquid, and/or gaseous fuel used to produce steam.

(7) Btu - British thermal unit.

(8) Chemical processing gas turbine - A gas turbine that vents its exhaust gases into the operating stream of a chemical process.

(9) Continuous emissions monitoring system (CEMS) - The total equipment necessary for the continuous determination and recordkeeping of process gas concentrations and emission rates in units of the applicable emission limitation.

(10) Daily - A calendar day starting at midnight and continuing until midnight the following day.

(11) **Diesel engine** - A compression-ignited two- or four-stroke engine 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) **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) **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 boilers, auxiliary steam boilers, and stationary gas turbines (including duct burners used in turbine exhaust ducts) 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; or

(iii) Houston/Galveston;

(B) for the purposes of Subchapter B, Division 2 of this chapter (relating to Utility Electric Generation in East and Central Texas), 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 airports, military airports, or manned space flight control centers for the purposes of providing power in anticipation of a power failure due to severe storm activity.

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

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

(23) **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) **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) **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) **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) **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) **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.

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

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

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

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

(36) **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) **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) **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) **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** - A unit that produces hydrocarbon products from the endothermic cracking of feedstocks such as ethane, propane, butane, and naphtha using combustion to provide indirect heating for the cracking process.

(41) **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) **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) **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) **Stationary gas turbine** - Any gas turbine system that is gas and/or liquid fuel fired with or without power augmentation. This unit is either attached to a foundation or is portable equipment operated at a specific minor or major source for more than 90 days in any 12-month period. Two or more gas turbines powering one shaft shall be treated as one unit.

(45) **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) **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) **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) **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) **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) **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 (including any duct burner in the turbine exhaust duct), or stationary internal combustion engine, as defined in this section.

(51) **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) **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 adopted 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 the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted 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 et seq.

§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 §117.10(13)(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) utility boilers;

(2) auxiliary steam boilers;

(3) stationary gas turbines; and

(4) duct burners used in turbine exhaust ducts.

(b) The provisions of this division are applicable for the life of each affected unit within an electric power generating system or until this division or sections of this title which are applicable to an affected unit are rescinded.

§117.103. Exemptions.

(a) Reasonably available control technology. Units exempted from the provisions of §§117.105, 117.107, and 117.113 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Alternative System-wide Emission Specifications; and Continuous Demonstration of Compliance), except as may be specified in §117.113(h), (i), and (j) of this title, include the following:

(1) any new units placed into service after November 15, 1992;

(2) any utility boiler or auxiliary steam boiler with an annual heat input less than or equal to $2.2(10^{11})$ Btu per year; or

(3) stationary gas turbines and engines, which are:

(A) used solely to power other engines or gas turbines during start-ups; or

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

(b) Emission specifications for attainment demonstrations. Stationary gas turbines and engines which are used solely to power other engines or gas turbines during start-ups are exempt from the provisions of §§117.106, 117.108, and 117.113 of this title (relating to Emission Specifications for

Attainment Demonstrations; System Cap; and Continuous Demonstration of Compliance), except as may be specified in §117.113(i) of this title.

(c) Emergency fuel oil firing.

(1) The fuel oil firing emission limitations of §§117.105(c), 117.106(a), (b), and (c)(1)(B), 117.107(b), and 117.108 of this title shall not apply during an emergency operating condition declared by the Electric Reliability Council of Texas or the Southwest Power Pool, or any other emergency operating condition which necessitates oil firing. All findings that emergency operating conditions exist are subject to the approval of the executive director.

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

(3) The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction final written notification as soon as possible but no later than two weeks after the termination of emergency fuel oil firing. Final written notification shall

identify the actual dates and times that oil firing began and ended, duration of the emergency period, affected oil-fired equipment, and quantity of oil fired in each unit.

§117.106. 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 Use of Emissions Credits for Compliance).

(b) Dallas/Fort Worth. The owner or operator of each utility boiler located in the Dallas/Fort Worth (DFW) ozone nonattainment area shall ensure that emissions of NO_x do not exceed: 0.033 lb/MMBtu heat input from boilers which are part of a large DFW system, and 0.06 lb/MMBtu heat input from boilers which are part of a small DFW system, on a daily average, except as provided in §117.108 of this title or §117.570 of this title. The annual heat input exemption of §117.103(2) of this title (relating to Exemptions) is not applicable to a small DFW system.

(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 in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the following 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; and

(B) coal-fired or oil-fired, 0.040;

(2) auxiliary steam boilers:

(A) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.010;

(B) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.015; and

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

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

(A) rated at 1.0 megawatt (MW) or greater, 0.015; and

(B) rated at less than 1.0 MW:

(i) with initial start of operation on or before December 31, 2000, 0.15; and

(ii) with initial start of operation after December 31, 2000, 0.015; and

(4) as an alternative to the emission specifications in paragraphs (1) - (3) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060.

(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 subsection 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 before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications in the following subparagraphs. 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.

(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 subject to the NO_x emission limits specified in subsections (a) - (c) of this section:

(1) carbon monoxide (CO) emissions in excess of 400 ppmv at 3.0% O_2, dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units, 0.31 lb/MMBtu heat input for oil-fired units, and 0.33 lb/MMBtu for coal-fired units), based on:

(A) a one-hour average for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO; and

(2) ammonia emissions in excess of ten ppmv, based on a block one-hour averaging period.

(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) §117.108 of this title; or

(B) §117.570 of this title.

(2) An owner or operator may petition the executive director for an alternative to the CO or ammonia limits of this section in accordance with §117.121 of this title (relating to Alternative Case Specific Specifications).

(3) Section 117.107 of this title (relating to Alternative System-wide Emission Specifications) and §117.121 of this title are not alternative methods of compliance with the NO_x emission specifications of this section.

(4) In the Houston/Galveston ozone nonattainment area, the following requirements apply.

(A) For units which meet the definition of electric generating facility (EGF), the owner or operator must use both the 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) For units which do not meet the definition of EGF, the owner or operator must use the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title to comply with the NO_x emission specifications of this section.

§117.107. 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 §117.10(13)(A) of this title (relating to Definitions) would not exceed the system-wide emission limit as defined in §117.10 of this title.

(1) The following units shall comply with the individual emission specifications of §117.105 of this title and shall not be included in the system-wide emission specification:

(A) gas turbines used for peaking service subject to the emission limits of §117.105(g) of this title;

(B) auxiliary steam boilers subject to the emission limits of §117.105(a), (c), (d), or (e) of this title.

(2) Coal-fired utility boilers or steam generators shall have a separate system average under this section, limited to those units.

(3) Oil-fired utility boilers or steam generators shall have a separate system average under this section, limited to those units. The emission limit assigned to each oil-fired unit in the system shall not exceed 0.5 pound (lb) NO_x per million British thermal units (MMBtu) based on a rolling 24-hour average.

(b) The owner or operator shall establish enforceable emission limits for each affected unit in the system calculated in accordance with the maximum rated capacity averaging in this section as follows:

(1) for each gas-fired unit in the system, in lb/MMBtu:

(A) on a rolling 24-hour averaging period; and

(B) on a rolling 30-day averaging period;

(2) for each coal-fired unit in the system, in lb/MMBtu on a rolling 24-hour averaging period;

(3) for stationary gas turbines, in the units of the appropriate emission limitation of §117.105 of this title; and

(4) for each fuel oil-fired unit in the system, in lb/MMBtu on a rolling 24-hour averaging period.

(c) An owner or operator of any gaseous and liquid fuel-fired utility boiler, steam generator, or gas turbine shall:

(1) comply with the assigned maximum allowable emission rates for gas fuel while firing natural gas only;

(2) comply with the assigned maximum allowable emission rate for liquid fuel while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing, 24-hour average, allowable emission limit and the assigned liquid-firing allowable emission limit while operating on liquid and gaseous fuel concurrently.

(d) Solely for purposes of calculating the system-wide emission limit, the allowable mass emission rate for each affected unit shall be calculated from the emission specifications of §117.105 of this title, as follows.

(1) The NO_x emissions rate (in pounds per hour) for each affected utility boiler, steam generator, or auxiliary steam boiler is the product of its average activity level for fuel oil firing or maximum rated capacity for gas firing and its NO_x emission specification of §117.105 of this title.

(2) The NO_x emissions rate (in pounds per hour) for each affected stationary gas turbine is the product of the in-stack NO_x, the turbine manufacturer's rated exhaust flow rate (expressed in pounds per hour at megawatt (MW) rating and International Standards Organization (ISO) flow conditions), and $(46/28)(10^{-6})$;

Figure 30 TAC §117.107(d)(2) (No change.)

Where:

In-stack NO_x	=	NO_x (allowable) x (1 -%H_2O/100) x [20.9 -%O_2/(1 -%H_2O/100)]/5.9
NO_x (allowable)	=	the applicable NO_x emission specification of §117.105(f) or (g) of this title (expressed in parts per million by volume NO_x at 15% oxygen (O_2) dry basis)
%H_2O	=	the volume percent water in the stack gases, as calculated from the manufacturer's data, or other data as approved by the executive director, at MW rating and ISO flow conditions
%O_2	=	the volume percent O_2 in the stack gases on a wet basis, as calculated from the manufacturer's data, or other data as approved by the executive director, at the MW rating and ISO flow conditions.

§117.108. System Cap.

(a) An owner or operator of an electric generating facility (EGF) in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment areas may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.106 of this title (relating to Emission Specifications for Attainment Demonstrations) by achieving equivalent NO_x emission reductions obtained by compliance with a daily and 30-day system cap emission limitation in accordance with the requirements of this section. An owner or operator of an electric generating facility in the Houston/Galveston ozone nonattainment area must comply with a daily and 30-day system cap emission limitation in accordance with the requirements of this section.

(b) Each EGF within an electric power generating system, as defined in §117.10(13)(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)

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

Where:

i = each EGF in the electric power generating system

N = the total number of EGFs in the emission cap

H_i = (A) 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 system 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 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 January 1, 1997;

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

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

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

(II) for EGFs for which the baseline period as described in subsection (c)(1) of this section, variable (B)(i) - (iv) of this figure is not complete by December 31, 2001, no later than 90 days after completion of the baseline period.

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) A maximum daily cap shall be calculated using the following equation.

Figure: 30 TAC §117.108(c)(2) (No change.)

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

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) The NO_x emissions monitoring required by §117.113 of this title (relating to Continuous Demonstration of Compliance) for each EGF in the system cap shall be used to demonstrate continuous compliance with the system cap.

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

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

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

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

(2) use Appendix E monitoring in accordance with §117.113(d) of this title;

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

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

(B) use calculations in accordance with §117.113(f) of this title; or

(4) if the methods specified in paragraphs (1) - (3) of this subsection are not used, the owner or operator must use the maximum block one-hour emission rate as measured by the 30-day testing.

(f) The owner or operator of any EGF subject to a system cap shall maintain daily records indicating the NO_x emissions and fuel usage from each EGF and summations of total NO_x emissions and fuel usage for all EGFs under the system cap on a daily basis. Records shall also be retained in accordance with §117.119 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(g) The owner or operator of any EGF subject to a system cap shall report any exceedance of the system cap emission limit within 48 hours to the appropriate regional office. The owner or operator shall then follow up within 21 days of the exceedance with a written report to the regional office which includes an analysis of the cause for the exceedance with appropriate data to demonstrate the amount of emissions in excess of the applicable limit and the necessary corrective actions taken by the company to assure future compliance. Additionally, the owner or operator shall submit semiannual reports for the monitoring systems in accordance with §117.119 of this title.

(h) The owner or operator of any EGF subject to a system cap shall demonstrate initial compliance with the system cap in accordance with the schedule specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas).

(i) For the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, an EGF which is permanently retired or decommissioned and rendered inoperable may be included in the source cap emission limit, provided that the permanent shutdown occurred after January 1, 1999. For the Houston/Galveston ozone nonattainment area, an EGF which is permanently retired or decommissioned and rendered inoperable may be included in the source cap emission limit, provided that the permanent shutdown occurred after January 1, 2000. The source cap emission limit is calculated in accordance with subsection (b) of this section.

(j) Emission reductions from shutdowns or curtailments which have been used for netting or offset purposes under the requirements of Chapter 116 of this title may not be included in the baseline for establishing the cap.

(k) For the purposes of determining compliance with the source cap emission limit, the contribution of each affected EGF that is operating during a startup, shutdown, or upset period shall be calculated from the NO_x emission rate measured by the NO_x monitor, if operating properly. If the NO_x monitor is not operating properly, the substitute data procedures identified in subsection (e) of this section must be used. If neither the NO_x monitor nor the substitute data procedure are operating properly, the owner or operator must use the maximum daily rate measured during the initial demonstration of compliance, unless the owner or operator provides data demonstrating to the satisfaction of the executive director and the EPA that actual emissions were less than maximum emissions during such periods.

§117.109. System Cap Flexibility.

An owner or operator of a source of nitrogen oxides (NO_x) 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. In the Dallas/Fort Worth ozone nonattainment area, the value R_i 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) Start-up and shutdown records. For units subject to the start-up and/or shutdown exemptions allowed under §101.11 of this title (relating to Demonstrations), hourly records shall be made of start-up and/or shutdown events and maintained for a period of at least two years. Records shall be available for inspection by the executive director, EPA, and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type fuel burned; gross and net energy production in megawatt-hours (MW-hr); and the date, time, and duration of the event.

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

(1) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.111 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) performance evaluation conducted under §117.113 of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(c) Reporting of test results. The owner or operator of an affected unit shall furnish the Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction a copy of any 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) within 60 days after completion of such testing or evaluation; and

(2) not later than the appropriate compliance schedules specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system under §117.113 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations in this division and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar semiannual period. Written reports shall include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations (CFR), Part 60, §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the unit operating time during the reporting period:

(A) for stationary gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.113 of this title, excess emissions are computed as each one-hour period during which the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial demonstration of compliance test required by §117.111 of this title;

(B) for utility boilers complying with §117.108 of this title (relating to System Cap), excess emissions are each daily period for which the total nitrogen oxides (NO_x) emissions exceed the rolling 30-day average or the maximum daily NO_x cap;

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

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

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

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

(e) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain records of the data specified in this subsection. Records shall be kept for a period of at least five years and made available for inspection by the executive director, EPA, or local air pollution control agencies having jurisdiction upon request. Operating records for each unit shall be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or for units claimed exempt from the emission specifications based on low annual capacity factor, monthly. Records shall include:

(1) emission rates in units of the applicable standards;

(2) gross energy production in MW-hr (not applicable to auxiliary boilers);

(3) quantity and type of fuel burned;

(4) the injection rate of reactant chemicals (if applicable); and

(5) emission monitoring data, in accordance with §117.113 of this title, including:

(A) the date, time, and duration of any malfunction in the operation of the monitoring system, except for zero and span checks, if applicable, and a description of system repairs and adjustments undertaken during each period;

(B) the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, PEMS, or operating parameter monitoring systems; and

(C) actual emissions or operating parameter measurements, as applicable;

(6) the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.111 of this title; and

(7) records of hours of operation.

DIVISION 2: UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS

§117.138

STATUTORY AUTHORITY

The amendment is adopted 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 the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendment is also adopted 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 et seq.

§117.138. System Cap.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.135 of this title (relating to Emission Specifications) by achieving equivalent NO_x emission reductions obtained by compliance with a system cap emission limitation in accordance with the requirements of this section.

(b) Each unit within an electric power generating system, as defined in §117.10(13)(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) The annual average emission cap shall be calculated using the following equation.

Figure: 30 TAC §117.138(c) (No change.)

$$\text{NO}_x \text{ annual average emission cap (tons/year)} = \sum_{i=1}^{N} (H_i \times R_i)/2000$$

Where:

i	=	Each unit in the electric power generating system
N	=	The total number of units in the emission cap
H_i	=	The average of the annual heat input for each unit in the emission cap, in million British thermal units (Btu) per year, as certified to the executive director, for 1996, 1997, and 1998
R_i	=	The emission limit of §117.135 of this title

(d) The NO_x emissions monitoring required by §117.143 of this title (relating to Continuous Demonstration of Compliance) for each unit in the system cap shall be used to demonstrate continuous compliance with the system cap.

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

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

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

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

(2) use Appendix E monitoring in accordance with §117.143(d) of this title;

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

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

(B) use calculations in accordance with §117.143(f) of this title; or

(4) if the methods specified in paragraphs (1) - (3) of this subsection are not used, the owner or operator must use the maximum emission rate as measured by the testing conducted in accordance with §117.141(d) of this title (relating to Initial Demonstration of Compliance).

(f) The owner or operator of any unit subject to a system cap shall maintain daily records indicating the NO_x emissions and fuel usage from each unit and summations of total NO_x emissions and fuel usage for all units under the system cap on a daily basis. Records shall also be retained in accordance with §117.149 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(g) The owner or operator of any unit subject to a system cap shall submit annual reports for the monitoring systems in accordance with §117.149 of this title. The owner or operator shall also report any exceedance of the system cap emission limit in the annual report and shall include an analysis of the cause for the exceedance with appropriate data to demonstrate the amount of emissions in excess of the applicable limit and the necessary corrective actions taken by the company to assure future compliance.

(h) The owner or operator of any unit subject to a system cap shall demonstrate initial compliance with the system cap in accordance with the schedule specified in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(i) A unit which is permanently retired or decommissioned and rendered inoperable may be included in the source cap emission limit, provided that the permanent shutdown occurred on or after January 1, 1999. The source cap emission limit is calculated in accordance with subsection (b) of this section.

(j) Emission reductions from shutdowns or curtailments which have been used for netting or offset purposes under the requirements of Chapter 116 of this title may not be included in the baseline for establishing the cap.

(k) For the purposes of determining compliance with the source cap emission limit, the contribution of each affected unit that is operating during a startup, shutdown, or upset period shall be calculated from the NO_x emission rate measured by the NO_x monitor, if operating properly. If the NO_x monitor is not operating properly, the substitute data procedures identified in subsection (e) of this section must be used. If neither the NO_x monitor nor the substitute data procedure are operating properly, the owner or operator must use the maximum daily rate measured during the initial demonstration of compliance, unless the owner or operator provides data demonstrating to the satisfaction of the executive director and EPA that actual emissions were less than maximum emissions during such periods.

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 adopted 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 the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted 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 et seq.

§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) of this title (relating to Emission Specifications for Attainment Demonstrations; Initial Control Plan Procedures; Continuous Demonstration of Compliance; Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration; Final Control Plan Procedures for Attainment Demonstration Emission Specifications; and Notification, Recordkeeping, and Reporting Requirements), include the following:

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

(2) any commercial, institutional, or industrial boiler or process heater with a maximum rated capacity of less than 40 million Btu per hour (MMBtu/hr);

(3) heat treating furnaces and reheat furnaces. This exemption shall no longer apply to any heat treating furnace or reheat furnace with a maximum rated capacity of 20 MMBtu/hr or greater in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission

specifications for attainment demonstrations specified in §117.520 of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas);

(4) flares, incinerators, pulping liquor recovery furnaces, sulfur recovery units, sulfuric acid regeneration units, and sulfur plant reaction boilers. This exemption shall no longer apply to the following units in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title:

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

(B) pulping liquor recovery furnaces;

(5) dryers, kilns, or ovens used for drying, baking, cooking, calcining, and vitrifying. This exemption shall no longer apply to the following units in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title:

(A) magnesium chloride fluidized bed dryers; and

(B) lime kilns and lightweight aggregate kilns;

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

(A) in research and testing;

(B) for purposes of performance verification and testing;

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

(D) exclusively in emergency situations, except that operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after October 1, 2001 in the Houston/Galveston ozone nonattainment area is ineligible for this exemption. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations (CFR) §60.15 (effective December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account;

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

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

(G) as chemical processing gas turbines;

(7) stationary gas turbines with a megawatt (MW) rating of less than 1.0 MW;

(8) stationary internal combustion engines which are:

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

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

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

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

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

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

(B) has not been modified, reconstructed, or relocated on or after October 1, 2001. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

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

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

(B) meets the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 (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 §116.10 of this title and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account.

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

§117.206. Emission Specifications for Attainment Demonstrations.

(a) Beaumont/Port Arthur. No person shall allow the discharge into the atmosphere from any gas-fired boiler or process heater with a maximum rated capacity equal to or greater than 40 million British thermal units per hour (MMBtu/hr) in the Beaumont/Port Arthur ozone nonattainment area, emissions of nitrogen oxides (NO_x) in excess of the following, except as provided in subsections (f) and (g) of this section:

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

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

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

(1) gas-fired boilers with a maximum rated capacity equal to or greater than 40 MMBtu/hr, 30 parts per million by volume (ppmv) NO_x, at 3.0% oxygen (O_2), dry basis; and

(2) gas-fired and gas/liquid-fired, lean-burn, stationary reciprocating internal combustion engines rated 300 horsepower (hp) or greater, 2.0 grams NO_x per horsepower hour (g NO_x/hp-hr) and 3.0 g carbon monoxide (CO)/hp-hr.

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

(1) gas-fired boilers:

(A) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.010 lb NO_x per MMBtu;

(B) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.015 lb NO_x per MMBtu; and

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

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

(A) 13 ppmv NO_x at 0.0% O_2, dry basis;

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

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

(i) install and certify a NO_x CEMS or PEMS as specified in §117.213(e) or (f) of this title (relating to Continuous Demonstration of Compliance) no later than June 30, 2001;

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

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

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

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

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

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

(i) 0.030 lb NO_x per MMBtu; or

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

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

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

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

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

(8) process heaters:

(A) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.010 lb NO_x per MMBtu;

(B) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.015 lb NO_x per MMBtu; and

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

(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, except as specified in subparagraph (C) of this paragraph:

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

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

(C) dual-fuel engines:

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

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

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

(i) placed into service before October 1, 2001 which have not been modified, reconstructed, or relocated on or after October 1, 2001, 11.0 g NO_x/hp-hr. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account; and

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(10) stationary gas turbines:

(A) rated at 1.0 megawatt (MW) or greater, 0.015 lb NO_x per MMBtu; and

(B) 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; and

(ii) with initial start of operation after December 31, 2000, 0.015 lb NO_x per MMBtu;

(11) duct burners used in turbine exhaust ducts, 0.015 lb NO_x per MMBtu;

(12) pulping liquor recovery furnaces, either:

(A) 0.050 lb NO_x per MMBtu; or

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

(13) kilns:

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

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

(14) metallurgical furnaces:

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

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

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

(16) incinerators, either of the following:

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

(B) 0.030 lb NO_x per MMBtu;

(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 subsection 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 before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications in the following subparagraphs. 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.

(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% O_2, 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, 0.060 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:

(i) other than 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; and

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

(I) 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;

(J) stationary gas turbines:

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

(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;

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

(L) pulping liquor recovery furnaces, either:

(i) 0.050 lb NO_x per MMBtu; or

(ii) 1.08 lb NO_x per ADTP;

(M) 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;

(N) metallurgical furnaces:

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

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

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

(P) 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

(Q) 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) NO_x averaging time.

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

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

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

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

(iii) a block one-hour average, in pounds per hour, for boilers and process heaters, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in lb NO_x per MMBtu; and

(B) if the unit is not operated with a NO_x CEMS or PEMS under §117.213 of this title, a block one-hour average, in the units of the applicable standard. Alternatively for boilers and process heaters, the emission limits may be applied in lbs per hour, as specified in subparagraph (A)(iii) of this paragraph.

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

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

(1) carbon monoxide (CO), 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines);

(A) on a rolling 24-hour averaging period, for units equipped with CEMS or PEMS for CO; and

(B) on a one-hour average, for units not equipped with CEMS or PEMS for CO; and

(2) ammonia emissions, ten ppmv on a block one-hour averaging period;

(3) The correction of CO emissions to 3.0% O_2, dry basis, in paragraph (1) of this subsection does not apply to the following units:

(A) lightweight aggregate kilns; and

(B) boilers and process heaters operating at less than 10% of maximum load and with stack O_2 in excess of 15% (i.e., hot-standby mode).

(4) The CO limits in paragraph (1) of this subsection do not apply to the following units:

(A) stationary internal combustion engines subject to subsection (b)(2) of this section or §117.205(e) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT));

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

(C) incinerators subject to the CO limits of one of the following:

(i) §111.121 of this title (relating to Single-, Dual-, and Multiple-Chamber Incinerators);

(ii) §113.2072 of this title (relating to Emission Limits) for hospital/medical/infectious waste incinerators; or

(iii) 40 CFR Part 264 or 265, Subpart O, for hazardous waste incinerators.

(f) Compliance flexibility.

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

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

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

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

(2) Section 117.221 of this title is not an applicable method of compliance with the NO_x emission specifications of this section.

(3) An owner or operator may petition the executive director for an alternative to the CO or ammonia limits of this section in accordance with §117.221 of this title.

(4) In the Houston/Galveston ozone nonattainment area, an owner or operator may not use the alternative methods specified in §§117.207, 117.223, and 117.570 of this title to comply with the NO_x emission specifications of this section. The owner or operator shall use the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title to comply with the NO_x emission specifications of this section, except that EGFs shall also comply with the daily and 30-day system cap emission limitations of §117.210 of this title. An owner or operator may use the alternative methods specified in §117.570 of this title for purposes of complying with §117.210 of this title.

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

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

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

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

(1) the maximum rated capacity used to determine the applicability of the emission specifications in subsection (c) of this section shall be:

(A) the greater of the following:

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

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

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

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

31, 2000, but subsequently is authorized to operate as a dual-fuel engine, shall be classified as a stationary gas-fired engine for the purposes of this chapter; and

(3) the owner or operator of a unit subject to an emission specification in subsection (c) of this section which, as of December 31, 2000, combusts one or more fuel or waste streams containing chemical-bound nitrogen shall not re-direct these streams to flares or other units which are not subject to an emission specification in subsection (c) of this section.

(i) Operating restrictions. In the Houston/Galveston ozone nonattainment area, no person shall start or operate any stationary diesel or dual-fuel engine for testing or maintenance between the hours of 6:00 a.m. and noon, except:

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

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

§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. Alternatively, an EGF that generates electricity primarily for internal use, but that during 1997 and all subsequent calendar years transferred (or will transfer) that generated electricity to a utility power distribution system at a rate less than 3.85% of its actual electrical generation is not subject to the requirements of this section.

(b) Each EGF that is subject to the NO_x emission rates of §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations) must be included in the system cap.

(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)

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

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;

(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;

(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;

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

(E) In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period described in subsection (c)(1) of this section, variable (A) -

(D) of this figure. Applications seeking an alternate baseline period must be submitted by the owner or operator of the EGF to the executive director:

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

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

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

(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 system highest 30-day period in the nine months comprising the highest three consecutive months in each year of the 1997 - 1999 period;

(B) For 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;

(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;

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

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

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

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

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

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

Figure: 30 TAC §117.210(c)(3)

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

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.

(d) The NO_x emissions monitoring required by §117.213 of this title (relating to Continuous Demonstration of Compliance) for each EGF in the system cap shall be used to demonstrate continuous compliance with the system cap.

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

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

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

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

(2) use Appendix E monitoring in accordance with §117.113(d) of this title (relating to Continuous Demonstration of Compliance);

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

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

(B) use calculations in accordance with §117.113(f) of this title; or

(4) if the methods specified in paragraphs (1) - (3) of this subsection are not used, the owner or operator must use the maximum block one-hour emission rate as measured by the 30-day testing.

(f) The owner or operator of any EGF subject to a system cap shall maintain daily records indicating the NO_x emissions and fuel usage from each EGF and summations of total NO_x emissions and fuel usage for all EGFs under the system cap on a daily basis. Records shall also be retained in accordance with §117.219 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(g) The owner or operator of any EGF subject to a system cap shall report any exceedance of the system cap emission limit within 48 hours to the appropriate regional office. The owner or operator shall then follow up within 21 days of the exceedance with a written report to the regional office which includes an analysis of the cause for the exceedance with appropriate data to demonstrate the amount of emissions in excess of the applicable limit and the necessary corrective actions taken by the company to assure future compliance. Additionally, the owner or operator shall submit semiannual reports for the monitoring systems in accordance with §117.219 of this title.

(h) The owner or operator of any EGF subject to a system cap shall demonstrate initial compliance with the system cap in accordance with the schedule specified in §117.520 of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas).

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

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

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

(k) For the purposes of determining compliance with the source cap emission limit, the contribution of each affected EGF that is operating during a startup, shutdown, or upset period shall be calculated from the NO_x emission rate measured by the NO_x monitor, if operating properly. If the NO_x monitor is not operating properly, the substitute data procedures identified in subsection (e) of this section must be used. If neither the NO_x monitor nor the substitute data procedure are operating properly, the owner or operator must use the maximum daily rate measured during the initial demonstration of compliance, unless the owner or operator provides data demonstrating to the satisfaction of the executive director and the EPA that actual emissions were less than maximum emissions during such periods.

§117.213. Continuous Demonstration of Compliance.

(a) Totalizing fuel flow meters. The owner or operator of units listed in this subsection shall install, calibrate, maintain, and operate a totalizing fuel flow meter 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.

(1) The units are the following:

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

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

(I) boilers;

(II) process heaters;

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

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

(ii) stationary, reciprocating internal combustion engines not exempt by §117.203(a)(6) or (8) of this title (relating to Exemptions), or §117.205(h)(9) or (10) of this title;

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

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

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

(i) boilers (excluding wood-fired boilers);

(ii) process heaters;

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

(iv) duct burners used in turbine exhaust ducts;

(v) stationary, reciprocating internal combustion engines;

(vi) stationary gas turbines;

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

(viii) lime kilns;

(ix) lightweight aggregate kilns;

(x) heat treating furnaces;

(xi) reheat furnaces;

(xii) magnesium chloride fluidized bed dryers; and

(xiii) incinerators.

(2) As an alternative to the fuel flow monitoring requirements of this subsection, units operating with a nitrogen oxides (NO_x) and diluent continuous emissions monitoring system (CEMS) under subsection (e) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 CFR 60, Appendix B, Performance Specification 6 or 40 CFR 75, Appendix A.

(b) Oxygen (O_2) monitors.

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

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

(B) process heaters with a rated heat input:

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

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

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

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

(B) process heaters operating with a carbon dioxide (CO_2) CEMS for diluent monitoring under subsection (e) of this section; and

(C) wood-fired boilers.

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

(c) NO_x monitors.

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

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

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

(C) boilers and process heaters located in the Beaumont/Port Arthur ozone nonattainment area which are vented through a common stack and the total rated heat input from the units combined is greater than or equal to 250 MMBtu/hr and the annual heat input combined is greater than $2.2(10^{11})$ Btu/yr;

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

(E) units which use a chemical reagent for reduction of NO_x;

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

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

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

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

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

(d) Carbon monoxide (CO) monitoring. The owner or operator shall monitor CO exhaust emissions from each unit listed in subsection (c)(1) of this section using one or more of the following methods:

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

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

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

(2) sample CO as follows:

(A) with a portable analyzer (or 40 CFR 60, Appendix A reference method test apparatus) after manual combustion tuning or manual burner adjustments conducted for the purpose of minimizing NO_x emissions whenever, following such manual changes, either of the following occur:

(i) NO_x emissions are sampled with a portable analyzer or 40 CFR 60, Appendix A reference method test apparatus; or

(ii) the resulting NO_x emissions measured by CEMS or predicted by PEMS are lower than levels for which CO emissions data was previously gathered; and

(B) sample CO emissions using the test methods and procedures of 40 CFR 60 in conjunction with any relative accuracy test audit of the NO_x and diluent analyzer.

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

(1) The CEMS shall meet the requirements of 40 CFR Part 60 as follows:

(A) Section 60.13;

(B) Appendix B:

(i) Performance Specification 2, for NO_x;

(ii) Performance Specification 3, for diluent; and

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

(C) After the final compliance date, audits in accordance with §5.1 of Appendix F, quality assurance procedures for NO_x, CO and diluent analyzers, except that a cylinder gas audit or relative accuracy audit may be performed in lieu of the annual relative accuracy test audit (RATA) required in §5.1.1.

(2) Monitor diluent, either O_2 or CO_2, unless using an exhaust flow meter as provided in subsection (a)(2) of this section.

(3) One CEMS may be shared among units, provided:

(A) the exhaust stream of each unit is analyzed separately; and

(B) the CEMS meets the certification requirements of paragraph (1) of this subsection for each exhaust stream.

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

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

(1) The PEMS must predict the pollutant emissions in the units of the applicable emission limitations of this division.

(2) Monitor diluent, either O_2 or CO_2:

(A) using a CEMS

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

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

(B) using a PEMS.

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

(4) The owner or operator may vary from 40 CFR 75, Subpart E if the owner or operator:

(A) demonstrates to the satisfaction of the executive director and EPA that the alternative is substantially equivalent to the requirements of 40 CFR 75, Subpart E; or

(B) demonstrates to the satisfaction of the executive director that the requirement is not applicable.

(5) The owner or operator may substitute the following as an alternative to the test procedure of Subpart E for any unit:

(A) perform the following alternative initial certification tests:

(i) conduct initial RATA at low, medium, and high levels of the key operating parameter affecting NO_x using 40 CFR Part 60, Appendix B:

(I) Performance Specification 2, subsection 4.3 (pertaining to NO_x);

(II) Performance Specification 3, subsection 2.3 (pertaining to O_2 or CO_2); and

(III) Performance Specification 4, subsection 2.3 (pertaining to CO), for owners or operators electing to use a CO PEMS; and

(ii) conduct an F-test, a t-test, and a correlation analysis using 40 CFR 75, Subpart E at low, medium, and high levels of the key operating parameter affecting NO_x;

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

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

(III) The t-test and the correlation analysis shall be performed using all data collected at the three tested levels;

(B) further demonstrate PEMS accuracy and precision for at least one unit of a category of equipment by performing RATA and statistical testing in accordance with subparagraph (A) of this paragraph for each of three successive quarters, beginning:

(i) no sooner than the quarter immediately following initial certification; and

(ii) no later than the first quarter following the final compliance date; and

(C) after the final compliance date, perform RATA for each unit:

(i) at normal load operations;

(ii) using the Performance Specifications of paragraph (5)(A)(i)(I) - (III) of this subsection; and

(iii) at the following frequency:

(I) semiannually; or

(II) annually, if following the first semiannual RATA, the relative accuracy during the previous audit for each compound monitored by PEMS is less than or equal to 7.5% of the mean value of the reference method test data at normal load operation; or alternatively,

(-a-) for diluent, is no greater than 1.0% O_2 or CO_2, for diluent measured by reference method at less than 5% by volume; or

(-b-) for CO, is no greater than 5 parts per million by volume.

(6) The owner or operator shall, for each alternative fuel fired in a unit, certify the PEMS in accordance with paragraph (5)(A) of this subsection unless the alternative fuel effects on NO_x, CO, and O_2 (or CO_2) emissions were addressed in the model training process.

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

(g) Engine monitoring. The owner or operator of any stationary gas engine subject to the emission specifications of this division shall stack test engine NO_x and CO emissions as follows.

(1) Engines not using NO_x CEMS or PEMS.

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

(B) Sample:

(i) on a biennial calendar basis; or

(ii) within 15,000 hours of engine operation after the previous emission test, under the following conditions:

(I) install and operate an elapsed operating time meter; and

(II) submit, in writing, to the executive director and any local air pollution agency having jurisdiction, biennially after the initial demonstration of compliance:

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

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

(C) Gas-fired emergency generators are not required to conduct the testing specified in subparagraph (B) of this paragraph.

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

(h) Monitoring for stationary gas turbines less than 30 MW. The owner or operator of any stationary gas turbine rated less than 30 MW using steam or water injection to comply with the emission specifications of §117.205 or §117.207 of this title (relating to Alternative Plant-wide Emission Specifications) shall either:

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

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

(A) The system shall be accurate to within ± 5.0%.

(B) The steam-to-fuel or water-to-fuel ratio monitoring data shall constitute the method for demonstrating continuous compliance with the applicable emission specification of §117.205 or §117.207 of this title.

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

(i) Run time meters. The owner or operator of any stationary gas turbine or stationary internal combustion engine claimed exempt using the exemption of §117.205(h)(2) or §117.203(a)(6)(D), (11), or (12) of this title shall record the operating time with an elapsed run time meter. Any run time meter installed on or after October 1, 2001 shall be non-resettable.

(j) Hydrogen (H_2) monitoring. The owner or operator claiming the H_2 multiplier of §117.205(b)(6), §117.207(g)(4), or (h) of this title shall sample, analyze, and record every three hours the fuel gas composition to determine the volume percent H_2.

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

(2) Fuel gas analysis shall be tested according to American Society of Testing and Materials (ASTM) Method D1945-81 or ASTM Method D2650-83, or other methods which are demonstrated to the satisfaction of the executive director and the EPA to be equivalent.

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

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

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

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

(k) Data used for compliance.

(1) After the initial demonstration of compliance required by §117.211 of this title, the methods required in this section shall be used to determine compliance with the emission specifications of §117.205 or §117.206(a) or (b) of this title. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission limitations.

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

(l) Enforcement of NO_x RACT limits. If compliance with §117.205 of this title is selected, no unit subject to §117.205 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117.205 of this title. If compliance with §117.207 of this title is selected, no unit subject to §117.207 of this title shall be operated at an emission rate higher than that approved by the executive director under §117.215(b) of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology).

(m) Loss of NO_x RACT exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.205(h)(2) of this title (relating to Definitions), shall notify the executive director within seven days if the Btu/yr or hour-per-year limit specified in §117.10 of this title, as appropriate, is exceeded.

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

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

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

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

(a) Monitoring requirements.

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

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

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

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

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

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

(b) Testing requirements.

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

(2) Each stationary internal combustion engine shall be checked for proper operation of the engine by recorded measurements of NO_x and CO emissions at least quarterly and as soon as practicable within two weeks after each occurrence of engine maintenance which may reasonably be expected to increase emissions, oxygen (O_2) sensor replacement, or catalyst cleaning or catalyst replacement. Stain tube indicators specifically designed to measure NO_x concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack

temperature, and three sets of concentration measurements are made and averaged. Portable NO_x analyzers shall also be acceptable for this documentation. Quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours. This exemption does not diminish the requirement to test emissions after the installation of controls, major repair work, and any time the owner or operator believes emissions may have changed.

(c) Emission allowances.

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

(2) For units not operating with continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS), the following apply.

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

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

(C) The NO_x emission rate determined by the retesting shall establish a new emission factor to be used to calculate actual emissions instead of the previously determined emission factor used to calculate actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

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

§117.219. Notification, Recordkeeping, and Reporting Requirements.

(a) Start-up and shutdown records. For units subject to the start-up and/or shutdown exemptions allowed under §101.11 of this title (relating to Demonstrations), hourly records shall be made of start-up and/or shutdown events and maintained for a period of at least two years. Records shall be available for inspection by the executive director, EPA, and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type of fuel burned; and the date, time, and duration of the procedure.

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

(1) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.211 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) relative accuracy test audit (RATA) conducted under §117.213 of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(c) Reporting of test results. The owner or operator of an affected unit shall furnish the Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction a copy of any 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) within 60 days after completion of such testing or evaluation; and

(2) not later than the compliance schedule specified in §117.520 of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system under §117.213 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations of this division (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) and the monitoring system performance. For sources in the Houston/Galveston ozone nonattainment area 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), which are no longer subject to the emission limitations of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), the report is only a monitoring system report as specified in paragraph (3) of this subsection. All reports shall be postmarked or received by the 30th day following the end of each calendar semiannual period. Written reports shall include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations, Part 60, §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the unit operating time during the reporting period.

(A) For stationary gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.213(h)(2) of this title, excess emissions are computed as each one-hour period during which the average steam or water injection rate is below the level defined by the control algorithm as necessary to achieve compliance with the applicable emission limitations in §117.205 of this title.

(B) For units complying with §117.223 of this title (relating to Source Cap), excess emissions are each daily period for which the total nitrogen oxides (NO_x) emissions exceed the rolling 30-day average or the maximum daily NO_x cap.

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

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

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

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

operating time for the reporting period or the CEMS, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(e) Reporting for engines. The owner or operator of any rich-burn engine subject to the emission limitations in §§117.205, 117.206 (relating to Emission Specifications for Attainment Demonstrations), or 117.207 (relating to Alternative Plant-wide Emission Specifications) of this title shall report in writing to the executive director on a quarterly basis any excess emissions and the air- fuel ratio monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar semiannual period. Written reports shall include the following information:

(1) the magnitude of excess emissions (based on the quarterly emission checks of §117.208(d)(7) of this title (relating to Operating Requirements) and the biennial emission testing required for demonstration of emissions compliance in accordance with §117.213(g) of this title, computed in pounds per hour and grams per horsepower-hour, any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the engine operating time during the reporting period;

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

(f) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain written or electronic records of the data specified in this subsection. Such records 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) for each unit subject to §117.213(a) of this title, records of annual fuel usage;

(2) for each unit using a CEMS or PEMS in accordance with §117.213 of this title, monitoring records of:

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

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

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

(ii) pounds or tons per day; or

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

(i) lb/MMBtu heat input or in the units of the applicable emission specification in §117.206(c) of this title; and

(ii) pounds or tons per day;

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

(A) emissions measurements required by:

(i) §117.208(d)(7) of this title; and

(ii) §117.213(g) of this title; and

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

(4) for each stationary gas turbine monitored by steam-to-fuel or water-to-fuel ratio in accordance with §117.213(h) of this title, records of hourly:

(A) pounds of steam or water injected;

(B) pounds of fuel consumed; and

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

(5) for hydrogen (H_2) fuel monitoring in accordance with §117.213(j) of this title, records of the volume percent H_2 every three hours;

(6) for units claimed exempt from emission specifications using the exemption of §117.205(h)(2) or §117.203(a)(6)(D), (11), or (12) of this title (relating to Exemptions), either records of monthly:

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

(B) hours of operation, for exemptions based on hours per year of operation. In addition, for each engine claimed exempt under §117.203(a)(6)(D) of this title, written records shall be maintained of the purpose of engine operation and, if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation;

(7) Records of carbon monoxide measurements specified in §117.213(d)(2) of this title;

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

(9) records of the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.211 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 adopted 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 the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted 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 et seq.

§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;

(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;

(2) the following stationary engines:

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

(B) engines used in research and testing;

(C) engines used for purposes of performance verification and testing;

(D) engines used solely to power other engines or gas turbines during start-ups;

(E) engines operated exclusively in emergency situations, except that operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after October 1, 2001 is ineligible for this exemption. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations (CFR) §60.15 (effective December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account;

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

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

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

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

(ii) have not been modified, reconstructed, or relocated on or after October 1, 2001. For the purposes of this clause, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

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

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

(ii) meet the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 (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 §116.10 of this title and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

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

(b) At any stationary source of nitrogen oxides (NO_x) which is not subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the following are exempt from the requirements of this division, except for the totalizing fuel flow requirements of §117.479(a), (d), and (g)(1) of this title:

(1) any boiler or process heater with a maximum rated capacity greater than 2.0 MMBtu/hr and less than 5.0 MMBtu/hr that has an annual heat input less than or equal to 1.8 (10^9) Btu per calendar year; and

(2) any boiler or process heater with a maximum rated capacity equal to or greater than 5.0 MMBtu/hr that has an annual heat input less than or equal to 9.0 (10^9) Btu per calendar year.

§117.475. 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 in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications 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 in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications in subsection (c) of this section. The averaging time shall be as follows:

(1) if the unit is operated with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.479(c) of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements), either as:

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

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

(C) a block one-hour average, in pounds per hour, for boilers and process heaters, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in pound NO_x per million British thermal units (lb/MMBtu); or

(2) if the unit is not operated with a NO_x CEMS or PEMS under §117.479(c) of this title, a block one-hour average, in the units of the applicable standard.

(c) The following NO_x emission specifications shall be used in conjunction with subsection (a) of this section to determine allocations for Chapter 101, Subchapter H, Division 3 of this title, or in conjunction with subsection (b) of this section to establish unit-by-unit emission specifications, as appropriate:

(1) from boilers and process heaters, 0.036 lb/MMBtu heat input (or alternatively, 30 parts per million by volume (ppmv), at 3.0% oxygen (O_2), dry basis);

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

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

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

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

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

(A) placed into service before October 1, 2001 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 §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations §60.15 (effective December 16, 1975), respectively, and the term “relocated” means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account; and

(B) for engines not subject to subparagraph (A) of this paragraph:

(i) with a horsepower 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) as an alternative to the emission specifications in paragraphs (1) - (5) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu heat input.

(d) The maximum rated capacity used to determine the applicability of the emission specifications in subsection (c) of this section shall be:

(1) the greater of the following:

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

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

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

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

(f) The owner or operator of a unit subject to an emission specification in subsection (c) of this section which, as of December 31, 2000, combusts one or more fuel or waste streams containing chemical-bound nitrogen shall not re-direct these streams to flares or other units which are not subject to an emission specification in subsection (c) of this section.

§117.478. Operating Requirements.

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

(b) All units 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) Each boiler, except for wood-fired boilers, shall be operated with oxygen (O_2), carbon monoxide (CO), or fuel trim.

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

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

(5) Each stationary internal combustion engine shall be checked for proper operation of the engine by recorded measurements of NO_x and CO emissions at least quarterly and as soon as practicable

within two weeks after each occurrence of engine maintenance which may reasonably be expected to increase emissions, O_2 sensor replacement, catalyst cleaning, or catalyst replacement. Stain tube indicators specifically designed to measure NO_x concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x analyzers shall also be acceptable for this documentation. Quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours. This exemption does not diminish the requirement to test emissions after the installation of controls, major repair work, and any time the owner or operator believes emissions may have changed.

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

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

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

§117.479. Monitoring, Recordkeeping, and Reporting Requirements.

(a) Totalizing fuel flow meters.

(1) The owner or operator of each unit subject to the emission limitations of §117.475 of this title (relating to Emission Specifications) 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) As an alternative to the fuel flow monitoring requirements of this subsection, units operating with a nitrogen oxides (NO_x) and diluent continuous emissions monitoring system (CEMS) under subsection (c) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (CFR) 60, Appendix B, Performance Specification 6 or 40 CFR 75, Appendix A.

(b) Oxygen (O_2) monitors. If the owner or operator installs an O_2 monitor, the criteria in §117.213(e) of this title (relating to Continuous Demonstration of Compliance) should be considered the appropriate guidance for the location and calibration of the monitor.

(c) NO_x monitors. If the owner or operator installs a CEMS or predictive emissions monitoring system (PEMS), it shall meet the requirements of §117.213(e) or (f) of this title.

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

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

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

(2) Units which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions.

(3) All testing shall be conducted while operating at the maximum rated capacity, or as near thereto as practicable. Compliance shall be determined by the average of three one-hour emission test runs, using the following test methods:

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

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

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

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

(E) American Society of Testing and Materials (ASTM) Method D1945-91 or ASTM Method D3588-93 for fuel composition; ASTM Method D1826-88 or ASTM Method D3588-91 for calorific value; or

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

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

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

(4) Test results shall be reported in the units of the applicable emission limits and averaging periods. If compliance testing is based on 40 CFR Part 60, Appendix A reference methods, the report must contain the information specified in §117.211(g) of this title (relating to Initial Demonstration of Compliance).

(5) For units equipped with CEMS or PEMS, the CEMS or PEMS shall be installed and operational before testing under this subsection. Verification of operational status shall, as a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(6) Initial compliance with the emission specifications of §117.475 of this title for units operating with CEMS or PEMS shall be demonstrated after monitor certification testing using the NO_x CEMS or PEMS.

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

(A) Retesting as specified in paragraphs (1) - (4) of this subsection is required within 60 days after any modification which could reasonably be expected to increase the NO_x emission rate.

(B) Retesting as specified in paragraphs (1) - (4) of this subsection may be conducted at the discretion of the owner or operator after any modification which could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation (FGR), and fuel-lean and conventional (fuel-rich) reburn.

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

(8) Testing shall be performed in accordance with the schedule specified in §117.534 of this title.

(f) Emission allowances.

(1) For sources which are subject to Chapter 101, Subchapter H, Division 3 of this title, the NO_x testing and monitoring data of subsections (a) - (e) of this section, together with the level of activity, as defined in §101.350 of this title (relating to Definitions), shall be used to establish the emission factor calculating actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(2) The emission factor in subsection (e)(7) of this section or paragraph (1) of this subsection is multiplied by the unit's level of activity to determine the unit's actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(g) Recordkeeping. The owner or operator of a unit subject to the emission limitations of §117.475 of this title 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) records of annual fuel usage;

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

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

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

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

(ii) pounds or tons per day;

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

(A) emissions measurements required by §117.478(b)(5) of this title (relating to Operating Requirements); and

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

(4) records of carbon monoxide measurements specified in §117.478(b)(5) of this title;

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

(6) records of the results of performance testing, including the testing conducted in accordance with subsection (e) of this section.

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

(i) Run time meters. The owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.473(a)(2)(E), (H), or (I) of this title shall record the operating time with an elapsed run time meter. Any run time meter installed on or after October 1, 2001 shall be non-resettable.

(j) Records of operation for testing and maintenance. The owner or operator of each stationary diesel or dual-fuel engine shall maintain the following records for at least five years and make them available upon request by authorized representatives of the executive director, EPA, or local air pollution control agencies having jurisdiction:

(1) date(s) of operation;

(2) start and end times of operation;

(3) identification of the engine; and

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

SUBCHAPTER E: ADMINISTRATIVE PROVISIONS

§§117.510, 117.520, 117.534, 117.570

STATUTORY AUTHORITY

The amendments are adopted 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 the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted 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 et seq.

§117.510. Compliance Schedule 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) Reasonably Available Control Technology (RACT). The owner or operator shall for all units, comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than November 15, 1999 (final compliance date), except as specified in subparagraph (D) of this paragraph, relating to oil firing, and paragraph (2) of this subsection, relating to emission specifications for attainment demonstration:

(A) conduct applicable continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) evaluations and quality assurance procedures as specified in §117.113 of this title (relating to Continuous Demonstration of Compliance) according to the following schedules:

(i) for equipment and software required under 40 Code of Federal Regulations (CFR) 75, no later than January 1, 1995 for units firing coal, and no later than July 1, 1995 for units firing natural gas or oil; and

(ii) for equipment and software not required under 40 CFR 75, no later than November 15, 1999;

(B) install all nitrogen oxides (NO_x) abatement equipment and implement all NO_x control techniques no later than November 15, 1999;

(C) submit to the executive director:

(i) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.111 of this title (relating to Initial Demonstration of Compliance); by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(ii) for units operating with CEMS or PEMS in accordance with §117.113 of this title, the results of:

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

(II) the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title;

(III) no later than:

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

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

(D) conduct applicable tests for initial demonstration of compliance with the NO_x emission limit for fuel oil firing, in accordance with §117.111(d)(2) of this title, and submit test results within 60 days after completion of such testing; and

(E) submit a final control plan for compliance in accordance with §117.115 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology), no later than November 15, 1999.

(2) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.106(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) the total number of units required to reduce emissions in order to comply with §117.106(a) of this title using direct compliance with the emission specifications, counting only units still required to reduce after May 11, 2000; or

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

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

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

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

(i) identification of enforceable emission limits which satisfy subparagraph (A) of this paragraph;

(ii) the information specified in §117.116 of this title (relating to Final Control Plans Procedures for Attainment Demonstration Emission Specifications) to comply with subparagraph (A) of this paragraph; and

(iii) any other revisions to the source's final control plan as a result of complying with subparagraph (A) of this paragraph;

(C) July 31, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap to comply with subparagraph (A) of this paragraph;

(D) May 1, 2005, comply with §117.106(a) of this title;

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

(i) a demonstration of compliance with §117.106(a) of this title;

(ii) the information specified in §117.116 of this title; and

(iii) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.106(a) of this title; and

(F) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap NO_x emission limit to comply with the emission specifications in §117.106(a) of this title.

(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) Reasonably available control technology (RACT). The owner or operator shall comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than March 31, 2001 (final compliance date), except as provided in subparagraph (D) of this paragraph, relating to oil firing, and paragraph (2) of this subsection, relating to emission specifications for attainment demonstration:

(A) conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.113 of this title no later than March 31, 2001;

(B) install all NO_x abatement equipment and implement all NO_x control techniques no later than March 31, 2001;

(C) submit to the executive director:

(i) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.111 of this title no later than March 31, 2001;

(ii) for units operating with CEMS or PEMS in accordance with §117.113 of this title, the results of:

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

(II) the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title;

(III) no later than:

(-a-) March 31, 2001 for units complying with the NO_x emission limit in pounds per hour on a block one-hour average;

(-b-) May 31, 2001 for units complying with the NO_x emission limit on a rolling 30-day average;

(D) conduct applicable tests for initial demonstration of compliance with the NO_x emission limit for fuel oil firing, in accordance with §117.111(d)(2) of this title, and submit test results within 60 days after completion of such testing; and

(E) submit a final control plan for compliance in accordance with §117.115 of this title, no later than March 31, 2001.

(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) the total number of units required to reduce emissions in order to comply with §117.106(b) of this title using direct compliance with the emission specifications, counting only units still required to reduce after May 11, 2000; or

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

(-a-) §117.108 of this title; or

(-b-) §117.570 of this title;

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

(I) identification of enforceable emission limits which satisfy clause (i) of this subparagraph;

(II) the information specified in §117.116 of this title to comply with clause (i) of this subparagraph; and

(III) any other revisions to the source's final control plan as a result of complying with clause (i) of this subparagraph;

(iii) July 31, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap to comply with clause (i) of this subparagraph;

(iv) May 1, 2005, comply with §117.106(b) of this title;

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

(I) a demonstration of compliance with §117.106(b) of this title;

(II) the information specified in §117.116 of this title; and

(III) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.106(b) of this title; and

(vi) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap NO_x emission limit to comply with the emission specifications in §117.106(b) of this title.

(B) The requirements of §117.510(b)(2)(A)(i) of this title may be modified as follows. Boilers which are to be retired and decommissioned before May 1, 2005 are not required to install controls by May 1, 2003 if the following conditions are met:

(i) the boiler is designated by the Public Utility Commission of Texas to be necessary to operate for reliability of the electric system;

(ii) the owner provides the executive director an enforceable written commitment by May 1, 2003 to retire and permanently decommission the boiler by May 1, 2005;

(iii) the utility boiler is retired and permanently decommissioned by May 1, 2005; and

(iv) by May 1, 2003, all remaining boilers (those not designated for retirement and decommissioning as specified in clauses (i) - (iii) of this subparagraph) within the electric utility system are controlled to achieve at least two-thirds of the NO_x emission reductions from units not being retired and decommissioned.

(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) Reasonably Available Control Technology. The owner or operator shall, for all units, comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than November 15, 1999 (final compliance date), except as specified in subparagraph (D) of this paragraph, relating to oil firing, and paragraph (2) of this subsection, relating to emission specifications for attainment demonstration:

(A) conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.113 of this title according to the following schedules:

(i) for equipment and software required under 40 CFR 75, no later than January 1, 1995 for units firing coal, and no later than July 1, 1995 for units firing natural gas or oil; and

(ii) for equipment and software not required under 40 CFR 75, no later than November 15, 1999;

(B) install all NO_x abatement equipment and implement all NO_x control techniques no later than November 15, 1999;

(C) submit to the executive director:

(i) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.111 of this title; by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(ii) for units operating with CEMS or PEMS in accordance with §117.113 of this title, the results of:

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

(II) the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title;

(III) no later than:

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

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

(D) conduct applicable tests for initial demonstration of compliance with the NO_x emission limit for fuel oil firing, in accordance with §117.111(d)(2) of this title, and submit test results within 60 days after completion of such testing; and

(E) submit a final control plan for compliance in accordance with §117.115 of this title, no later than November 15, 1999.

(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) March 31, 2005, install any totalizing fuel flow meters and emissions monitors required by §117.114 of this title, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.114 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit; and

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

(I) stack tests conducted in accordance with §117.111 of this title; or, as applicable,

(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) March 31, 2003, 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 §117.108 of this title; and

(II) March 31, 2004, demonstrate that at least 95% 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) March 31, 2007, demonstrate compliance with the system cap limit of §117.108 of this title.

(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 §117.111 of this title; or, as applicable,

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

(D) The owner or operator shall comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) as soon as practicable, but no later than the appropriate dates specified in that program.

(E) 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) Reasonably available control technology (RACT). The owner or operator shall for all units, comply with the requirements of Subchapter B, Division 3 of this chapter, except as specified in paragraph (2) (relating to lean-burn engines) and paragraph (3) of this subsection (relating to emission specifications for attainment demonstration) of this subsection, by November 15, 1999 (final compliance date) and submit to the executive director:

(A) for units operating without a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS), the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title (relating to Initial Demonstration of Compliance); by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(B) for units operating with CEMS or PEMS in accordance with §117.213 of this title (relating to Continuous Demonstration of Compliance), the results of:

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

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

(iii) no later than:

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

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

(C) a final control plan for compliance in accordance with §117.215 of this title (relating to Final Control Plan Procedures), no later than November 15, 1999; and

(D) the first semiannual report required by §117.219(d) or (e) of this title (relating to Notification, Recordkeeping, and Reporting Requirements), covering the period November 15, 1999 through December 31, 1999, no later than January 31, 2000; and

(2) Lean-burn engines. The owner or operator shall for each lean-burn, stationary, reciprocating internal combustion engine subject to §117.205(e) of this title (relating to Emission Specifications), comply with the requirements of Subchapter B, Division 3 of this chapter for those engines as soon as practicable, but no later than November 15, 2001 (final compliance date for lean-burn engines); and

(A) no later than November 15, 2001, submit a revised final control plan which contains:

(i) the information specified in §117.215 of this title as it applies to the lean-burn engines; and

(ii) any other revisions to the source's final control plan as a result of complying with the lean-burn engine emission specifications; and

(B) no later than January 31, 2002, submit the first semiannual report required by §117.219(e) of this title covering the period November 15, 2001 through December 31, 2001.

(3) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.206(a) of this title (relating to Emission Specifications for Attainment Demonstrations) as soon as practicable, but no later than:

(A) May 1, 2003, demonstrate that at least two-thirds of the NO_x emission reductions required by §117.206(a) of this title have been accomplished, as measured either by:

(i) the total number of units required to reduce emissions in order to comply with §117.206(a) of this title using direct compliance with the emission specifications, counting only units still required to reduce after May 11, 2000; or

(ii) the total amount of emissions reductions required to comply with §117.206(a) of this title using the alternative methods to comply, either:

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

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

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

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

(i) identification of enforceable emission limits which satisfy the conditions of subparagraph (A) of this paragraph;

(ii) for units operating without CEMS or PEMS or for units operating with CEMS or PEMS and complying with the NO_x emission limit on an hourly average, the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title;

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

(iv) the information specified in §117.216 of this title (relating to Final Control Plans Procedures for Attainment Demonstration Emission Specifications); and

(v) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.206(a) of this title;

(C) July 31, 2003, submit to the executive director:

(i) the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title, for units complying with the NO_x emission limit on a rolling 30-day average; and

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

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

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

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

(ii) the information specified in §117.216 of this title; and

(iii) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.206(a) of this title; and

(F) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title, if using the 30-day average source cap NO_x emission limit to comply with the emission specifications in §117.206(a) of this title.

(b) The owner or operator of each industrial, commercial, and institutional source in the Dallas/Fort Worth ozone nonattainment area shall comply with the requirements of Subchapter B, Division 3 of this chapter as soon as practicable, but no later than March 31, 2002 (final compliance date). The owner or operator shall:

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

(2) submit to the executive director:

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

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

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

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

(iii) no later than:

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

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

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

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

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

(1) Reasonably available control technology (RACT). The owner or operator shall, for all units, comply with the requirements of Subchapter B, Division 3 of this chapter, except as specified in paragraph (2) (relating to emission specifications for attainment demonstration), by November 15, 1999 (final compliance date) and:

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

(i) for major sources of NO_x which have units subject to emission specifications under this chapter, submit an initial control plan for all such units no later than April 1, 1994;

(ii) for major sources of NO_x which have no units subject to emission specifications under this chapter, submit an initial control plan for all such units no later than September 1, 1994; and

(iii) for major sources of NO_x subject to either subparagraph (A) or (B) of this paragraph, submit the information required by §117.209(c)(6), (7), and (9) of this title no later than September 1, 1994;

(B) install all NO_x abatement equipment and implement all NO_x control techniques no later than November 15, 1999;

(C) submit to the executive director:

(i) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title; by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

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

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

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

(III) no later than:

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

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

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

(iv) the first semiannual report required by §117.219(d) or (e) of this title, covering the period November 15, 1999, through December 31, 1999, no later than January 31, 2000.

(2) Emission specifications for attainment demonstration.

(A) The owner or operator shall comply with the requirements of §117.214 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) as soon as practicable, but no later than:

(i) March 31, 2005, install any totalizing fuel flow meters, run time meters, and emissions monitors required by §117.214 of this title, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.214 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit; and

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

(I) stack tests conducted in accordance with §117.211 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.

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

(i) no later than June 30, 2001, submit to the executive director the certification of level of activity, H_i, specified in §117.210 of this title (relating to System Cap) for EGFs which were in operation as of January 1, 1997;

(ii) no later than 60 days after the second consecutive third quarter of actual level of activity level data are available, submit to the executive director the certification of activity level, H_i, specified in §117.210 of this title for EGFs which were not in operation prior to January 1, 1997; and

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

(I) March 31, 2004, demonstrate compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2004, submit a demonstration of the NO_x emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2004, were not equipped with flue gas cleanup, shall form the April 1, 2004 - March 31, 2005 system cap limit of §117.210 of this title;

(II) March 31, 2005, demonstrate compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2005, submit a demonstration of the NO_x emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2005, were not equipped with flue gas cleanup, shall form the April 1, 2005 - March 31, 2006 system cap limit of §117.210 of this title;

(III) March 31, 2006, demonstrate compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2006, submit a demonstration of the NO_x emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2006, were not equipped with flue gas cleanup, shall form the April 1, 2006 - March 31, 2007 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.

(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 in accordance with §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 compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2004, submit a demonstration of the NO_x emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2004, were not equipped with flue gas cleanup, shall form the April 1, 2004 - March 31, 2005 system cap limit of §117.210 of this title;

(II) March 31, 2005, demonstrate compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2005, submit a demonstration of the NO_x emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2005, were not equipped with flue gas cleanup, shall form the April 1, 2005 - March 31, 2006 system cap limit of §117.210 of this title;

(III) March 31, 2006, demonstrate compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2006, submit a demonstration of the NO_x emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2006, were not equipped with flue gas cleanup, shall form the April 1, 2006 - March 31, 2007 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) For any units subject to §117.206(c) of this title for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph (2)(A) of this subsection, the owner or operator shall submit to the executive director as soon as practicable, but no later than March 31, 2007, the results of:

(i) stack tests conducted in accordance with §117.211 of this title; or, as applicable,

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

(E) 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 no later than March 31, 2005, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.479 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit;

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

(i) stack tests conducted in accordance with §117.479 of this title; or, as applicable,

(ii) the applicable continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (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 (relating to Continuous Demonstration of Compliance);

(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) stack tests conducted in accordance with §117.479 of this title; or, as applicable,

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

(D) 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 no later than March 31, 2005, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.479 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit;

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

(i) stack tests conducted in accordance with §117.479 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;

(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 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 Emission Specifications), §117.207 of this title (relating to Alternative Plant-wide Emission Specifications), §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), unless there are federal or state regulations or permits under the same commission account number which contain a condition or conditions precluding such use.

(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) 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 or 4 of this title and/or otherwise reduce emissions prior to the effective date of such rule change. For units using RCs in accordance with this section 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)

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

Where:

ΔE	=	the differential of emissions
LA	=	the maximum level of activity
HEROLD	=	the existing NO_x emission rate for the affected in lb per unit of activity
ERNE	=	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