The Texas Natural Resource Conservation Commission (TNRCC or commission) adopts amendments to §117.10, concerning Definitions; §§117.101, 117.103, 117.105, 117.106, 117.108, 117.111, 117.113, 117.116, 117.119, and 117.121, concerning Utility Electric Generation in Ozone Nonattainment Areas; §117.138, concerning System Cap; §§117.201, 117.203, 117.205 - 117.208, 117.211, 117.213, 117.216, 117.219, and 117.221, concerning Industrial, Commercial, and Institutional Sources in Ozone Nonattainment Areas; and §117.510 and §117.520, concerning Administrative Provisions. The commission also adopts new §117.114 and §117.214, concerning Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration; §117.210, concerning System Cap; and §117.534, concerning Compliance Schedule for Boilers, Process Heaters, and Stationary Engines at Minor Sources. The commission also adopts new §§117.471, 117.473, 117.475, 117.478, and 117.479 in Subchapter D, which are being added as a new Division 2, concerning Boilers, Process Heaters, and Stationary Engines at Minor Sources. Sections 117.10, 117.103, 117.105, 117.106, 117.108, 117.114, 117.116, 117.121, 117.201, 117.203, 117.205, 117.206, 117.208, 117.210, 117.213, 117.214, 117.216, 117.219, 117.221, 117.473, 117.475, 117.478, 117.479, 117.510, 117.520, and 117.534 are adopted *with changes* to the proposed text as published in the August 25, 2000, issue of the *Texas Register* (25 TexReg 8275). Sections 117.101, 117.111, 117.113, 117.119, 117.138, 117.207, 117.211, and 117.471 are adopted *without changes* and will not be republished.

The revisions to Chapter 117 and to the state implementation plan (SIP) require a wide variety of stationary sources of nitrogen oxides (NO_x) emissions in the Houston/Galveston (HGA) ozone nonattainment area to meet new emission specifications and other requirements in order to reduce NO_x emissions and ozone air pollution. The affected equipment types and processes include electric utility

boilers and stationary gas turbines; industrial, commercial, and institutional (ICI) boilers and stationary gas turbines; duct burners used in turbine exhaust ducts; process heaters and furnaces; stationary internal combustion (IC) engines; fluid catalytic cracking units (FCCUs), including catalyst regenerators and associated carbon monoxide (CO) boilers and furnaces; pulping liquor recovery furnaces; lime kilns; lightweight aggregate kilns; metallurgical heat treating furnaces and reheat furnaces; magnesium chloride fluidized bed dryers; incinerators, including enclosed control devices that combust or oxidize gases or vapors; and hazardous waste-fired boilers and industrial furnaces (BIF units).

The commission adopts these amendments to Chapter 117, concerning Control of Air Pollution from Nitrogen Compounds, and 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 (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. Another purpose of these amendments is to ensure that reasonably available control technology (RACT) requirements, as required by 42 USC, §7511a(f), are applied to major NO_x sources in HGA which are not subject to the previous NO_x RACT rules.

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 (42 USC, §§7401 et seq.), and therefore is required to attain the one-hour ozone standard of

0.12 parts 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 by 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 its 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 programs in particular resulted in changing deadlines and requirements. The first of these programs was 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 this study, and it has been concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that has impacted the SIP planning process is the revision to the national ozone standard. 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) that 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, that 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-99 ROP plan by December 31, 2000; to perform a mid-course review by May 1, 2004; and to perform modeling of mobile source emissions using the EPA mobile source emissions model (MOBILE6), to revise the on-road mobile source budget as needed, and to submit the revised budget within 24 months of the model's release. In addition, if a conformity analysis is to be performed between 12 months and 24 months after the MOBILE6 release, the state will revise the motor vehicle emissions budget (MVEB) so that the conformity analysis and the SIP MVEB are calculated on the same basis.

In order for the state to have an approvable attainment demonstration, EPA has 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 emission reduction requirements included as part of this SIP revision represent 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, have worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area have formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

This rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000 and planned to be submitted to the EPA by December 31, 2000.

The amount of NO_x reductions required for the area to attain the ozone NAAQS has been estimated by extensive use of sophisticated air quality grid modeling, which because of its scientific and statutory grounding, is the chief policy tool for designing emission reduction strategies. The FCAA, 42 USC, §7511a(c)(2), requires the use of photochemical grid modeling for ozone nonattainment areas designated serious, severe, or extreme. The modeling has been conducted with input from a technical oversight committee. Commission staff have continued to improve the air quality modeling technology and refine emission inventory data. Numerous emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources, on-road and non-road mobile sources, and area sources were analyzed in multiple iterations of modeling, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling and other analysis submitted for public hearing and comment concurrently with these rules show that close to the maximum NO_x reductions practicably achievable are necessary from each ozone control strategy in order for HGA to achieve the ozone NAAQS by 2007, including reductions from surrounding counties included in the HGA consolidated metropolitan statistical area (CMSA). Therefore, each strategy,

including the reductions required by this rulemaking, is crucial to meeting federal requirements for the HGA nonattainment area.

Additionally, reductions associated with the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies. At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever increasing number of air quality professionals have concluded that ozone is a regional problem requiring regional strategies in addition to local control programs. As nonattainment areas across the United States prepared attainment demonstration SIPs in response to the 1990 FCAA Amendments, several areas found that modeling attainment was made much more difficult, if not impossible, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The current SIP revision contains rules, enforceable commitments, photochemical modeling analyses, and calculation of the remaining NO_x reductions required to reach attainment (gap calculation) in support of the HGA ozone attainment demonstration. In addition, this SIP contains Post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contains 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.

The Houston nonattainment area will need to ultimately reduce NO_x more than 750 tpd to reach attainment with the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of point source NO_x rules 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 tons of NO_x per day 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. 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 this issue of the *Texas Register*, 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.

Figure 1: 30 TAC Chapter 117 - Preamble

POTENTIAL NO_X EMISSION REDUCTIONS BY POINT SOURCE CATEGORY

FOR HOUSTON/GALVESTON NONATTAINMENT AREA COUNTIES - Revised 12/6/00

Category	1997 Emissions (tpd)	% of Total Point	Chapter 117 NO_x RACT Reductions (%; tpd)	Tier I Reductions Combustion Modifications	Tier II Reductions Flue Gas Cleanup	Tier III Reductions = Tier I + II	Tier III ESAD* Rates lb/MMBtu
Utility Boilers	196.44	29.4	9%; 21 tpd	50%; 97.6 tpd	87%; 172 tpd	93%; 184 tpd	0.010 - 0.060
Turbines (+Duct Burners)	155.65	23.3	17%; 30 tpd	60%; 93.5 tpd	89%; 138 tpd	91%; 141 tpd	0.015 - 0.150
Heaters and Furnaces	110.12	16.5	0%; 0 tpd	50%; 54.9 tpd	84%; 92 tpd	88%; 97 tpd	0.010 - 0.036
IC Engines	86.37	12.9	30%; 29 tpd	50%; 43.5 tpd	86%; 74 tpd	91%; 75 tpd	0.045 - 0.133[1]
Industrial Boilers	85.98	12.9	10%; 9 tpd	40%; 34.3 tpd	87%; 75 tpd	92%; 79 tpd	0.010 - 0.089
Other	32.99	4.9	0%; 0 tpd	2%; 0.7 tpd	58%; 19 tpd	60%; 19 tpd	various
Overall Point Source	667.56	100.0	12%; 91 tpd	48%; 324 tpd	84%; 569 tpd	89%; 595 tpd	--

*ESAD = Emission specifications for attainment demonstration

[1](0.17 - 0.50 g/hp-hr)

Another table in the Tables and Graphics section of this issue of the *Texas Register*, 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 proposed Chapter 117 rules.

Figure 2: 30 TAC Chapter 117 - Preamble

SUBCATEGORIES - POINT SOURCE POTENTIAL NO_x EMISSION REDUCTIONS FOR HOUSTON/GALVESTON NONATTAINMENT AREA COUNTIES - Revised 12/6/00

Category	1997 Emissions (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	95%; 74.33 tpd	0.010 lb/MMBtu
Gas Tangential-fired	13.34		5	30%; 4.00 tpd	90%; 12.01 tpd	93%; 12.46 tpd	0.010 lb/MMBtu
Coal Wall-fired	56.92		2	45%; 25.61 tpd	85%; 48.38 tpd	92%; 52.39 tpd	0.030 lb/MMBtu
Coal Tangential-fired	47.78		2	60%; 28.67 tpd	85%; 40.61 tpd	92%; 44.08 tpd	0.030 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	93%; 184 tpd	
Turbines and Duct Burners							
Electric Generation	138.58		78	62%; 86.22 tpd	90%; 125.15 tpd	92%;127.78 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	0.30		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 (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	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Other Diesel	0.20		10	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
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	50%; 43.51 tpd	86%; 73.88 tpd	88%; 75.63 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 (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	

The tables show that emission reductions approaching the tpd rate required by the attainment demonstration necessitate further reductions from essentially all categories, including electric utility boilers and stationary gas turbines; ICI boilers and stationary gas turbines; duct burners used in turbine exhaust ducts; process heaters and furnaces; stationary IC engines; FCCUs (including catalyst regenerators and CO boilers and furnaces); pulping liquor recovery furnaces; lime kilns; lightweight aggregate kilns; heat treating furnaces; reheat furnaces; magnesium chloride fluidized bed dryers; incinerators (including enclosed control devices that combust or oxidize gases or vapors); and BIF units.

To develop the information in this table and analyze the reductions obtainable by potential NO_x emission rate specifications (in pound per million British thermal units (lb/MMBtu) heat input, gram per horsepower-hour (g/hp-hr), etc.), commission staff gathered the emission rate factors used to calculate June - August 1997 emissions for the major NO_x sources in HGA. In January 2000, commission staff sent out a rate data survey to major NO_x sources in HGA and made follow-up requests in an attempt to fill in missing rate data. In situations where the major NO_x sources did not or could not provide rate data, commission staff estimated the missing rate data from available data for similar equipment. Commission staff also conducted a quality assurance analysis of the 1997 emissions inventory in order to correctly classify equipment into the various categories shown in the table. The information was compiled in a spreadsheet, allowing reductions from a rate limit applied to an equipment category to be calculated either as a number of tons of NO_x per day reduced or as a percentage reduction from the category.

The commission staff then evaluated the emission reductions that would be achieved by applying various attainment demonstration emission rate limits to the equipment categories. Because some NO_x emission sources simply cannot be reasonably controlled (for example, flares), it is necessary that the larger emission categories, especially electric utility boilers, stationary gas turbines, engines, and ICI boilers, achieve more than a 90% reduction in order for the overall emission reductions from NO_x point sources to come as close as possible to the 90% target that modeling has shown is necessary for HGA to be able to demonstrate attainment of the ozone NAAQS. Through an iterative process, the commission staff developed emission specifications for the major NO_x point source categories which approach the maximum practicable emission reductions for these sources and, while technically challenging to meet, are a necessary and essential component of the HGA Attainment Demonstration SIP, adopted concurrently by the commission.

SECTION BY SECTION DISCUSSION

The primary purpose of the revisions to Chapter 117 and to the SIP is to establish new emission specifications for the ozone attainment demonstrations. However, another purpose of these revisions is to ensure that RACT requirements are applied to major NO_x sources in HGA, as required by 42 USC, §7511a(f). The current NO_x RACT limits in §117.105, concerning Emission Specifications for Reasonably Available Control Technology (RACT), and §117.205, concerning Emission Specifications for Reasonably Available Control Technology (RACT), apply to certain boilers, process heaters, stationary IC engines, and stationary gas turbines. The amendments establish emission specifications for boilers; process heaters and furnaces; stationary IC engines and stationary gas turbines; duct burners used in turbine exhaust ducts; FCCUs (including catalyst regenerators and associated CO boilers and

furnaces); pulping liquor recovery furnaces; lime kilns; lightweight aggregate kilns; heat treating furnaces; reheat furnaces; magnesium chloride fluidized bed dryers; incinerators (including enclosed control devices that combust or oxidize gases or vapors); and BIF units which are currently exempt from the NO_x RACT limits in §117.105 and §117.205. While the emission specifications for attainment demonstration (ESADs) are more stringent than RACT, these emission specifications will nevertheless also fulfill the NO_x RACT requirements of 42 USC, §7511a(f), for major sources in HGA which are not subject to the previous NO_x RACT rules.

The amendments to §117.10, concerning Definitions, revise the definition of "auxiliary steam boiler" to clarify that 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.

Although the term "incinerator" is defined in §101.1 to refer to units which burn wastes for the primary purpose of reducing volume and weight, this term historically has also been used to refer to enclosed control devices that combust or oxidize gases or vapors, particularly in Chapter 115. The ESADs for incinerators apply to both types of units. Therefore, the amendments to §117.10 add a definition of "incinerator" to clarify that for the purposes of Chapter 117, the term "incinerator" includes both enclosed control devices that combust or oxidize gases or vapors, and incinerators as defined in §101.1. The new definition is not a substantive change from how the commission intended the term to be used in Chapter 117, and its inclusion in the adopted rule will provide clarity. Subsequent definitions in §117.10 were renumbered to accommodate the addition of the new definition of “incinerator.”

The amendments to §117.10 also revise the definition of "low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit" by changing the order of "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the title of this division. The amendments to §117.10 add a definition of "electric generating facility (EGF)" which is consistent with the corresponding definition in §117.330(12), concerning Definitions, and also add definitions of “heat treat furnace” and “reheat furnace” which are needed to clarify the units to which the new requirements apply. Subsequent definitions in §117.10 were renumbered to accommodate the new definitions.

In addition, the amendments to §117.10 revise the definitions of "boiler or steam generator," "electric power generating system," "industrial boiler or steam generator," "large DFW system," "process heater," "small DFW system," "unit," and "utility boiler or steam generator" by deleting the superfluous term "steam generator" since a steam generator is simply a boiler and is already addressed by this term in the Chapter 117 rules.

The amendments to §117.10 also revise the definition of "unit" to broaden its applicability. Currently, this definition includes boilers, process heaters, stationary gas turbines, and stationary IC engines. Because the emission reductions approaching the tpd emission rate required by the attainment demonstration necessitate further reductions from essentially all categories, the amendments broaden the applicability of the definition of unit to include any other stationary source of NO_x at a major source.

In addition, the amendments to §117.10 revise the renumbered §117.10(36) to define "predictive emissions monitoring system (PEMS)" rather than "predictive emission monitoring system (PEMS)" for consistency with the definition of "continuous emissions monitoring system (CEMS)" in the renumbered §117.10(9) and the usage of these terms in the rules. Finally, the amendments to §117.10 revise the definitions of "large DFW system" and "small DFW system" to improve the readability of these definitions.

The amendments to §117.101, concerning Applicability, delete the superfluous term "steam generator" since a steam generator is simply a boiler and is already addressed by this term in the Chapter 117 rules, and renumber the paragraphs accordingly. The amendments to §117.101 also revise a reference in the renumbered §117.101(3) from "gas turbines" to "stationary gas turbines" for consistency with the definition of this term in the renumbered §117.10(41), and update a reference to the definition of "electric power generating system" in the renumbered §117.10(12).

The amendments to §117.103, concerning Exemptions, revise §117.103(a) to specify the exemptions from the RACT requirements. The units which are exempt from RACT are those currently exempt under this subsection from the entire division. However, the revised language states that these units are exempt from the specific sections for which these units would otherwise be subject, rather than from the entire division. Although this would appear to narrow the scope of the exemptions, it is not expected to add any additional requirements because other sections in this division generally do not apply to these units (except as specified in §117.113, concerning Continuous Demonstration of Compliance). In addition, the amendments to §117.103 revise §117.103(a)(2) to delete the superfluous term "steam

generator" since a steam generator is simply a boiler and is already addressed by this term in the Chapter 117 rules.

A new §117.103(b) specifies that stationary gas turbines and engines which are used solely to power other engines or gas turbines during start-ups are exempt from the attainment demonstration requirements of §117.106, concerning Emission Specifications for Attainment Demonstrations; §117.108, concerning System Cap; and §117.113, except as may be specified in §117.113(i). The attainment demonstration exemptions do not include the RACT exemptions for new units placed into service after November 15, 1992; utility boilers, and auxiliary steam boilers with an annual heat input less than or equal to $2.2(10^{11})$ Btu per year; and stationary gas turbines and engines which operate less than 850 hours per year, because emission reductions from essentially all categories are necessary to approach the tpd emission rate required by the attainment demonstration. Finally, subsections are given titles (catchlines) to identify the topics covered.

Because the attainment demonstration exemptions do not include the RACT exemptions for new units placed into service after November 15, 1992, the title of Subchapter B, concerning Combustion at Existing Major Sources, has been changed to Combustion at Major Sources.

The existing §117.103(b) includes an exemption from the oil-fired RACT emission limits during emergency conditions which necessitate oil firing. The amendments to §117.103 renumber this exemption as §117.103(c), break it into paragraphs to make the text more readable, and revise it to include exemption from the emission specifications of §117.106, concerning Emission Specifications for

Attainment Demonstrations, and §117.108. This revision is adopted in order to address concerns regarding times of natural gas curtailments, which are typically a cold weather issue. Although the system cap is less likely to be exceeded under natural gas curtailment conditions because the 30-day average winter peak electric demand is not as great as the summer 30-day peak demand, extensive oil firing due to an emergency condition could cause exceedances of the cap. The broadening of the exemption in the renumbered §117.103(c) will address this concern.

The new §117.103(d) exempts from the requirements of Chapter 117 all combustion units which would meet the requirements of a standard permit currently being developed for electricity-generating combustion units rated at no more than ten megawatts (MW) in capacity and which emit no more than 0.015 lb NO_x/MMBtu heat input. The commission is adding this exemption to facilitate the installation of small (ten MW or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid. This exemption is intended to provide an incentive for installation and use of new clean energy-producing technology. The emission limit of the proposed standard permit is consistent with the adopted ESAD of 0.015 lb NO_x/MMBtu heat input.

The amendments to §117.105 revise §117.105(a) - (d) and (h) to delete the superfluous term "steam generator" since a steam generator is simply a boiler and is already addressed by this term in the Chapter 117 rules. The amendments to §117.105(h) also add equivalent alternate CO standards based on heat input to simplify compliance tracking for monitoring systems which are based on carbon dioxide as the diluent.

In addition, the amendments to §117.105 correct the title of §117.510 in §117.105(k)(2). Finally, the amendments to §117.105 add a new §117.105(l) which specifies that after the applicable attainment demonstration SIP compliance date(s), the RACT emission specifications will no longer apply to equipment for which §117.106, concerning Emission Specifications for Attainment Demonstrations, has established more stringent emission specifications. This will avoid any potential conflicts of RACT limits and the new more stringent attainment demonstration emission specifications. For purposes of §117.105(l), the RACT emission specifications of §117.105 remain in effect until the emissions allocation for a unit under the HGA mass emissions cap are equal or less than the allocation that would be calculated using the RACT emission specifications of §117.105.

The amendments to §117.106 specify new NO_x emission specifications for electric utility boilers located in HGA. The adopted specifications are essential components of and consistent with the HGA Attainment Demonstration SIP, adopted concurrently by the commission. The emission specifications and ozone attainment demonstration SIP are required by 42 USC, §7410 and §7511a, which require states to submit SIPs to the EPA which contain enforceable measures to achieve the NAAQS. The process by which the emission specifications were developed is described in the BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES section of this preamble.

The amendments to §117.106(a) and (b) abbreviate the term "pound per million Btu," correct a typographical error in "Beaumont/Port Arthur," and reorganize the syntax of these sentences for consistency with the new §117.106(c).

The NO_x emission specifications for electric utility boilers, auxiliary steam boilers, and stationary gas turbines located in HGA are being added as a new §117.106(c) and are based on a daily rate and 30-day average. The 24-hour emission limit in both NO_x RACT and these rules is designed to limit the amount of NO_x allowed in a 24-hour period, in order to control peak ozone, which forms on a daily cycle. The emission specifications of §117.106(c) also apply as specified in §117.108 and in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, concerning Mass Emissions Cap and Trade Program, adopted concurrently in this issue of the *Texas Register*.

The emission specifications of §117.106(c) for electric utility boilers, auxiliary steam boilers, and stationary gas turbines in HGA are part of a larger set of emission reduction measures for the HGA Attainment Demonstration SIP. The larger context of development of the NO_x emission specification for electric utility boilers, auxiliary steam boilers, and stationary gas turbines in HGA is discussed in the BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES section of this preamble. The emission specifications of 0.010 lb NO_x/MMBtu heat input for gas-fired boilers; 0.030 lb NO_x/MMBtu heat input for oil- or coal-fired, tangential-fired boilers; 0.030 lb NO_x/MMBtu heat input for oil- or coal-fired, wall-fired boilers; 0.010 lb NO_x/MMBtu heat input for auxiliary boilers with a maximum rated capacity equal to or greater than 100 MMBtu/hr; 0.015 lb NO_x/MMBtu heat input for auxiliary boilers with a maximum rated capacity equal to or greater than 40 MMBtu/hr but less than 100 MMBtu/hr; 0.036 lb NO_x per MMBtu heat input (or alternatively, 30 parts per million by volume (ppmv) NO_x, at 3.0% oxygen (O_2), dry basis) for auxiliary boilers with a maximum rated capacity less 40 MMBtu/hr; and alternatively, 0.060 lb/MMBtu for units with an annual capacity factor of 0.0383 or less will achieve a 93% emission reduction and generate an

estimated 183.52 tpd NO_x reductions from HGA electric utility boiler emissions. The 93% NO_x reduction is expected to necessitate combustion controls and flue gas cleanup on many of the boilers at electric utilities in the HGA area.

A new §117.106(c)(4) provides low annual capacity factor units with an alternative to the emission specifications in §117.106(c)(1) - (3). The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units 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.

The emission specification of 0.015 lb NO_x/MMBtu heat input for stationary gas turbines (or 0.15 lb NO_x per MMBtu heat input for existing stationary gas turbines rated at less than 1.0 MW) will achieve a 91% emission reduction in conjunction with the emission specification of 0.015 lb NO_x per MMBtu heat input for stationary gas turbines and duct burners in §117.206(c)(10) and (11), respectively, concerning Emission Specifications for Attainment Demonstrations, and generate an estimated total of 140.92 tpd NO_x reductions from these units in HGA, based on the 1997 emissions inventory. The 91% NO_x reduction is expected to necessitate combustion controls and flue gas cleanup on many of the stationary gas turbines in the HGA area.

The existing §117.106(c) and (d) are being renumbered as §117.106(d) and (e). The amendments to the renumbered §117.106(d) make applicable in HGA the ammonia and CO emission limits in order to address pollutants which may increase as an incidental result of compliance with the NO_x emission specifications. The CO and ammonia limits are the limits which are applicable in Beaumont/Port

Arthur (BPA) and Dallas/Fort Worth (DFW). This ammonia limit of ten ppmv is lower than the existing RACT limit of §117.105(j). The lower ammonia limit is supported by information from selective catalytic reduction (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*, issued by the Northeast States for Coordinated Air Use Management (NESCAUM) and the Mid-Atlantic Regional Air Management Association (MARAMA) (June 1998) (will be referred to as NESCAUM). It is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The commission excluded these related pollutant limits from the attainment demonstration SIP in order to simplify the approval process for alternative emission specification under §107.121. This step will eliminate the need for case-specific SIP revisions by the EPA to complete the approval of an alternate CO or ammonia limit.

The amendments to the renumbered §117.106(d)(1) add equivalent alternate CO standards based on heat input to simplify compliance tracking for monitoring systems which are based on carbon dioxide as the diluent.

The amendments to the renumbered §117.106(e) specify that in HGA, the utility owner or operator may not use the trading option in §117.570. This is necessary to ensure that any trading that occurs is done under the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, adopted concurrently in this issue of the *Texas Register*. The owners and operators of the equipment addressed by these Chapter 117 revisions will be required to use the compliance flexibility provided by the

Chapter 101 mass emissions cap and trade program, which will allow compliance to be established through the use of surplus reductions created from other sources. Units which meet the definition of EGF are required to use both the system cap specified in §117.108 and the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 to comply with the NO_x emission specifications of §117.106(c).

Section §117.106(e) also does not allow the use of §117.107 as an alternative for complying with the §117.106 emission specifications for attainment demonstrations. Section 117.107 emission averaging does not address the effects of activity level, and may not produce the intended reductions that would be achieved with direct compliance by all units or flexible compliance with an emission cap. Under §117.107, higher emissions will result if units selected for less control are subsequently operated more, or if units selected for more control are subsequently operated less. The §117.106 emission specifications will necessitate installation of flue gas cleanup emission controls on a number of units. As a result, these units are likely to have higher operating costs than units operating with only combustion controls, creating an economic incentive to operate the best-controlled units less and to produce greater emissions.

The amendments to §117.108 require the owner or operator of each EGF in HGA to comply with the daily and 30-day system cap emission limitations of the existing system cap. The amendments to §117.108 also revise §117.108(a) - (i) and (k) by replacing references to "utility boiler" with the term "EGF." In addition, the amendments to §117.108 revise §117.108(b) by updating the reference to the definition of "electric power generating system" in the renumbered §117.10(12).

The amendments to §117.108 also revise §117.108(e)(4) to replace a reference to testing in a non-existent rule with a reference to the maximum block one-hour emission rate as measured by the 30-day test. In addition, the amendments to §117.108 revise §117.108(f) by correcting the title in the reference to §117.119, concerning Notification, Recordkeeping, and Reporting Requirements.

Finally, the amendments to §117.108 revise §117.108(i), which specifies that an EGF which is permanently retired or decommissioned and rendered inoperable may be included in the source cap emission limit, to state that in HGA the permanent shutdown must have occurred after January 1, 2000. Because §117.108(c)(1) specifies 1997, 1998, and 1999 for calculating the emissions cap, it is necessary for the shutdown to occur after this period.

Currently, EGFs in DFW may comply with §117.106 through compliance with the daily and 30-day system cap available under §117.108. The commission solicited comments concerning the possibility of adding flexibility for these EGFs by allowing trading between different electric power generating systems in DFW in order to meet the system cap of §117.108. Any such flexibility would necessitate separate rulemaking to establish the mechanism for trading between different electric power generating systems in DFW. Comments received regarding this issue are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

The amendments to §117.111, concerning Initial Demonstration of Compliance, correct the sentence structure of §117.111(a) by changing "be tested" to "test the units." The amendments to §117.111 also

correct the title of §117.510 in §117.111(a)(3), and revise §117.111(d)(3) by replacing the term "utility boilers" with "EGFs" for consistency with the corresponding changes to §117.108.

The amendments to §117.113, concerning Continuous Demonstration of Compliance, revise a reference in §117.113(f)(2)(A)(ii) from "United States Environmental Protection Agency" to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions.

The amendments to §117.113 also revise the catchline in §117.113(g) to clarify that these subsections apply to the NO_x RACT emission specifications of §117.105, and revise references in §117.113(g)(1) and (2) from "gas turbine" to "stationary gas turbine" for consistency with the definition of this term in §117.10(41).

In addition, the amendments to §117.113 add a new §117.113(h)(2) which specifies the totalizing fuel flow meter requirements for units at major NO_x sources in HGA which are subject to §117.106. All units which are listed in §117.101 will be subject to the totalizing fuel flow meter requirements because knowledge of the fuel usage is critical in determining the emission allocations for the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, adopted concurrently in this issue of the *Texas Register*. The existing §117.113(h)(1) - (3) is being renumbered as §117.113(h)(1)(A) - (C) to accommodate the new §117.113(h)(2).

The amendments to §117.113 also revise §117.113(i) to reflect the addition of the new §117.103(b). This revision will ensure that stationary gas turbines and engines which were required to install run time meters under the existing RACT requirements will continue to utilize those existing run time meters.

In addition, the amendments to §117.113 also revise §117.113(k) (being renumbered as §117.113(k)(1)) to specify that this subparagraph only applies to units in BPA or DFW, or to units in HGA which are subject to the NO_x RACT emission specifications of §117.105. A new §117.113(k)(2) specifies that for units in HGA which are subject to the ESADs of §117.106(c), the methods required in §117.113 and §117.114 shall be used in conjunction with the requirements of Chapter 101, Subchapter H, Division 3 to determine compliance. The new §117.113(k)(2) further specifies that for enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission specifications.

Finally, the amendments to the catchlines in §117.113(l) clarify that this subsection applies to the NO_x RACT emission specifications of §117.105.

The new §117.114 applies to units in HGA which are subject to the ESADs of §117.106(c) and specifies monitoring and testing requirements. The new §117.114(a) requires monitoring for NO_x, CO, and fuel flow as specified in §117.113(a) - (f) and (g). The new §117.114(b) requires testing of each unit which is subject to the emission specifications of §117.106(c). The testing requirements are consistent with the testing previously required of these units for NO_x RACT under §117.111.

Regarding emission allowances for the Chapter 101 mass emissions cap and trade program, §117.114(c) specifies that the NO_x testing and monitoring data specified in §117.114(a) and (b), together with the level of activity, as defined in §101.350, concerning Definitions, are used to establish the emission factor for the mass emissions cap and trade program. For units without CEMS or PEMS, retesting is required after any modifications which could increase the NO_x emission rate, but is optional after any modifications which could 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. The NO_x emission rate determined by the retesting establishes a new emission factor which must be used instead of the previously determined emission factor for the Chapter 101 mass emissions cap and trade program.

The amendments to §117.116, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, revise "units" to "utility boilers" in §117.216(a)(2) because the requirements of this section only apply to utility boilers. In addition, the amendments to §117.116 correct a title which is referenced in §117.116(c).

The amendments to §117.119 revise a reference in §117.119(a) from "Unites States Environmental Protection Agency" (which should have been "United States Environmental Protection Agency") to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions; and correct the reference in §117.119(a) to §101.11 to reflect the recent title change of this section from “Exemptions from Rules and Regulations” to “Demonstrations.” (See the July 14, 2000 issue of the *Texas Register*

(25 TexReg 6727).) The amendments to §117.110 also revise a reference in §117.119(d)(1)(A) from "gas turbines" to "stationary gas turbines" for consistency with the definition of this term in §117.10(41).

The amendments to §117.121, concerning Alternative Case Specific Specifications, update a reference to the existing §117.106(c) which is being renumbered as §117.106(d) and revise a reference from "United States Environmental Protection Agency" to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions. The amendments to §117.121(a) also add a reference to §117.106(d).

The amendments to §117.138, concerning System Cap, revise §117.138(b) to update a reference to the renumbered §117.10(12).

The amendments to §117.201, concerning Applicability, generalize the applicability by deleting the references to size cutoffs and adding the following to the list of units which are subject to this division: FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents); pulping liquor recovery furnaces; lime kilns; lightweight aggregate kilns; heat treating furnaces; reheat furnaces; magnesium chloride fluidized bed dryers; incinerators (including enclosed control devices that combust or oxidize gases or vapors); 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); and duct burners used in turbine exhaust ducts. It is necessary to generalize the applicability since the HGA Attainment Demonstration SIP rules include units which are presently excluded from §117.201. These changes do

not broaden the scope of the existing rules in BPA or HGA due to corresponding exemptions already in, or being added to, §117.203, concerning Exemptions, and §117.205(h) which are described later in this preamble. Finally, the amendments to §117.201 revise §117.201(1) by changing the order of "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the title of this division. Units used to produce steam for the purpose of generating electricity, but which are not owned or operated by a municipality or Public Utility Commission of Texas (PUCT) regulated utility, are included in the applicability of §117.201, rather than §117.101.

The amendments to §117.203 move the existing exemptions into a new subsection (a) and add a new exemption for heat treating furnaces and reheat furnaces as new §117.203(a)(3), with an expiration of this exemption in HGA for units rated at 20 MMBtu/hr or greater after the appropriate compliance date(s) for §117.206(c) specified in §117.520, concerning Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources in Ozone Nonattainment Areas. The expiration of this exemption in HGA for certain units is necessary for consistency with the amendments to §117.206(c)(14), which establishes emission specifications for these units in HGA.

In addition, the exemption in the existing §117.203(3) for electric utility power generating boilers was deleted. Although this change would appear to narrow the scope of the exemptions, it is not expected to add any additional requirements to these units in BPA and DFW because other sections in this division do not apply to these units. The requirements for units in HGA which are not subject to §117.106 will parallel the requirements of §117.206.

Further, the amendments to the renumbered §117.203(a)(4) and (5) specify that the exemptions for incinerators (including enclosed control devices that combust or oxidize gases or vapors), pulping liquor recovery furnaces, dryers, kilns, and ovens in HGA no longer apply after the appropriate compliance date(s) for §117.206 specified in §117.520. The amendments to the renumbered §117.203(a)(4) and (5) are necessary for consistency with §117.206(c)(12) - (16), which establish emission specifications for certain units in these categories in HGA.

The amendments to §117.203 also add a new §117.203(a)(9) which exempts boilers and process heaters with a maximum rated capacity of 2.0 MMBtu/hr or less. This exemption level is being adopted because units with a maximum rated capacity of 2.0 MMBtu/hr or less are already regulated under Subchapter D, Division 1, concerning Water Heaters, Small Boilers, and Process Heaters.

In addition, the amendments to §117.203 add a new §117.203(a)(10) which exempts diesel-fired stationary IC engines. It should be noted that §117.203(a)(6)(A) exempts stationary gas turbines and engines which are used in research and testing, or used for purposes of performance verification and testing, or used solely to power other engines or gas turbines during start-ups, or operated exclusively for firefighting and/or flood control, or used in response to and during the existence of any officially declared disaster or state of emergency, or used directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals, or used as chemical processing gas turbines. However, in the future, the commission may pursue emission reductions from these currently-exempt engines in HGA if additional reductions are determined to be necessary to reach attainment with the ozone NAAQS.

The amendments to §117.203 also add a new §117.203(b) which specifies that the exemptions in §117.203(a)(1), (2), (6)(B), (7), and (8)(A) no longer apply in HGA after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520. The expiration of these exemptions in HGA for certain units is necessary for consistency with §117.206(c), which establishes emission specifications for these units in HGA.

The new §117.203(c) exempts from the requirements of Chapter 117 all combustion units which would meet the requirements of a standard permit currently being developed for electricity-generating combustion units rated at no more than ten MW in capacity and which emit no more than 0.015 lb NO_x/MMBtu heat input. The commission is adding this exemption to facilitate the installation of small (ten MW or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid. This exemption is intended to provide an incentive for installation and use of new clean energy-producing technology. The emission limit of the proposed standard permit is consistent with the adopted ESAD of 0.015 lb NO_x/MMBtu heat input.

The amendments to §117.205 revise §117.205(b)(6) to include an equation for calculating an emission limitation for each rolling 30-day period for cases when gas fired boilers or process heaters at times also fire gaseous fuel which contain more than 50% hydrogen by volume. The equation uses a time weighted average to incorporate the two emission limits, from combusting two types of gaseous fuels, into one emission limitation for each rolling 30-day average. This amendment is based on a rule interpretation (Code Number R7-205.001) made by the agency's Air Rule Interpretation Team.

The amendments to §117.205 also revise §117.205(b)(7) by changing references from "continuous emission monitors" to "continuous emissions monitoring system" and from "predictive emission monitors" to "predictive emissions monitoring system" for consistency with the definitions of these terms in §117.10(9) and (36), respectively.

In addition, the amendments to §117.205 revise §117.205(c) to allow stationary gas turbines equipped with CEMS or PEMS for CO to meet the CO limit on a rolling 24-hour average, rather than on a one-hour average. This revision is consistent with the corresponding CO limit for boilers and process heaters in §117.205(f).

The amendments to §117.205 also revise §117.205(h)(1) by changing the order of "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the title of this division.

Additionally, the amendments to §117.205 revise the language for FCCUs and duct burners in §117.205(h)(4) and (5) for consistency with the corresponding language in §117.201(4) and (6). The amendments to §117.205(h) also add new paragraphs (8) - (10) for new units placed into service after November 15, 1992; stationary gas turbines and engines which are demonstrated to operate less than 850 hours per year (based on a rolling 12-month average); and stationary IC engines with a horsepower (hp) rating of less than 150 hp and 300 hp in HGA and BPA, respectively.

Finally, the amendments to §117.205 add a new §117.205(i) which specifies that after the applicable attainment demonstration SIP compliance date, the RACT emission specifications will no longer apply to equipment for which §117.206 has established a more stringent emission specification. This will avoid any potential conflicts of RACT limits and the new more stringent ESADs. For purposes of §117.205(i), the RACT emission specifications of §117.205 remain in effect until the emissions allocation for a unit under the HGA mass emissions cap are equal or less than the allocation that would be calculated using the RACT emission specifications of §117.205.

The amendments to §117.206(a) and (b) revise references to subsections (d) and (e), which should have been (e) and (f), to subsections (f) and (g) to accommodate the new §117.206(c) described in the following paragraph. In addition, the amendments to §117.206(b)(2) abbreviate the terms "horsepower" and "carbon monoxide."

The amendments to §117.206 add a new §117.206(c) which establishes NO_x emission specifications for boilers, process heaters, stationary IC engines, stationary gas turbines, FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents), BIF units, duct burners used in turbine exhaust ducts, pulping liquor recovery furnaces, lime kilns, lightweight aggregate kilns, heat treating furnaces, reheat furnaces, magnesium chloride fluidized bed dryers, and incinerators (including enclosed control devices that combust or oxidize gases or vapors) at major sources of NO_x in HGA. For units in HGA, the emission specifications in the new §117.206(c) will be used in the new Chapter 101, Subchapter H, Division 3, to establish emission allocations and shall be the lower of any applicable permit limit or the emission specifications described in the following paragraphs.

The amendments are essential components of and consistent with the HGA Attainment Demonstration SIP, adopted concurrently by the commission. The adopted emission specifications and ozone attainment demonstration SIP are required by 42 USC, §7410 and §7511a, which require states to submit SIPs to the EPA which contain enforceable measures to achieve the NAAQS. The amendments to §117.206 also update cross-references and renumber subsequent subsections to accommodate the new emission specifications within the section. The process by which the emission specifications were developed is described in the BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES and the *TECHNICAL FEASIBILITY* portion of the ANALYSIS OF TESTIMONY of this preamble.

The emission specifications in §117.206(c)(1) of 0.010 lb NO_x per MMBtu heat input for gas-fired boilers with a maximum rated capacity equal to or greater than 100 MMBtu/hr; 0.015 lb NO_x per MMBtu heat input for gas-fired boilers with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr; and 0.036 lb NO_x per MMBtu heat input (or alternatively, 30 ppmv NO_x, at 3.0% O_2, dry basis) for gas-fired boilers with a maximum rated capacity less 40 MMBtu/hr will achieve a 92% NO_x emission reduction from ICI boilers and generate an estimated 57.26 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification in §117.206(c)(2) of 13 ppmv NO_x (at 0.0% O_2, dry basis) for FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents) will achieve a 90% NO_x emission reduction and generate an estimated 13.44 tpd NO_x reductions in HGA, based on the 1997 emissions inventory. Alternative emission specifications for FCCUs include a 90% NO_x reduction of the exhaust

concentration used to calculate the June - August 1997 daily NO_x emissions; or for units which did not use CEMS or PEMS to determine the June - August 1997 exhaust concentration, a 90% NO_x reduction of the exhaust concentration in a third quarter 2001 baseline established by installation and certification of a NO_x CEMS or PEMS no later than June 30, 2001.

The emission specification in §117.206(c)(3) is 0.015 lb NO_x per MMBtu heat input for BIF units with a maximum rated capacity equal to or greater than 100 MMBtu/hr, and 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 for BIF units with a maximum rated capacity less than 100 MMBtu/hr. This will achieve an 80% NO_x emission reduction and generate an estimated 9.78 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification in §117.206(c)(4) of 0.057 lb NO_x per MMBtu heat input for coke-fired boilers will achieve a 90% NO_x emission reduction and generate an estimated 10.44 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification in §117.206(c)(5) of 0.046 lb NO_x per MMBtu heat input for wood fuel-fired boilers will achieve a 78% NO_x emission reduction and generate an estimated 0.79 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification in §117.206(c)(6) of 0.089 lb NO_x per MMBtu heat input for rice hull-fired boilers will achieve a 90% NO_x emission reduction and generate an estimated 0.46 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification in §117.206(c)(7) of 2.0 lb NO_x per 1,000 gallons of oil burned for oil-fired boilers will achieve a 90% NO_x emission reduction and generate an estimated 0.13 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specifications in §117.206(c)(8) of 0.010 lb NO_x per MMBtu heat input for process heaters with a maximum rated capacity equal to or greater than 100 MMBtu/hr; 0.015 lb NO_x per MMBtu heat input for process heaters with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr; and 0.036 lb NO_x per MMBtu heat input (or alternatively, 30 ppmv NO_x, at 3.0% O_2, dry basis) for process heaters with a maximum rated capacity less 40 MMBtu/hr will achieve an 88% NO_x emission reduction from process heaters and generate an estimated 96.56 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specifications for stationary reciprocating IC engines in §117.206(c)(9) are: 0.17 g NO_x/hp-hr for gas-fired rich-burn engines; 0.50 g NO_x/hp-hr for gas-fired lean-burn engines; 5.83 g NO_x/hp-hr for existing dual-fuel, stationary reciprocating IC engines; and 0.50 g NO_x/hp-hr for dual-fuel, stationary reciprocating IC engines initially placed into service after December 31, 2000. These emission specifications will achieve an 88% NO_x emission reduction and generate an estimated 75.63 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specifications for stationary gas turbines in §117.206(c)(10) and duct burners used in turbine exhaust ducts in §117.206(c)(11) of 0.015 lb NO_x per MMBtu heat input (or 0.15 lb NO_x per MMBtu heat input for existing stationary gas turbines rated at less than 1.0 MW) will achieve a 91% NO_x emission reduction in conjunction with the emission specification of 0.015 lb NO_x per MMBtu heat input for stationary gas turbines in §117.106(c)(3) and generate an estimated total of 140.92 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification for pulping liquor recovery furnaces in §117.206(c)(12) of 0.050 lb NO_x per MMBtu heat input (or alternatively, 1.08 lb NO_x per air-dried ton of pulp (ADTP)) will achieve a 64% NO_x emission reduction and generate an estimated 1.09 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specifications for kilns in §117.206(c)(13) of 0.66 lb NO_x per ton of calcium oxide (CaO) for lime kilns and 0.76 lb NO_x per ton of product for lightweight aggregate kilns will achieve a 39% NO_x emission reduction from the kiln category and generate an estimated 0.30 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specifications for heat treating furnaces and reheat furnaces in §117.206(c)(14) of 0.087 lb NO_x per MMBtu heat input for heat treating furnaces and 0.062 lb NO_x per MMBtu heat input for reheat furnaces will achieve a 35% NO_x emission reduction from the steel furnace category and generate an estimated 0.39 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification for magnesium chloride fluidized bed dryers in §117.206(c)(15) of a 90% reduction from the emission factor used to calculate the June - August 1997 daily NO_x emissions will achieve a 41% NO_x emission reduction from the dryer category and generate an estimated 0.95 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification for incinerators (including enclosed control devices that combust or oxidize gases or vapors) in §117.206(c)(16) of an 80% reduction from the emission factor used to calculate the June - August 1997 daily NO_x emissions; or alternatively, 0.030 lb NO_x per MMBtu heat input, will achieve a 54% NO_x emission reduction and generate an estimated 3.22 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

A new §117.206(c)(17) provides low annual capacity factor units with an alternative to the emission specifications in §117.206(c)(1) - (16). The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units 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.

The NO_x emission limit averaging times for BPA and DFW in the renumbered §117.206(d)(1) are consistent with the averaging times for NO_x RACT compliance in §117.205(b)(7). Units with NO_x emission monitors are capable of tracking emissions over time, and are allowed to demonstrate compliance on a 30-day average in BPA and DFW under this subsection. The amendments to §117.206 also revise §117.206(d)(1)(A) by changing references from "continuous emission monitors" to "continuous emissions monitoring system" and from "predictive emission monitors" to "predictive

emissions monitoring system" for consistency with the definitions of these terms in §117.10(9) and (36), respectively. For HGA, a new §117.206(d)(2) specifies that the averaging time for the ESADs shall be as specified in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, except that EGFs shall also comply with the daily and 30-day system cap emission limitations of §117.210, concerning System Cap.

The emission limits of the renumbered §117.206(e) address pollutants which may increase as an incidental result of compliance with the NO_x limits. The CO limit is consistent with the existing CO limit of §117.205(f) for RACT because nothing in these rules necessitates changing the existing limit. In rulemaking adopted on April 19, 2000, the commission intended to change the proposed ammonia limit of five ppm to ten ppm in the renumbered §117.205(e)(2) but inadvertently did not change the rule language. (See the May 5, 2000 issue of the *Texas Register* (25 TexReg 4146).) The amendment to the renumbered §117.206(e)(2) makes this correction. The ammonia limit of ten ppm is lower than the existing limit of §117.205(g) and 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 NESCAUM. It is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The commission is not including these related pollutant limits in the attainment demonstration SIP, in order to simplify the approval process for alternative emission specification under §107.221. This step will eliminate the need for case-specific SIP revisions to complete the approval of an alternate CO or ammonia limit.

The amendments to §117.106(d) also clarify the adopted rule language by changing "utility boiler" to "unit." This change will not impact any additional units in BPA and DFW because §117.106(a) and (b) only apply to utility boilers. The adopted rule language of §117.206(e) changed "boiler or process heater" to "unit." This change will not impact any additional units in BPA because §117.206(a) only applies to boilers and process heaters in BPA. In DFW, §117.206(b) likewise already applies to boilers and process heaters, and therefore this change will not impact any boilers or process heaters in DFW. Although §117.206(b) also applies to gas-fired and gas/liquid-fired lean-burn stationary reciprocating IC engines in DFW, none of the three engines in DFW which are subject to §117.206(b) would have to comply with the ammonia limit because they can meet the emission limits using low emission combustion (LEC) modifications rather than post-combustion controls.

Regarding the CO limits, the amendments to §117.206(e) specifically exclude stationary IC engines in BPA and DFW because these engines are already subject to a CO limit in §117.205(e) and §117.206(b)(2), respectively. The amendments to §117.206(e)(1) specify a CO limit for IC engines in HGA that is consistent with these existing CO standards. In addition, the amendments to §117.206(e) specifically exclude BIF units and incinerators in HGA which are already subject to CO limits in other rules (for example, 40 CFR 266.102(e)(2)(ii)(A) and 40 CFR 266.104(b)). Finally, the amendments exclude boilers and process heaters operating in "hot-standby" mode and lightweight aggregate kilns from correcting CO to 3.0% O_2, dry basis, because these units typically will operate with high excess O_2 which will drive the CO level, when corrected to 3.0% O_2, to a high level.

With the exception of the availability of alternative CO and ammonia limits through §117.221, the amendments to the renumbered §117.206(f) specify that an owner or operator in HGA may not use the alternative plant-wide emission specifications in §117.207, the alternative case-specific specifications of §117.221, the source cap in §117.223, or the trading option in §117.570, except that EGFs shall also comply with the daily and 30-day system cap emission limitations of §117.210 of this title. This is necessary to ensure that any trading that occurs is done under the Chapter 101 mass emissions cap and trade program being adopted concurrently in this issue of the *Texas Register*. The owners and operators of the equipment addressed by these Chapter 117 amendments will be required to use the compliance flexibility provided by the new Chapter 101 mass emissions cap and trade program, which will allow compliance to be established through the use of surplus reductions created from other sources.

In addition, the amendments to §117.206 revise the renumbered §117.206(g) to make the exemptions of §117.206(g)(1) and (2) unavailable in HGA for consistency with the applicability of §117.206(c). The amendments to the renumbered §117.206(g)(1) also change the order of "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the title of this division.

Finally, the amendments to §117.206 add a new subsection (h) which prohibits the owner or operator of units which utilize liquid or gaseous streams containing chemical-bound nitrogen as a source of fuel or combustion air from circumventing the emission reduction requirements by directing these streams to flares or other units which are not subject to an ESAD in §117.206(c), unless the unit which receives the chemical-bound nitrogen stream is opted into the Chapter 101 mass emissions cap and trade program, and NO_x emissions from this opt-in unit are determined using a CEMS or PEMS which meets

the requirements of §117.213(e) or (f) or through stack testing which meets the requirements of §117.211(e), concerning Initial Demonstration of Compliance.

The amendments to §117.207, concerning Alternative Plant-wide Emission Specifications, update cross-references to renumbered rules. The amendments to §117.207 also revise §117.207(b)(1) by changing references from "continuous emission monitors" to "continuous emissions monitoring system" and from "predictive emission monitors" to "predictive emissions monitoring system" for consistency with the definitions of these terms in §117.10(9) and (36), respectively.

In addition, the amendments to §117.207(f) change references to §117.206(e), which should have been §117.206(f), to §117.206(g) to account for the subsection renumbering in §117.206. The amendments to §117.207 also revise references in §117.207(f)(1) from "gas turbines" and "engines" to "stationary gas turbines" and "stationary internal combustion engines" for consistency with the definition of these terms in §117.10(41) and (42), respectively.

Finally, the amendments to §117.207(f)(4) delete the superfluous term "steam generator" since a steam generator is simply a boiler and is already addressed by this term in the Chapter 117 rules, and revise a reference from "United States Environmental Protection Agency" to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions.

The amendments to §117.208, concerning Operating Requirements, correct the format of references to §§117.205 - 117.207 and 117.223 for consistency with *Texas Register* formatting requirements, revise a

reference in §117.208(d)(4) from "gas turbines" to "stationary gas turbines" for consistency with the definition of this term in §117.10(41), and revise §117.208(d) to exclude sources subject to §117.206(c).

The new §117.210 establishes a system cap for units which generate electricity, but which will be subject to §117.206 rather than §117.106. The new §117.210, would create a flexible method of complying with the NO_x emission specifications in §117.206 for units which meet the definition of EGF. The system cap requirements in §117.210 exclude cogeneration units whose electric output entirely serves one or several dedicated industrial customers, except when the industrial customers are not operating. These sources are base load sources 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, these sources are more similar to electric generating units located at an industrial site which do not generate electricity for compensation. Because these industrial electric generators do not provide electricity for peaking, they were never included in the system cap for the reasons described in the previous paragraph.

The new §117.210 is patterned on the existing source cap compliance option in §117.108 for electric utilities. The system cap sets limits on total pounds of NO_x allowed to be emitted by EGFs which will not be subject to §117.106. A cap has the advantage over rate-based standards of allowing the source owner to control the activity levels of the regulated equipment as a means of compliance. This means that a company's compliance measures may include installing less extensive emission controls on a piece of equipment and choosing to operate it less, or upgrading its efficiency to require less fuel firing.

The amendments to §117.211 revise §117.211(e)(5) by revising a reference from "United States Environmental Protection Agency" to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions.

The amendments to §117.213, concerning Continuous Demonstration of Compliance, add a new §117.213(a)(1)(B) which specifies the totalizing fuel flow meter requirements for units at major NO_x sources in HGA which are subject to §117.206. With the exception of wood-fired boilers and pulping liquor recovery furnaces for which fuel flow monitoring is impractical, all units which are listed in §117.201 will be subject to the totalizing fuel flow meter requirements because knowledge of the fuel usage is critical in determining the emission allocations for the new Chapter 101 mass emissions cap and trade program. The existing §117.213(a)(1)(A) - (D) is being renumbered as §117.213(a)(1)(A)(i) - (iv) to accommodate the new §117.213(a)(1)(B).

The amendments to §117.213 also revise the renumbered §117.213(a)(1)(A)(ii) (currently §117.213(a)(1)(B)) to reflect the renumbering of §117.203(6) and (8) as §117.203(a)(6) and (8) and the addition of the new §117.205(h)(9) - (10), and revise §117.213(b)(2)(A) and §117.213(c)(2)(A) to reflect the addition of the new §117.205(h)(8) - (10). The existing requirement in §117.213(b) for O_2 monitors on certain boilers and process heaters will continue to apply to these sources in HGA after the emission specifications of §117.206(c) supersede those of §117.205.

In addition, the amendments to §117.213 also add new §117.213(c)(1)(G) - (I) to specify that the requirement to install a CEMS or PEMS NO_x monitor applies to the following units in HGA: lime

kilns, lightweight aggregate kilns, and units with a rated heat input greater than or equal to 100 MMBtu/hr which are subject to §117.206(c). The existing requirement in §117.213(c) for NO_x monitors on certain boilers, process heaters, stationary gas turbines, and units which use a chemical reagent for reduction of NO_x will continue to apply to these sources in HGA after the emission specifications of §117.206(c) supersede those of §117.205. Similarly, the existing requirement in §117.213(d) - (f) for CO monitoring, CEMS, and PEMS will continue to apply to these sources in HGA after the emission specifications of §117.206(c) supersede those of §117.205.

The amendments to §117.213 also revise §117.213(c)(1)(F) and (2)(A), and (k) (being renumbered as §117.213(k)(1)) to specify that these rules only apply to units in BPA or DFW, or to units in HGA which are subject to the NO_x RACT emission specifications of §117.205. A new §117.213(k)(2) specifies that for units in HGA which are subject to the ESADs of §117.206(c), the methods required in §117.213 and §117.214 shall be used in conjunction with the requirements of Chapter 101, Subchapter H, Division 3 to determine compliance. The new §117.213(k)(2) further specifies that for enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission specifications.

In addition, the amendments to §117.213 revise §117.213(g) by dividing it into two paragraphs, one for engines not using NO_x CEMS or PEMS, and one for engines using NO_x CEMS or PEMS. A new subparagraph (1)(C) specifies that gas-fired emergency generators are not required to conduct periodic testing under the renumbered §117.213(g)(1)(B).

The amendments to §117.213 also revise a reference in §117.213(h) from "gas turbines" to "stationary gas turbines" for consistency with the definition of this term in §117.10(41), and revise §117.213(i) to reflect the renumbering of §117.203(6)(B) as §117.203(a)(6)(B).

Finally, the amendments to the catchlines in §117.213(l) and (m) clarify that these subsections apply to the NO_x RACT emission specifications of §117.205.

The new §117.214 applies to units in HGA which are subject to the ESADs of §117.206(c) and specifies monitoring and testing requirements. The new §117.214(a) requires monitoring for NO_x, CO, and fuel flow as specified in §117.213(a) and (c) - (f). The new §117.214(b)(1) requires testing of each unit which is subject to the emission specifications of §117.106(c). The testing requirements are consistent with the testing previously required of these units for NO_x RACT under §117.211. A new §117.214(b)(2) adds a quarterly engine testing requirement, based upon the existing §117.208(d)(7). Because quarterly emission testing for engines that run no more than ten hours per month could result in these engines operating when they otherwise would be idle, thereby increasing emissions, the commission has included language which states that 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.

Regarding emission allowances for the new Chapter 101 mass emissions cap and trade program, §117.214(c) specifies that the NO_x testing and monitoring data specified in §117.214(a) and (b),

together with the level of activity, as defined in §101.350, are used to establish the emission factor for the mass emissions cap and trade program. For units without CEMS or PEMS, retesting is required after any modifications which could increase the NO_x emission rate, but is optional after any modifications which could decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), FGR, and fuel-lean and conventional (fuel-rich) reburn. The NO_x emission rate determined by the retesting establishes a new emission factor which must be used instead of the previously determined emission factor for the new Chapter 101 mass emissions cap and trade program.

The amendments to §117.216, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, revise §117.216(a)(1) to reference the system cap of 117.210 and the Chapter 101 mass emissions cap and trade program being adopted concurrently in this issue of the *Texas Register*. This revision is necessary because the owners and operators of the equipment addressed by these Chapter 117 revisions will be required to use the compliance flexibility provided by the new Chapter 101 mass emissions cap and trade program, which will allow compliance to be established through the use of surplus reductions created from other sources.

The amendments to §117.219, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.219(a) by correcting the reference to §101.11 to reflect the recent title change of this section from “Exemptions from Rules and Regulations” to “Demonstrations.” (See the July 14, 2000 issue of the *Texas Register* (25 TexReg 6727)).

The amendments to §117.219 also replace the term “performance evaluation” with “relative accuracy test audit” in §117.219(b)(2) to more accurately describe the CEMS or PEMS performance evaluation; and replace the term “executive director” with “appropriate regional office” in §117.219(c) to more precisely specify where at the agency the test results are to be sent.

The amendments to §117.219 reduce the semiannual report requirements of §117.219(d) for sources in the HGA mass emissions cap and trade program that are not subject to (or no longer subject to) §117.205 to a monitoring system report.

In addition, the amendments to §117.219 revise references in §117.219(d)(1)(A) and the renumbered §117.219(f)(4) from "gas turbine" to "stationary gas turbine" for consistency with the definition of this term in §117.10(41).

The amendments to §117.219 also revise a reference in the renumbered §117.219(f)(3) from "internal combustion engine" to "stationary internal combustion engine" for consistency with the definition of this term in §117.10(42), and revise a reference in the renumbered §117.219(f)(4) from "gas turbine" to "stationary gas turbine" for consistency with the definition of this term in §117.10(41).

In addition, the amendments to §117.219(f) renumber paragraphs (1) - (8) as (2) - (9) to accommodate the new §117.219(f)(1), and add a new §117.219(f)(1) in order to specify that records of annual fuel usage shall be kept for each unit subject to the totalizing fuel flow meter requirements of §117.213(a). The amendments to the renumbered §117.219(f)(2) add a new subparagraph (C) for units subject to the

mass emissions cap and trade program since compliance with the ESADs in HGA will be on an annual basis. However, EGFs subject to the system cap of §117.210 additionally will be required to keep daily records under §117.219(f)(2)(B). Finally, the amendments to the renumbered §117.219(f)(3)(A)(i) correct a typographical error in a reference to §117.208(d)(7).

The amendments to §117.221, concerning Alternative Case Specific Specifications, revise §117.221(a) to reflect the renumbering of §117.206(d) as §117.206(e), and revise a reference in §117.211(b) from "United States Environmental Protection Agency" to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions. The amendments to §117.221(a) also add a reference to §117.206(e).

The new requirements of §117.471, concerning Applicability; §117.473, concerning Exemptions; §117.475, concerning Emission Specifications; §117.478, concerning Operating Requirements; and §117.479, concerning Monitoring, Recordkeeping, and Reporting Requirements, apply to stationary reciprocating IC engines, boilers, and process heaters located in HGA at stationary sources of NO_x which are not major sources of NO_x. Therefore, a new Division 2, concerning Boilers, Process Heaters, and Stationary Engines at Minor Sources, is being added to Subchapter D, concerning Small Combustion Sources.

The adopted emission specifications are essential components of and consistent with the HGA Attainment Demonstration SIP, adopted concurrently by the commission. The emission specifications and ozone attainment demonstration SIP are required by 42 USC, §7410 and §7511a, which require

states to submit SIPs to the EPA which contain enforceable measures to achieve the NAAQS. The process by which the emission specifications were developed is described in the BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES section of this preamble.

The new §117.471 specifies that the new Division 2, concerning Boilers, Process Heaters, and Stationary Engines at Minor Sources, which is being added to Subchapter D, concerning Small Combustion Sources, applies to stationary reciprocating IC engines, boilers, and process heaters located in HGA at a stationary source of NO_x which is not a major source of NO_x.

The new §117.473 exempts boilers and process heaters with a maximum rated capacity of 2.0 MMBtu/hr or less. This exemption is included because units with a maximum rated capacity of 2.0 MMBtu/hr or less are already regulated under Subchapter D, Division 1, concerning Water Heaters, Small Boilers, and Process Heaters.

In addition, the following engines are exempt in the new §117.473: engines used in research and testing; engines used for purposes of performance verification and testing; engines used solely to power other engines or gas turbines during start-ups; engines operated exclusively for firefighting and/or flood control; engines used in response to and during the existence of any officially declared disaster or state of emergency; and 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. This exemption is consistent with the exemption in the renumbered §117.203(3) which is available for stationary sources of NO_x which are major sources of NO_x. The new §117.473 also exempts stationary reciprocating IC

engines with a hp rating of 50 hp or less and emergency generators that do not operate more than 100 hours per year.

In addition, the new §117.473 establishes an exemption for certain boilers and process heaters located at any stationary source of NO_x which is not subject to Chapter 101, Subchapter H, Division 3. The boilers and process heaters qualify for this exemption if the maximum rated capacity is greater than 2.0 MMBtu/hr and less than 5.0 MMBtu/hr and the annual heat input is less than or equal to 1.8 (10^9) Btu per calendar year; or if the maximum rated capacity is equal to or greater than 5.0 MMBtu/hr and the annual heat input is less than or equal to 9.0 (10^9) Btu per calendar year. However, the totalizing fuel flow requirements of §117.479(a), (d), and (g)(1) will apply to these exempted units in order to document that the annual heat input conditions of the exemption are met.

The new §117.473(c) exempts from the requirements of Chapter 117 all combustion units which would meet the requirements of a standard permit currently being developed for electricity-generating combustion units rated at no more than ten MW in capacity and which emit no more than 0.015 lb NO_x/MMBtu heat input. The commission is adding this exemption to facilitate the installation of small (ten MW or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid. This exemption is intended to provide an incentive for installation and use of new clean energy-producing technology. The emission limit of the proposed standard permit is consistent with the adopted ESAD of 0.015 lb NO_x/MMBtu heat input.

The new §117.475 establishes an emission specification of 0.036 lb NO_x per MMBtu heat input (or alternatively, 30 ppmv NO_x, at 3.0% O_2, dry basis) for boilers and process heaters in HGA at non-major stationary sources of NO_x. The new §117.475 also establishes an emission specification of 0.50 g NO_x/hp-hr for gas-fired stationary reciprocating IC engines in HGA at non-major stationary sources of NO_x. A new §117.475(c)(3) provides low annual capacity factor units with an alternative emission specification. The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units 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.

The new §117.478 specifies techniques to be used to minimize NO_x emissions. Section 117.478(b)(1) requires boilers to be operated with O_2, CO, or fuel trim. Such systems can pay for themselves with fuel savings while reducing NO_x due to low excess air operation and reduced firing. Fuel trim has been demonstrated as an effective control technique for natural gas fired boilers operating with FGR to achieve compliance with a 30 ppmv NO_x limit.

The new §117.478(b)(2) requires operation of boilers and process heaters equipped with forced FGR such that the proportional design rate of FGR is maintained over the operating range.

The new §117.478(b)(3) requires operation of any post combustion controls such that the injection rate of the reducing agent (i.e., ammonia or urea) is maintained to limit NO_x concentrations to no more than the NO_x concentrations achieved at maximum rated capacity.

The new §117.478(b)(4) requires engines controlled with nonselective catalytic reduction (NSCR) to be operated with an air-fuel ratio (AFR) controller which operates on exhaust O_2 or CO.

The new §117.478(b)(5) is based upon the existing §117.208(d)(7) and requires engines to be checked for proper operation measuring and recording 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, or catalyst cleaning or catalyst replacement. The new §117.478(b)(5) allows the use of stain tube indicators specifically designed to measure NO_x concentrations, 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. The new §117.478(b)(5) also allows the use of portable NO_x analyzers. Because quarterly emission testing for engines that run no more than ten hours per month could result in these engines operating when they otherwise would be idle, thereby increasing emissions, the commission has included language which states that 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.

The new §117.479 specifies the monitoring, recordkeeping, and reporting requirements for boilers, process heaters, and engines which are subject to the emission specifications of §117.475.

The new §117.479(a) requires installation of totalizing fuel flow meters because knowledge of the fuel usage is critical in determining the NO_x emission rate as well as the emission allocations for the new Chapter 101 mass emissions cap and trade program.

The new §117.479(b) does not require O_2 monitors, but instead specifies that if an owner or operator installs an O_2 monitor, then the criteria in §117.213(e) is the appropriate guidance for the location and calibration of the monitor.

The new §117.479(c) does not require NO_x monitors, but instead specifies that if an owner or operator installs a NO_x monitor, then it must meet the CEMS or PEMS requirements of §117.213(e) or (f).

The new §117.479(d) specifies that monitors must be installed on the schedule specified in §117.534.

The new §117.479(e) specifies the testing requirements for boilers, process heaters, and engines which are subject to the emission specifications of §117.475. These requirements are based upon the existing requirements of §117.211. Section 117.479 also specifies that for units without CEMS or PEMS, retesting is required after any modifications which could increase the NO_x emission rate, but is optional after any modifications which could decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), FGR, and fuel-lean and conventional (fuel-rich) reburn. The NO_x emission rate determined by the retesting establishes a new emission factor which must be used instead of the previously determined emission factor for the new Chapter 101 mass emissions cap and trade program.

The new §117.479(f) specifies that the NO_x testing and monitoring data specified in §117.479(a) - (e), together with the level of activity, as defined in §101.350, are used to establish the emission factor for the new Chapter 101 mass emissions cap and trade program.

The new §117.479(g) specifies the records to be used to demonstrate compliance with the emission specifications of §117.475.

The new §117.479(h) specifies the recordkeeping requirements for engines which are necessary to document exemption status.

The amendments to §117.510, concerning Compliance Schedule for Utility Electric Generation, revise §117.510(c) to create separate paragraphs in this subsection addressing compliance schedules for the NO_x RACT rules and the emission specifications for attainment demonstrations. For investor-owned electric utilities, the commission is adopting a staged six-year implementation schedule for compliance with the new HGA emission specifications. First, 46% of the total reductions required to comply with the emission specifications are required by March 31, 2003. The next 46% of the reductions are required by March 31, 2004. The final reductions are required by March 31, 2007. The commission believes that this compliance schedule is appropriate for investor-owned electric utilities since emission reduction projects are already underway to implement the majority of the emission reductions necessary to meet the ESADs for investor-owned electric utilities. A combination of combustion controls and flue gas cleanup controls will be necessary on many units.

The amendments to §117.510(b)(2) modify the compliance schedule for utility boilers in DFW by allowing exclusion of boilers which are to be retired and decommissioned before May 1, 2005 from the calculation of the emission reductions to be made by May 1, 2003. This two-year compliance schedule extension will avoid the costs associated with installation of controls which would be used for a relatively short period of time, yet still achieve the necessary emission reductions from the soon-to-be-retired utility boilers before the critical 2005 ozone season, thereby contributing to DFW's attainment of the ozone NAAQS. To qualify for this compliance date extension, a boiler must be designated by the PUCT to be necessary to operate for reliability of the electric system, and the owner must provide the executive director an enforceable written commitment by May 1, 2003 to retire and permanently decommission the boiler by May 1, 2005.

In addition, the amendments to §117.510 add the missing word "in" to §117.510(a)(2)(E)(iii) and (F) and the renumbered §117.510(b)(2)(A)(v)(III) and (vi). The amendments to §117.510 also make a variety of minor punctuation corrections throughout the section. Finally, the amendments to §117.510 revise §117.510(a)(2)(A)(i) and the renumbered §117.510(b)(2)(A)(i)(I) by replacing a reference to the effective date of these rules with the actual effective date, May 11, 2000.

The amendments to §117.520, concerning Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas, revise §117.520(c) to create separate paragraphs in this subsection addressing compliance schedules for the NO_x RACT rules and the emission specifications for attainment demonstrations. The commission is adopting a staged six-year implementation schedule for compliance with the new HGA emission specifications. First, 44% of the

total reductions required to comply with the emission specifications are required by March 31, 2004, 2003. The next 45% of the reductions are required by March 31, 2005. The final reductions are required by March 31, 2007. A combination of combustion controls and flue gas cleanup controls will be necessary on many units.

In addition, the amendments to §117.520 add the missing word "in" to §117.520(a)(3)(B)(v) and (E)(iii) and the renumbered §117.510(b)(2)(A)(v)(III) and (vi). The amendments to §117.520 also revise §117.520(a), (b), and (c) by changing the order of "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the title of this division. Finally, the amendments to §117.520 revise §117.520(a)(3)(A)(i) by replacing a reference to the effective date of this rule with the actual effective date, May 11, 2000.

The new §117.534 specifies the compliance schedule for boilers, process heaters, and stationary engines at minor sources in HGA. For sources subject to the new Chapter 101 mass emissions cap and trade program, the commission is adopting a staged six-year implementation schedule for compliance with the new HGA emission specifications. First, 44% of the total reductions required to comply with the emission specifications are required by March 31, 2004. The next 45% of the reductions are required by March 31, 2005. The final reductions are required by March 31, 2007. For sources not subject to the new Chapter 101 mass emissions cap and trade program, the emission reductions are required by March 31, 2005.

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 §39.263(c)(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

Since Chapter 117 is an applicable requirement under 30 TAC Chapter 122, 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 has reviewed the rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and has determined that the rulemaking meets the definition of a "major environmental rule" as defined in that statute. "Major environmental rule" means a rule the specific intent of which is to protect the environment or reduce risks to human health from

environmental exposure and that may adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

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

The amendments to Chapter 117 will require emission reductions from electric utility boilers and stationary gas turbines; ICI boilers and stationary gas turbines; duct burners used in turbine exhaust ducts; process heaters and furnaces; stationary IC engines; FCCUs (including catalyst regenerators and CO boilers and furnaces); pulping liquor recovery furnaces; lime kilns; lightweight aggregate kilns; heat treating furnaces; reheat furnaces; magnesium chloride fluidized bed dryers; incinerators (including enclosed control devices that combust or oxidize gases or vapors); and BIF units in the HGA ozone nonattainment area. 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 sources in the HGA ozone nonattainment area with a potential to emit NO_x in amounts greater than or equal to ten tons per year (tpy), as well as boilers, heaters, and stationary engines at sources with a potential to emit NO_x in amounts less than ten tpy. These sources comprise sectors of the economy (including petroleum refineries, petrochemical plants, and electric generating plants) in a sector of the state. This is based on the analysis provided in the rule proposal preamble which was published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275), including the discussion in the Public Benefit and Costs section.

The amendments implement requirements of the FCAA. 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 42 USC, §7410, does not require specific programs, methods, or reductions in order to meet the standard, state SIPs must include "enforceable emission limitations and other control measures, means or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance as may be necessary or appropriate to meet the applicable requirements of this chapter," (meaning Chapter 85, Air Pollution Prevention and Control). It is true that the FCAA 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 the FCAA. The provisions of the FCAA recognize that states are in the best position to determine what programs and controls are necessary or appropriate in order to meet the NAAQS. This flexibility allows states, affected industry, and the public, to collaborate on the best methods for attaining the NAAQS for the specific regions in

the state. Even though the FCAA allows states to develop their own programs, this flexibility does not relieve a state from developing a program that meets the requirements of 42 USC, §7410. Thus, while specific measures are not generally required, the emission reductions are required. States are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule.

The requirement to provide a fiscal analysis of proposed regulations in the Texas Government Code was amended by Senate Bill (SB) 633 during the 75th Legislative Session. 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, the FCAA 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. Since the legislature is presumed to understand the fiscal impacts of the bills it passes, and that presumption is based on information provided by state agencies and the LBB, the commission believes that the intent of SB 633 was only to require the full RIA for rules that are extraordinary in nature. While the SIP rules will have a broad impact, that impact is no greater than is necessary or appropriate to meet the requirements of the FCAA. For these reasons, rules adopted for inclusion in the SIP fall under the exception in Texas Government Code, §2001.0225(a), because they are required by federal law.

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 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. These rules will also satisfy requirements for implementation of NO_x RACT at major sources in HGA which are not subject to the previous NO_x RACT rules. The FCAA, 42 USC, §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 42 USC, §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 42 USC, §7511a(f), exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under 42 USC, §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 TNRCC has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App.–Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App.–Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the

number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

As discussed earlier in this preamble, this rulemaking implements requirements of the FCAA. There is no contract or delegation agreement that covers the topic that is the subject of this rulemaking. In addition, the rulemaking complies with the requirements of 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. Comments received during the comment period regarding the draft RIA are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

TAKINGS IMPACT ASSESSMENT (TIA)

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 and to implement NO_x RACT required by 42 USC, §7511a(f) for certain source categories. Texas Government Code, §2007.003(b)(4), provides that Chapter 2007

does not apply to these adopted rules since 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 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 NOx 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. Another purpose is to satisfy the NO_x RACT requirements at major sources in HGA which are not subject to the previous NO_x RACT rules. The FCAA, 42 USC, §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.

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 federal ambient air quality standard 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 has included elsewhere in this preamble its reasoned justification for adopting this strategy and has 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 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. Comments received during the comment period regarding the TIA are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

COASTAL MANAGEMENT PROGRAM CONSISTENCY REVIEW

The commission has 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 has reviewed this rulemaking action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and has 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 Part 50, National Primary and Secondary Ambient Air Quality Standards, and 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal Of Implementation Plans. 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 comment period regarding the CMP consistency review.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000.

Two hundred fifty-one commenters submitted testimony on the proposal. Pasadena Paper Company LP, Pasadena Pulp Company LP, and Donohue Industries Incorporated submitted joint comments and will be referred to as Pasadena/Donohue. The League of Women Voters of Texas (LWV-TX); Manufacturers of Emission Controls Association (MECA); Public Citizen; Sustainable Economic and Environmental Development (SEED); and 19 individuals supported the proposed revisions, while Hispanic Community of Texas Citizens for a Sound Economy (TCSE-HC); JB Services; RMT, Inc. on behalf of Montgomery County (Montgomery Co.); Safety-Kleen (Deer Park), Incorporated (Safety-Kleen); and four individuals opposed the proposed revisions. Baker Botts L.L.P. (Baker Botts); BASF Corporation (BASF); Baytown Chamber of Commerce (Baytown COC); BP; Business Coalition for Clean Air (BCCA); Calpine Central, L.P. (Calpine); Chevron Phillips Chemical Company LP (Chevron); City of Baytown (Baytown); City of Houston Department of Health and Human Services (HDHHS); City of Missouri City (Missouri City); City of Spring Valley (Spring Valley); Clean Air Partnership (CAP); Clear Lake Area Chamber of Commerce (Clear Lake COC); Corpus Christi Air Quality Committee; Corpus Christi City Council Member Arnold Gonzales; Crown Central Petroleum Corporation (Crown); Diamond-Koch; Dow Chemical Company (Dow); DuPont; Dynegy, Incorporated (Dynegy); East Harris County Manufacturers Association (EHCMA); Engine Manufacturers Association (EMA); Enron; Entergy Services, Incorporated (Entergy); Enterprise Products Operating L.P. (Enterprise); EPA; Equistar Chemicals LP (Equistar); ExxonMobil Corporation (ExxonMobil); Fuel Tech, Incorporated (Fuel Tech); Galveston County Judge Jim Yarbrough; Galveston-Houston Association for Smog Prevention (GHASP); Gas Processors Association (GPA); Goodyear Rubber and Tire Company (Goodyear); Grandparents of East Harris County (GEHC); Harris County Judge Robert Eckels; Houston Metropolitan Planning Organization's Transportation Policy Council (Houston MPO);

Kaneka Texas Corporation (KTC); Kinder Morgan, Incorporated (Kinder Morgan); Lyondell Chemical Company (Lyondell); Lyondell-Citgo Refining LP (Lyondell-Citgo); Mothers for Clean Air; National Aeronautics and Space Administration (NASA); Pasadena/Donohue; Pavilion Technologies, Incorporated (Pavilion); PECO Energy Company (PECO); Phillips 66 Company (Phillips 66); Regional Air Quality Consensus Group (RAQCG); Reliant Energy, Incorporated (REI); Rhodia, Incorporated (Rhodia); RMT, Incorporated (RMT); Sierra Club - Galveston Regional Group (Sierra-Galveston); Sierra Club - Houston Regional Group (Sierra-Houston); Solar Turbines Incorporated (Solar Turbines); Solutia; State Representative Jaime Capelo; State Senator Carlos Truan; Tennessee Gas Pipeline Company (TGP); Texas Association of Business and Chambers of Commerce (TABCC); Texas Chemical Council (TCC); Texas City Mayor Carlos Garza; Texas Eastern Transmission Corporation (Texas Eastern); Texas Gulf Coast Asthma Coalition (TGCAC); Texas Industry Project (TIP); Texas Medical Center Central Heating and Cooling Services Cooperative Association (TECO); Texas Oil and Gas Association (TxOGA); Texas Pulp and Paper Industry Environmental Council (TPIEC); Trunkline Gas Company (TGC); TXI Operations, L.P. (TXI); TXU Business Services (TXU); Union Carbide Corporation (Union Carbide); Valero Refining Company-Texas (Valero); Wyman-Gordon Forgings (Wyman-Gordon); and 148 individuals supported the proposed revisions but suggested changes or clarifications.

BP supported the comments submitted by TIP and TCC, except as noted in the ANALYSIS OF TESTIMONY section. Chevron supported the comments submitted by BCCA and TCC. Corpus Christi Air Quality Committee, Corpus Christi City Council Member Arnold Gonzales, State Representative Jaime Capelo, and two individuals supported the comments submitted by State Senator

Carlos Truan. Crown supported the comments submitted by TxOGA. Dow and Lyondell supported the comments submitted by BCCA, TCC, and TIP. DuPont supported the comments submitted by TCC. Dynegy and Enron supported the comments submitted by BCCA. Entergy and TPIEC supported the comments submitted by TIP. Equistar supported the comments submitted by BCCA, EHCMA, TCC, and TIP. ExxonMobil supported the comments submitted by BCCA, EHCMA, TCC, TIP, and TxOGA. Goodyear and REI supported the comments submitted by BCCA and TIP. Harris County Judge Robert Eckels supported the comments submitted by CAP, Houston MPO, and RAQCG. Lyondell-Citgo supported the comments submitted by BCCA and TxOGA. Pasadena/Donohue supported the comments submitted by TPIEC. Phillips 66 supported the comments submitted by BCCA, TCC, TIP, and TxOGA. Valero supported the comments submitted by BCCA, TIP, and TxOGA.

ANALYSIS OF TESTIMONY

GENERAL COMMENTS

LWV-TX; MECA; Public Citizen; SEED; TGCAC; and 19 individuals supported the proposed revisions to Chapter 117.

The commission appreciates the support.

TCSE-HC; JB Services; Safety-Kleen; and four individuals opposed the proposed revisions to Chapter 117. Montgomery Co. and one individual opposed implementation of the proposed Chapter 117

revisions in Montgomery County, four individuals opposed implementation of the proposed Chapter 117 revisions in Chambers County, and six individuals opposed implementation of the proposed Chapter 117 revisions in Liberty County.

As noted earlier in this preamble, the amendments are necessary to implement requirements of the FCAA. 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. 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 rules, which reduce ambient NO_x and ozone in HGA, will be submitted after adoption to the EPA as one of several measures of the required new attainment demonstrations. These rules will also satisfy the NO_x RACT requirements at major sources in HGA which are not subject to the previous NO_x RACT rules. The FCAA, 42 USC, §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. Further, the adopted rules are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. The adopted rules satisfy these federal requirements and are necessary to ensure that the current SIP revision in support of the HGA ozone attainment demonstration will be federally approvable.

Furthermore, the FCAA Amendments of 1990 provided new requirements for areas that had not attained the NAAQS for ozone, carbon monoxide, particulate matter, sulfur dioxide, nitrogen dioxide, and lead, and new requirements for SIPs in general. The EPA was authorized to designate areas failing to meet the NAAQS for ozone as nonattainment and to classify them according to severity. FCAA, §107(d)(4)(A)(iv) mandated that areas designated as serious, severe, or extreme for ozone that were within a metropolitan statistical area (MSA) or CMSA must have boundaries that include the entire MSA or CMSA. This requirement is supported by the legislative history for the FCAA Amendments in Senate Report No. 101-228, page 3399, which states that "Because ozone is not a local phenomenon but is formed and transported over hundreds of miles and several days, localized control strategies will not be effective in reducing ozone levels. The bill, thus, expands the size of areas that are defined as ozone nonattainment areas to assure that controls are implemented in an area wide enough to address the problem." The FCAA Amendments did provide the ability to exclude portions of the entire MSA or CMSA prior to designation, if the state conducted a study that the EPA agreed proved that the geographic portion did not contribute significantly to violation of the NAAQS.

Redesignation has not occurred for any portion of the HGA nonattainment area, and is not currently being considered. For existing areas currently included within a nonattainment area, the specific area must be redesignated as attainment to be removed from a nonattainment area. FCAA, §107(d)(3) provides that the EPA may not redesignate a nonattainment area, or a portion thereof, to attainment unless several criteria are met, which include: a determination that the area has attained the NAAQS; there is a fully approved SIP for the area; there is a determination

that the improvement in air quality is due to permanent and enforceable reductions in emissions; there is an approved maintenance plan for the area; and the state has met all requirements for the area under FCAA, §110 and Part D.

However, even if a specific area within the HGA nonattainment area was redesignated by the EPA as attainment for ozone, reductions associated from all adopted ozone control strategies would still be necessary because of the requirements of FCAA, §107(d)(3) and §175A, which require maintenance plans for all redesignated areas. The maintenance plan must include the measures specified in §107(d)(3) and any additional measures that are necessary to ensure that the area continues to be in attainment with the NAAQS for ten years after the redesignation. Eight years after the redesignation, the state is required to submit an additional revision to the SIP for maintaining the NAAQS for ten years after the end of the first ten-year period.

Additionally, reductions associated with the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies.

At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever increasing number of air quality professionals have concluded that ozone is a regional problem requiring regional strategies in addition to local control programs. As nonattainment areas across the United States prepared

attainment demonstration SIPs in response to the 1990 FCAA Amendments, several areas found that modeling attainment was made much more difficult, if not impossible, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The commission has conducted air quality modeling and upper air monitoring that found regional air pollution should be considered when studying air quality in Texas' ozone nonattainment areas. This work is supported by research conducted by OTAG, the most comprehensive attempt ever undertaken to understand and quantify the transport of ozone. Both the commission and the OTAG study point to the need to take a regional approach to controlling air pollutants. In fact, the transport of ozone-forming chemicals has been conclusively demonstrated both in modeling and ambient air analyses over distances far greater than that from southern counties in the HGA nonattainment area to downtown Houston.

One individual commented that the rules go beyond anything necessary to protect the environment, the basis and analysis in the rules is flawed, and the rules are being set up to embarrass Texas and the Governor, and the individual hopes that state legislators and Congress would investigate these plans. The individual also commented that the TNRCC and the EPA should be downsized because less government is better than more government.

The commission does not agree that the rules are too broad or that the basis or analysis of the rules is flawed. As noted earlier in this preamble, the amendments are necessary to implement requirements of the FCAA. 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. 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 rules, which reduce ambient NO_x and ozone in HGA, will be submitted after adoption to the EPA as one of several measures of the required new attainment demonstrations. These rules will also satisfy the NO_x RACT requirements at major sources in HGA which are not subject to the previous NO_x RACT rules. The FCAA, 42 USC, §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. The adopted rules satisfy these federal requirements and are necessary to ensure that the current SIP revision in support of the HGA ozone attainment demonstration will be federally approvable. Further, the adopted rules are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. The commission's intent is not to embarrass Texas and the Governor but instead to comply with the timelines provided in 1990 FCAA amendments and subsequent EPA guidance for submitting rules to demonstrate ozone attainment in HGA. Accordingly, Texas has committed to adopting the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000.

GEHC and fifty-one individuals commented that more should be done to reduce emissions from NO_x point sources, particularly EGFs, refineries, chemical plants, and sources along the ship channel.

It is true that emissions from refineries or other significant point sources like those along the ship channel or Texas City may account for an important part of HGA emissions. It is also true that all parts of HGA make significant contributions to air pollution and that reductions from major point sources alone will not be enough to meet federal air quality standards. To meet the federal ozone standard, it will be necessary for additional sources of pollution to be reduced. The commission believes that the adopted rules include an appropriate level of control for NO_x point sources, taking into consideration the technical feasibility described later in this preamble.

An individual commented that Houston does not have the geographic restrictions that Los Angeles has (i.e., mountain ranges preventing pollution from being blown away), that Houston still has the worst pollution in the United States, and that stricter point source rules are needed.

The commission agrees with the commenter that Houston and Los Angeles have different geographical features that may either contribute to ozone formation or inhibit ozone formation and dispersion. For example, while HGA may not have nearby mountains that impede air flow, it does have a common summer weather pattern peculiar to this part of the Gulf Coast. The same air moves in from the Gulf during the day and out to the Gulf during the night, without really going anywhere (analogous to a bathtub sloshing effect). The geography of the Gulf Coast contributes to this weather pattern and makes it more difficult to attain the ozone standard. The

commission continues to study the unique geographic and meteorologic features of HGA to determine their role in ozone formation and dispersion. Additionally, the adopted rules for HGA include an overall 85% NO_x reduction from point sources, as well as reductions in on-road mobile sources, non-road mobiles sources, and area sources. It should be noted that the adopted stringent controls on NO_x point sources, plus the other control measures (including gap measures), are necessary for the commission's modeling to show modeled attainment in HGA. Therefore, controls on all segments of the inventory are needed.

Five individuals suggested tax incentives for installation of pollution control equipment.

Such tax incentives are already available. In 1993, Texas voters approved the Proposition 2 constitutional amendment, which provides property tax exemptions on property used for pollution control purposes. The intent of this amendment is to ensure capital investments undertaken to comply with environmental mandates do not result in an increase in property taxes. The rules governing this property were adopted under 30 TAC Chapter 17, and under these rules, the TNRCC is responsible for determining whether property is used for pollution control purposes, and whether a facility may apply for a property tax exemption to its local appraisal district.

Sierra-Galveston, GEHC, GHASP, and thirty-five individuals expressed concern about enforcement of the proposed rules. Seventeen of these individuals recommended high penalties for noncompliance. One individual commented that the enforcement of the rules in Liberty County would be difficult

because they would be hard pressed to justify allocating resources and manpower to enforce these types of rules when there are more serious problems in that area.

The commission agrees that adequate enforcement is critical to the success of the program. As with all of its rules, the commission will enforce the requirements after the compliance date and take appropriate action for noncompliance situations. The commission will work with local officials to ensure enforcement of the SIP and SIP rules. The commission has existing relationships with pollution control authorities in the City of Houston, Harris County, and Galveston County for enforcement of other commission rules. The commission will continue enforcement relationships with these entities and develop relationships with other local officials as needed to create effective enforcement mechanisms for the SIP and SIP rules.

Missouri City questioned whether it would be required to enforce the proposed Chapter 117 revisions.

The rules are enforced by staff in the TNRCC's regional offices, as well as local air pollution control programs. Local governments have the same power and are subject to the same restrictions as the commission under TCAA, §382.015, Power to Enter Property, to inspect the air and to enter public or private property in its territorial jurisdiction to determine if the level of air contaminants in an area in its territorial jurisdiction meet levels set by the commission. Local governments are not required to enforce commission rules but may sign cooperative agreements with the commission to enforce the rules under TCAA, §382.115, Cooperative Agreements. Local programs can also enforce commission rules without signing a cooperative agreement. The

authority of local governments to enforce air pollution requirements is specified in detail in TCAA, §§382.111 - 382.115, and local governments can institute civil actions in the same manner as the commission pursuant to Texas Water Code, §7.351.

An individual suggested that the commission provide technical experts to industry in order to assist industry in implementing projects to meet the proposed emission specifications. The individual also suggested that the public be informed about these projects.

The TNRCC's technical experts in the Air Permits Division are available to assist in answering questions concerning the permitting of such projects. Staff in the TNRCC's Pollution Prevention and Industry Assistance Section are also available to provide suggestions for reducing pollution. Ultimately, however, the regulated community is responsible for implementation of its own projects. Regarding the commenter's suggestion that the public be informed about projects to meet the emission specifications, the commission notes that the list of the pending permit projects is available on the commission's website at: http://www.tnrcc.state.tx.us/updated/air/nsr/nsrmap.shtml. In addition, the new source review (NSR) permitting program is subject to the public notice requirements found in 30 TAC Chapter 39.

Two individuals stated that all requirements should apply statewide, while GHASP stated that all requirements should apply in east Texas.

The commission appreciates the commenters' support for state-wide applicability of the adopted rules. The commission notes, however, that it is not obligated to adopt all rules statewide in order to satisfy its commitments under the SIP, nor is the commission required to do so under the FCAA. Three of the adopted measures contain emission reduction strategies that have been adopted with state-wide applicability: California large-spark ignition engines; emissions banking and trading program (that portion of the adopted rules which relates to the trading of emission reduction credits and discrete emission reduction credits); and cleaner diesel fuel (that portion of the adopted rules which relates to on-highway fuel).

In evaluating whether to implement all of the rules statewide, the commission took into account many concerns, including the need for the marketplace to be able to respond to regulation, the possible impacts on transport and distribution systems, the possibility of increased costs and financial burdens on regulated entities, and regional needs and issues associated with state-wide mandates. The commission analyzed where emission reduction measures are most needed and where emission reduction measures will be most effective in order to demonstrate attainment.

An individual suggested that all emission reductions should be completely voluntary.

The EPA provides for the inclusion of voluntary programs or measures as part of the attainment demonstration, but limits the amount of emission reduction credit that may be claimed from such measures, due to the fact that the programs are not enforceable mechanisms. In accordance with EPA policy, the commission has included some voluntary programs as part of the HGA SIP. The

Houston Galveston Area Council (HGAC) is the entity responsible for the development and implementation of these programs, which are detailed in the HGA SIP as the Voluntary Mobile Source Emissions Reduction Program (VMEP). If these rules became voluntary, they could not be counted as an enforceable measure obtaining emission reductions for the demonstration of attainment. As stated elsewhere in this preamble, the emission reductions associated with these rules are necessary for the attainment of the NAAQS in the HGA area.

Four individuals stated that Ellis County cement kilns should meet the same standards as EGFs in DFW.

No changes were proposed to the Chapter 117 NO_x emission specifications for cement kilns. Therefore, the commission cannot revise the Chapter 117 cement kiln rules in this rulemaking because the newly affected parties in Ellis County would not have had adequate notice and opportunity to comment. However, there have been recent developments regarding post-combustion controls on cement kilns in Europe and Asia. Because these developments indicate that post-combustion controls are technically feasible on dry-process cement kilns, the commission may revisit the Chapter 117 NO_x emission specifications for cement kilns if additional emission reductions are determined to be necessary to reach attainment with the ozone NAAQS in the future. The commission has made no change in response to the comment.

Two individuals stated that the commission should lobby to exempt Texas EGFs from the requirements of the National Fuel Use Act of 1978, which mandated a move toward the use of coal rather than

natural gas. GHASP and an individual stated that the commission should require conversion of coal-fired EGFs to natural gas.

The provision of the Fuel Use Act that prohibited the use of natural gas was repealed in 1985. A diversity of fuel sources is in the interest of the consumer to limit the effect of price increases. There is also a substantial investment in the coal infrastructure, and consumer prices would be affected by the suggested conversion of coal-fired EGFs to natural gas. Also, insufficient natural gas reserves exist in this country to make a major shift away from coal as a baseload utility fuel. According to the PUCT, coal supplies more than 50% of the utility generation on a national basis. It would be unrealistic to assume that coal-fired EGFs could shut down or convert all coal-firing to natural gas.

GHASP stated that air pollution control technology should be required on all coal-fired EGFs. An individual stated that best available control technology (BACT) should be required on all coal-fired EGFs in HGA and all of east Texas.

The adopted Chapter 117 rules include emission specifications for coal-fired EGFs based on REI's design specifications. The operation of these units in HGA will set a new standard as BACT for coal upon successful in-use demonstration and will result in an estimated 92% reduction in NO_x emissions from the 1997 emissions inventory. In addition, the commission adopted emission specifications on April 19, 2000 for coal-fired EGFs in east and central Texas which will result in a 50% reduction in NO_x emissions. (See the May 5, 2000 issue of the *Texas Register* (25 TexReg

4101).) The commission may pursue additional emission reductions from EGFs in east and central Texas if those reductions are determined to be necessary to reach attainment with the ozone NAAQS in the future. The commission has made no change in response to the comment.

Galveston County Judge Jim Yarbrough, Harris County Judge Robert Eckels, Houston MPO, RAQCG, Texas City Mayor Carlos Garza, and an individual stated that the Chapter 117 requirements should provide for maximum flexibility, consistent with current and emerging technologies and retrofit feasibility and necessary NO_x emission reductions.

The commission has included flexibility to the extent possible while still achieving the emission reduction goals. Specifically, 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 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 rule proposal preamble, 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 ESADs.

An individual stated that the Chapter 117 requirements should only apply to industries within 27 miles of the central city on days when emissions are excessive (greater than 150 parts per billion) for more than two consecutive hours over two consecutive days.

The commission disagrees with the comment because such a proposal would not reduce emissions until an exceedance of the ozone standard had already occurred. As noted earlier in this preamble, reductions are required in the entire HGA ozone nonattainment area. Further, FCAA, §123, prohibits control techniques which are conditional upon atmospheric conditions.

TXU noted that the rule proposal preamble requested comments on allowing trading between different electric power generating companies in the DFW area to increase flexibility. TXU strongly supported development of such a rule and stated that the rule should allow simple trading between electric utilities with a program similar to the SB 7 trading provisions. TXU urged the commission to begin development of such a rule. TXU stated that the commission should also simultaneously develop a trading rule for inter-utility trading in the East Texas attainment area. TXU stated that such trading programs are essential in achieving the PUCT's objectives of minimizing cost and promoting potential competition for the cost-effective generation of electricity.

In response to the comments, the commission initiated rulemaking which would establish trading rules for DFW and east and central Texas. Specifically, the proposed new §117.109, System Cap Flexibility, §117.110, Change of Ownership - System Cap, and §117.139, System Cap Flexibility, would add flexibility to the trading of NO_x emissions in DFW and in east and central Texas by allowing the exceedance of a system emissions cap, provided emission reductions are obtained from another participant in a system cap to offset the exceedance. On November 15, 2000, the commission approved the proposed rules for publication in the *Texas Register*. (See the December 1, 2000 issue of the *Texas Register* (25 TexReg 11878).) Final action will be taken on this rule proposal by May 31, 2001.

TXI commented that its lightweight aggregate kilns are "an extremely small contributor to the total point source NO_x emissions in the HGA," and asserted that it is "widely known that the ozone problem in nonattainment areas are largely the result of mobile source emissions."

Even though lightweight aggregate kiln emissions form a relatively small fraction of the total emissions in HGA, the same can be said of most categories of emission sources. The commenter's logic of exempting all source sectors because each individually contributes only marginally to the area's ozone problem would cumulatively result in an inadequate plan for the area's attainment of the ozone standard due to no emissions reductions whatsoever. While mobile sources contribute a significant share of the ozone-forming pollutants in HGA, modeling analyses show that reducing mobile source emissions alone will not be sufficient to bring the area into attainment. In many cities with ozone problems, such as DFW and Atlanta, it is true that mobile source emissions are primarily responsible for ozone production, but even in those areas point sources make significant contributions. In the HGA emissions inventory projected to 2007, point sources contribute about 60% of the anthropogenic emissions of NO_x, which means that paradigms which apply to mobile source-dominated areas are not applicable in HGA.

The 2007 future emissions inventory was developed which included all applicable adopted state and federal controls. A number of sensitivity model runs were made with this inventory. These sensitivity analyses indicated that no one control measure would provide significant change in ozone concentrations. However, the modeling shows that when an ensemble of a number of controls were applied together, these will provide for significant reductions in ozone concentrations. The SIP outlines a number of controls that when applied together will provide for significant reductions in ozone.

TXI commented that its lightweight aggregate kilns in Clodine could not affect HGA generally and that all exceedances are to the east of the kilns.

Because significant contributions to air pollution occur throughout the HGA area, reductions from sources within Houston alone will not be enough to meet federal air quality standards. It is not surprising that exceedances in HGA have been documented only to the east of TXI's kilns since there are no air quality monitors to the west of Clodine.

TGP commented that many point sources operate only during fall and winter months and do not contribute significantly to ozone.

Ozone exceedances in HGA occur most frequently from early April to late October. In 2000, the first exceedance occurred on April 14, and the latest exceedance occurred on October 20. October and April comprise two of the months cited by the commenters as unnecessary for regulation. The commission's rules are written to prevent an ozone exceedance at any time of the ozone season.

Sierra-Houston commented that the commission did not conduct a model run with the specific Chapter 117 rules proposed, instead modeling an across-the-board 90% NO_x reduction, and that the commission has no SIP that the public can review and comment upon with accurate modeling.

Since the SIP revision was proposed, the commission has revised its modeling of point source emissions. Specific emission rates were modeled for all major EGFs in the area. Other point sources (with the exception of some minor NO_x sources such as flares) are now assumed to be reduced by 85% overall. It is reasonable to assume an across-the-board reduction for the non-EGFs, since in concurrent rulemaking published elsewhere in this issue of the *Texas Register* the commission adopted a mass emissions cap and trade program for HGA. Thus, modeling explicit reductions for all sources would be of limited benefit, since many sources will doubtless trade emissions allowances among themselves.

CAP commented that the commission should affirmatively demonstrate through photochemical modeling that whatever mix of control strategies is finally selected will be sufficient to achieve attainment by 2007.

The commission has used the best information available along with state-of-the-science modeling to develop a plan that is expected to bring the area into attainment by 2007. As new information and better science become available over the next several years, the commission will continue to evaluate plans for the area, and, if necessary, refine the plans to reflect the most current information.

Sierra-Houston resubmitted comment letters dated August 2, 1999, January 31, 2000, and February 24, 2000 concerning already-completed rulemakings and SIP revisions which Sierra-Houston had initially submitted during the comment period for these previous rulemakings and SIP revisions.

These comments were 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*.

Sierra-Houston commented on the NO_x emission reduction tables published in the August 25, 2000, issue of the *Texas Register* (25 TexReg 8479 - 8482). Sierra-Houston stated that the estimated reductions in the Tier I column plus the estimated reductions in the Tier II column do not add up to the estimated reductions in the Tier III column.

The Tier I column represents the estimated reductions resulting from combustion modifications, while the Tier II column represents the estimated reductions resulting from post-combustion controls. These columns list the estimated emission reductions if only these controls were applied. The Tier III column lists the estimated emission reductions if combustion modifications and post-combustion controls were applied. It is smaller than the sum of the Tier I and Tier II columns to avoid double-counting the emission reductions that would occur from the application of either Tier I or Tier II controls alone. In certain categories, such as process heaters, the Tier I reduction reflects maximal measures and the Tier III reduction is less than the maximal Tier I plus Tier II reduction, to reflect the mix of feasible reductions. The maximal levels in each Tier are not feasible on every unit.

Baker Botts commented that it generally supports the ongoing efforts by the commission to develop a SIP that is technologically achievable, economically reasonable, and legally approvable. Baker Botts,

BCCA, Dynegy, Equistar, ExxonMobil, Goodyear, Harris County Judge Robert Eckels, Phillips 66, Spring Valley, TCC, TPIEC, TxOGA, Valero, and an individual commented that the commission should incorporate into the SIP a greater level of reductions from federally preempted sources and stated that EPA-regulated sources account for about 40% of the NO_x emissions in the HGA. The commenters stated that the EPA issued a number of regulations for some federally preempted sources, such as land-based spark engines, marine, recreational and land-based diesel engines, aircraft and locomotive engines, well after the FCAA deadlines, and that the EPA recently strengthened rules for on-road and non-road vehicles and fuels, such as low sulfur gas and diesel, Tier II motor vehicles, heavy-duty highway vehicle standards, and non-road Tier II/Tier III heavy-duty engine standards. The commenters stated that delays in implementing these rules have prompted the commission to propose technically and economically infeasible emission reductions from sources in HGA that the state has authority to regulate to make up for the missing federal reductions. The commenters stated that these delays have forced the commission to propose expensive regional fuels and significant use restriction regulations. The commenters stated that the commission and the EPA can ensure an equitable distribution of the compliance burdens necessary to meet mandated air quality improvement in HGA only by allowing the SIP to capture anticipated emission reductions from federally preempted sources. Baker Botts noted that the EPA demonstrated a willingness to assume responsibility for a portion of emission reductions created by a process in Los Angeles called a “public consultative process,” that would resolve issues related to emissions from national and international sources, and that the EPA has also provided flexibility in obtaining offsets by allowing states to provide offsets to refiners based on emission reductions that the EPA projected would result from mobile sources using Tier II gasoline. Baker Botts suggested that this same sort of prospective crediting should be used to develop a more

rational HGA SIP, and that the EPA should allow the commission to credit in the SIP the prospective emission reductions that will result from implementation of the Tier II gasoline rule and from other federally preempted sources. Finally, Baker Botts cited two cases wherein the District of Columbia Circuit has approved the EPA's flexibility with respect to statutory deadlines under the FCAA when the EPA has failed to meets its own deadlines, and this failure was deemed to upset the balanced federal/state responsibilities under the FCAA. ExxonMobil commented that it supports the commission and the EPA crediting the HGA SIP with an additional 60 tpd of federally preempted emission reductions that will occur over the next ten years. Harris County Judge Robert Eckels commented that the commission should work with the EPA to accelerate the implementation schedule for federally preempted emissions so that at least one-half of the related emission reductions are achieved by 2007, and that as a part of this process, the commission should delineate federal assignments detailing the engine standards and emission reductions necessary to achieve real and sustainable pollution reductions.

The commission agrees with the commenters that emission reductions from federally preempted sources would provide benefits for the HGA SIP demonstration, and the inability of the commission to regulate certain source categories has necessitated the use of other ozone control strategies. However, the commission understands that the EPA SIP approval process does not provide a mechanism for credit for emission reductions that occur after the attainment date. The commission understands that the EPA is not currently considering accelerating implementation schedules for existing federal rules. The commission is working with the EPA to determine the availability of SIP credit for many non-traditional control strategy mechanisms, like economic incentive programs and flexibility for preempted source categories. Additionally, the commission

is working with the EPA to determine an appropriate federal contribution credit available for the HGA SIP.

RIA COMMENTS

BCCA, Entergy, ExxonMobil, Goodyear, GPA, Kinder Morgan, Lyondell, PECO, Phillips 66, REI, TPIEC, TXI, and TxOGA commented on the draft RIA and stated that the proposed rules were not evaluated in accordance with the analysis requirements for a major environmental rule. The commenters stated that Texas Government Code, §2001.0225, requires an RIA for certain major environmental rules. The commenters stated that the commission must consider the benefits and costs of the proposed rule in relationship to state agencies, local governments, the public, the regulated community, and the environment. The commenters stated further that the commission must also incorporate aspects of this analysis into the fiscal note in the proposed rules (e.g., identify the costs and the benefits; describe reasonable alternative methods for achieving the purpose of the rule considered by the agency; provide the reasons for rejecting those alternatives; and identify the data and methodology used in performing the analysis). The commenters stated that under §2001.0225(d) the commission must also find that "compared to the alternative proposals considered and rejected, the rule will result in the best combination of effectiveness in obtaining the desired results and of economic costs not materially greater than the costs of any alternative regulatory method considered."

The commenters stated that the rule proposal preamble's statement that the rules are exempt from the RIA requirement because federal law mandates the rules is a legally flawed effort to avoid an RIA and may render the rules invalid. The commenters stated that federal law does not mandate the control

requirements, emission rates, and use restrictions contained in the proposal and asserted that many of the proposed rules exceed specific federal rules and standards applicable to the same sources. The commenters stated that examples of departures from the federal framework include the following: boiler, turbine, and other fired equipment emission limits set well below federal new source performance standards (NSPS), RACT, BACT, or lowest achievable emission rate (LAER) limits for the same sources; and compressor engine emission limits set at unprecedented low levels specifically designed to be unachievable and prevent the further use of the affected engines.

TXI stated that the NAAQS do not provide in and of themselves any standards applicable to the regulated community, and that a state with an approved SIP has broad flexibility on how to meet the NAAQS. TXI stated that the commission failed to cite "an 'express requirement of state law' that justifies the promulgation of the proposed rule without complying with the mandates of §2001.0225." TXI stated that none of the state laws cited in the rule proposal preamble (TCAA, §§382.011, 382.012, and 382.017) is “an ‘express requirements of state law’ to adopt these NO_x emission rules.”

TXI commented that *The Senate Natural Resources Committee, Interim Report to the 75th Legislature, Use of Cost Benefit Analysis in Environmental Regulation* (September 1996) regarding Texas Government Code, §2001.0225, states on page 8 that "(t)he heightened scrutiny approach would be applied only to the environmental regulations that are *not specifically required* by federal law, a federally-delegated program agreement or an express requirement of state law. Obviously, if the agency has *no discretion about whether to adopt regulations*, it should not be required to prepare a heightened scrutiny document." (TXI's emphasis supplied).

TXI stated that the commission must quantify the costs associated with the proposal either for the purpose of determining the reasonableness of the proposed NO_x controls for achieving the commission's desired result or for complying with the specified requirements of Texas Government Code,§2001.0225. TXI asserted that the commission did not perform a study of the costs associated with the proposed rule for lightweight aggregate kilns. TXI also asserted that the commission did not perform a quantitative analysis of the estimated cost to the Texas lightweight aggregate industry and that without such an analysis, the commission cannot determine the reasonableness of the proposed rule from an economic perspective.

The commenters stated that the rule proposal preamble acknowledges that the rule proposal's components are "major environmental rules," but that the commission asserted that an RIA is "seldom" required and is only required for "extraordinary" rules. The commenters stated that these criteria appear nowhere in the RIA requirements. The commenters stated that the rule proposal preamble states that "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." The commenters stated that this "no greater than is necessary or appropriate" determination is the conclusion that an RIA is designed to evaluate and to offer for public review and comment. The commenters stated that the rule proposal is well beyond any federal mandates for the covered sources and are "extraordinary." The commenters stated that under Texas Government Code, §2001.0225, an RIA must be performed and offered for public comment before the proposal can be adopted.

The commission agrees with the commenters that the rules meet the definition of a major

environmental rule; however, the commission disagrees that its interpretation of the exemption for federally mandated standards is legally flawed. While the rules may require significant capital investments by owners or operators of the types of units affected by these rules, that alone is not enough to trigger the RIA requirements. The Texas Government Code, §2001.0225, only applies to a major environmental rule adopted by a state agency, 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.

This rulemaking action does not meet any of these four applicability requirements, and is adopted in substantial compliance with the RIA requirements. Texas Government Code, §2001.035. These rules do not exceed an express standard set by federal law because the emission specifications are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. Title 42 USC, §7410, requires states 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 42 USC, §7410, does not specifically prescribe programs, methods, or reductions to meet the federal standard, state SIPs must include "enforceable emission limitations and other control measures, means or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance as may be necessary or appropriate to meet the applicable requirements of this chapter" (meaning

FCAA, Chapter 85, Air Pollution Prevention and Control). The FCAA does require some specific measures for SIP purposes, such as an inspection and maintenance program, but those programs are the exception, not the rule, in the federal SIP structure. The provisions of the FCAA recognize that states are in the best position to determine what programs and controls are necessary or appropriate in order to meet the NAAQS. This flexibility allows states, affected industry, and the public, to collaborate on the best methods for attaining the NAAQS for the specific regions in the state. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Failure to develop control strategies to demonstrate attainment can result in federal sanctions. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commissions photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended, in part, to achieve reductions in ozone emissions in the HGA nonattainment areas. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA. Further, these rules will also satisfy the NO_x RACT requirements at

major sources in HGA which are not subject to the previous NO_x RACT rules. The FCAA, 42 USC, §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. The adopted rules satisfy these federal requirements and are necessary to ensure that the current SIP revision in support of the HGA ozone attainment demonstration will be federally approvable.

This conclusion is supported by the legislative history for Texas Government Code, §2001.0225. During the 75th Legislative Session, SB 633 amended the Texas Government Code to require agencies to perform an RIA of certain rules. The intent of SB 633 was to require agencies to conduct an RIA of 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. 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. Because of the ongoing need to address nonattainment demonstrations required by federal law, the commission routinely proposes and adopts SIP rules. If each rule proposed for inclusion in the SIP was incorrectly considered as exceeding federal law, every SIP rule would require the full RIA contemplated by SB 633. This result would be inconsistent with the cost estimates and fiscal notes prepared by the commission and by the LBB. Since the legislature is presumed to understand the fiscal impacts of the bills it

passes, and that presumption is based on information provided by state agencies and the LBB, the commission believes that the intent of SB 633 was only to require the full RIA for rules that meet the requirements under §2001.0225(a). 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. In other words, the adopted rules are intended to meet federal and state law, and does not go above and beyond what is required to meet federal or state statutes.

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. Texas Government Code, Chapter 2001, presumes that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." ***Central Power & Light Co. v. Sharp*****, 919 S.W.2d 485, 489 (Tex. App.–Austin 1995),** ***writ denied with per curiam opinion respecting another issue*****, 960 S.W.2d 617 (Tex. 1997);** ***Bullock v. Marathon Oil Co.*****, 798 S.W.2d 353, 357 (Tex. App.–Austin 1990, no writ).** ***Cf. Humble Oil & Refining Co. v. Calvert*****, 414 S.W.2d 172 (Tex. 1967);** ***Sharp v. House of Lloyd*****, Inc., 815 S.W.2d 245 (Tex. 1991);** ***Southwestern Life Ins. Co. v. Montemayor*****, 24 S.W.3d 581 (Tex. App.--Austin 2000,** ***pet. denied*****); and** ***Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*****, 563 S.W.2d 916 (Tex. 1978).**

The commission's interpretation of the RIA requirements is also supported by a change made to the APA by the legislature in 1999. In an attempt to limit the number of rule challenges based

upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225, as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore, in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, 382.016, 382.017, and 382.051(d), authorize the commission to implement a plan for the control of the state's air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

REASONED JUSTIFICATION COMMENTS

Entergy, Enterprise, Equistar, Goodyear, Lyondell, PECO, Phillips 66, TPIEC, and TxOGA stated that the commission has not provided a reasoned justification for the proposal. The commenters asserted that a rule that would impose an air emission abatement requirement that is not demonstrated to be practical and economically feasible is directly contrary to the TCAA, §382.011(b), and therefore is inconsistent with the Texas Government Code, §2001.033(a)(1)(B) and §2001.035(c).

The commission has provided a "reasoned justification" for the rules in this adoption package as required by Texas Government Code, §2001.033. The requirement for a reasoned justification applies to the agency order finally adopting a rule. The standard for compliance with the reasoned justification requirement is substantial compliance, as determined by the Legislature, which amended the reasoned justification requirement in 1999. The commission has provided the factual, policy and legal bases for the rule, as required. Texas Government Code, §2001.024, requires only "a brief explanation" of the rules upon proposal in addition to other elements such as the fiscal note and public benefit evaluations. Both the rule proposal and adoption meet all of the requirements of the APA.

NOTICE COMMENTS

Entergy, ExxonMobil, Equistar, Lyondell, PECO, Phillips 66, REI, TPIEC, and TxOGA stated that the proposed rules did not include adequate notice as required under Texas Government Code, §2002.024. The commenters stated that Texas Government Code, §2001.024, requires adequate notice of a proposed rule, including information about its public benefits and costs. The commenters stated that adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule, and that courts have considered notice "adequate" only if: interested persons can confront the agency's factual suppositions and policy preconceptions; and the agency provides interested parties the opportunity to challenge the underlying factual data relied upon by the agency. The commenters asserted that in proposing the rules, the commission failed to provide interested parties with sufficient information to constitute adequate notice.

The commenters stated that the rule proposal preamble appears short of adequate notice because the cost estimates were “dramatically underestimated.” The commenters stated that actual point source capital costs that would result from the rule proposal were in some instances ten to fifteen times the capital costs used in calculating the dollar-per-ton estimates in the preamble. The commenters stated that presenting a single average cost-per-ton figure for each point source category, instead of a range, masked the extremely high costs faced by some source categories. The commenters stated that the commission published insufficient information and analysis regarding costs and impacts.

The commenters noted further that the rule proposal preamble states that the cost estimates for controlling many point sources were "derived" from certain cost models and questioned how the costs were derived. The commenters also noted that the rule proposal preamble stated that "there may be individual sources for which the equipment actual control costs are higher than the ones identified in this cost note," and asserted that through this statement the commission “acknowledged that its estimates may have been low.” The commenters stated that the commission published insufficient information and analysis regarding costs and impacts. The commenters stated that the commission “has not been completely responsive to stakeholder requests for information necessary to comment effectively” and “dramatically underestimated" the costs of the proposed control strategies, and that as a result, the notice of the proposal is inadequate.

The commenters stated that it has identified a number of critical gaps in the underlying factual data, methodology, and analysis in support of the proposed rules. The commenters asserted that the proposal included insufficient information and analysis regarding costs and impacts. The commenters asserted

that the commission has not adequately responded to requests for additional information from stakeholders. The commenters stated that the following requests for information were outstanding: information regarding the modeling of emissions; information regarding the corrected emissions inventory database; and information supporting the estimated costs of control. The commenters stated that this information is necessary in order to comment effectively on the proposed rules and that data gaps in the proposal hindered effective comment. Solutia expressed similar concerns regarding the cost estimates.

The commission disagrees with the commenters and has made no change in response to these comments. Texas Government Code, §2001.024 requires that the notice of a proposed rule include certain information. Subsection (a)(5) requires that the notice state the public benefits expected as a result of the adoption of the proposed rule and the probable economic cost to persons required to comply with the rule. Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn*, 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of the proposed rules. The preamble for the proposed rules contained a discussion of the FCAA requirements concerning the affected NO_x point sources, a detailed section by section discussion of the proposed changes, a fiscal note, including the cost to state and local governments, the public

benefit and the estimated costs for the affected sources, a small and micro-business analysis, a draft RIA, a TIA, and a CMP consistency determination. The commission received intelligent comments which were substantial both in number and in scope, regarding the costs as well as the benefits. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the notice must include the cost of a typical and reasonable method of compliance. The commenters' statements that the costs were "dramatically underestimated" did not state how that conclusion was reached. Mere disagreement with cost estimates does not render notice inadequate.

The proposed rules met the requirement to include sufficient information in explaining the requirements for NO_x point sources, the compliance schedule, the anticipated cost of compliance, and the anticipated reduction in emissions. To simply state that the proposal failed to provide sufficient information does not provide the commission with sufficient information to propose changes or alternative strategies. The commenters did not say how the notice is insufficient, but merely claimed that it is insufficient. Nevertheless, the commission has reviewed the notice and has determined it is adequate. The commission's responses to comments regarding costs associated with compliance with the rules are found later in this preamble. The commission is

unaware of any requests for additional information to which it was not completely responsive.

LOCAL EMPLOYMENT IMPACT STATEMENT COMMENTS

Entergy, ExxonMobil, Equistar, Goodyear, Lyondell, Phillips 66, REI, TPIEC, and TxOGA stated that the proposed rules did not include the local employment impact statement required under Texas Government Code, §2001.022. The commenters stated that Texas Government Code, 2001.022, requires the commission to determine whether the rule proposal has the potential to affect a local economy before proposing the rule for adoption. The commenters stated that if answered affirmatively, the commission must request that the Texas Employment Commission to prepare a local employment impact statement describing in detail the probable effect of the rule on employment in each geographic area affected by the rule for each year of the first five years that the rule will be in effect. The commenters further asserted that the commission failed to make the required initial determination and ignored the potential for the proposal to adversely affect the local economy. The commenters stated that a local employment impact statement should have been requested and prepared in advance of the proposal.

The commission agrees with the commenters that the adopted rules may affect a local economy; however, it does not agree that it is the responsibility of the commission to provide the local employment impact analysis. The APA requires state agencies to determine whether a rule may affect a local economy before proposing a rule for adoption. If the agency determines that a proposed rule may affect a local economy, the agency must send a copy of the proposed rule and other information to the Texas Workforce Commission (Workforce Commission) before the

agency files notice of the proposed rule with the secretary of state. The APA requires the Workforce Commission to prepare a local employment impact statement for proposed rules, if a state agency requests the statement. The commission determined that the proposed rules might affect a local economy, and sent the proposed rules and other requested information to the Workforce Commission. The commission received a letter from the Workforce Commission, indicating that the Workforce Commission did not have the ability to determine the potential local employment impacts from the proposed rules.

TIA COMMENTS

Entergy, ExxonMobil, Equistar, Goodyear, Lyondell, Phillips 66, REI, TPIEC, and TxOGA stated that the proposed rules did not include an adequate TIA as required under Texas Government Code, §2007, with Goodyear stating that the proposal amounts to a taking of its engines (including a recently retrofitted engine) "not supported by adequate scientific support, public participation, or legal process." The commenters stated that the TIA provision mandates that covered agencies "take a 'hard look' at the private real property implications of the actions they undertake…," according to the Office of the Attorney General, *Private Real Property Rights Preservation Act Guidelines*, (21 TexReg 387, January 12, 1996). The commenters stated that under §2007.043, a TIA must describe the specific purpose of the proposed action, determine whether engaging in the proposed governmental action will constitute a taking, and describe reasonable alternative actions that could accomplish the specified purpose. The commenters stated that the agency must also explain whether these alternative actions also would constitute takings.

The commenters stated that agencies must also comply with guidelines developed by the Texas Attorney General when developing the TIA and that according to these guidelines, agencies must carefully review governmental actions that have a significant impact on the owner's economic interest. The commenters stated that these guidelines include the statement: "Although a reduction in property value alone may not be a 'taking,' a severe reduction in property value often indicates a reduction or elimination of reasonably profitable uses." (21 TexReg 392, January 12, 1996). The commenters stated that examples of aspects of the rule proposal that could significantly impact private real property in a manner that constitutes a taking include gas-fired compressor engines and other point source NO_x controls. The commenters stated that the rule proposal preamble acknowledged that retrofitting compressor engines to the level specified in the proposal is infeasible (25 TexReg 8137 and 8291), and stated that the existing equipment, representing a significant capital improvement at a number of industrial sites, would be rendered unusable. The commenters stated that the 90% point source reduction requirement is economically and technologically infeasible for a number of existing sites, and that this requirement could cause a number of facilities to shut down their operations, dramatically impacting the value of their real property.

The commenters stated that the proposed rule preamble acknowledged that some of the rules may "burden" private real property but claimed an exemption from performing a TIA based on the assertion that the proposal does not impose a greater burden than necessary to advance a health and safety purpose and that the proposal "reasonably" fulfills a federal mandate. The commenters stated that the commission provided the public no basis to infer that a cost/benefit analysis or a reasonableness determination was, in fact, performed as necessary to support the TIA exemption claim because the

preamble contains only the bare assertions. The commenters asserted that the proposed rules will impose a greater burden than is necessary, and are not reasonably taken to fulfill a federal mandate. The commenters commented that according to the Attorney General's Guidelines, a full TIA was required to be completed with the proposal, and that failure to perform a TIA could invalidate the rules.

As stated previously in the preamble, the purpose of the adopted rules is to ensure emission reductions which 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 and to satisfy the NO_x RACT requirements at major sources in HGA which are not subject to the previous NO_x RACT rules. The acknowledgment that the rules may require a capital investment or the installation of controls, is simply that, an acknowledgment. The commission understands that the rules may have an impact on real property and in noting this, sought comments on any potential impact to ensure that the adopted rules are technically and economically feasible. The commission believes that this acknowledgment has caused the commenters to misunderstand the commission's interpretation of the requirements of Texas Government Code, Chapter 2007. The commission does not believe that the assessment required by Chapter 2007 begins with a determination of whether or not the proposed rules could result in a capital expenditure. Rather, the commission believes that before an assessment is required, the commission must determine whether Chapter 2007 applies to the government action. If the proposed action is subject to an exception to Chapter 2007, the analysis is complete. Section 2007.003(b) provides that "this chapter does not apply to the following governmental actions:…." Because the commission believes the adopted rules meet the two exceptions to Chapter 2007

discussed below, the full takings impact assessment is not required for the rules.

The commission believes the adopted rules are exempt under Texas Government Code, §2007.003(b)(4), because they are reasonably taken to fulfill an obligation mandated by federal law. While several governmental actions are subject to being reviewed under Chapter 2007, including the adoption of rules, §2007.003(b)(4) specifically excludes an action that is reasonably taken to fulfill an obligation mandated by federal law. The rules are adopted to meet the air quality standards established under federal law as NAAQS. The commission also believes that the adopted rules meet an additional exception to the requirements of Texas Government Code, Chapter 2007. 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 federal ambient air quality standard 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 HGA. Consequently, these rules meet the exemption in §2007.003(b)(13). The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has 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 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.

SMALL BUSINESS AND MICRO-BUSINESS ASSESSMENT COMMENTS

Entergy, ExxonMobil, Equistar, Goodyear, Lyondell, Phillips 66, REI, TPIEC, and TxOGA stated that the proposed rules did not include an adequate small business and micro-business assessment as required under Texas Government Code, §2006.002. The commenters stated that an analysis of the costs of compliance for small and micro-businesses must also compare the costs of compliance for these businesses with the costs for the largest businesses affected by the rule. The commenters stated that the comparison must use at least one of the following standards: cost for each employee, cost for each hour of labor, or cost for each $100 of sales. The commenters asserted that the rule proposal failed to include the mandated cost comparison standards. The commenters stated that this is the case even in those instances where the commission acknowledged a significant impact. The commenters stated that the commission either restated the costs of compliance it identified in the analysis of public benefits and costs, or concluded that it cannot determine the cost to small businesses. The commenters stated that the rule proposal preamble stated that "the estimated capital and annualized cost of installing and operating control technology used for the various types of equipment in fiscal note would appear to be a reasonable cost estimate for small and micro-businesses." (25 TexReg 8293).

The commenters asserted that the rule proposal's assessments fall short of what Texas law requires and that it is not sufficient for the agency merely to state that the costs for small and large businesses will be the same. The commenters stated that the rationale behind requiring a comparison using an established standard (e.g., cost for each employee, cost for each hour of labor, or cost for each $100 of sales) is to determine whether there is a disparate impact on small businesses. The commenters stated that according to *Unified Loans v. Pettijohn*, 955 S.W.2d at 652 (Court of Appeals - Austin, 1997), the statute's purpose is to obtain "an objective assessment of the agency's proposed action by forcing it to consider seriously. . . the effect of the rule on small businesses, including an analysis of their costs of (compliance) and a comparison of their costs with the cost of compliance for the largest businesses affected. …" The commenters stated further that the commission cannot merely conclude that the costs to small businesses "cannot be determined," and is obliged to include in the notice "some basis" for its conclusion so that interested parties can "confront that basis in a meaningful way in their comments." (*Unified Loans v. Pettijohn*, 955 S.W.2d at 653.)

The commenters stated that in the rule proposal preamble, the commission did not publish the information mandated by Texas law and that as a result, it is impossible for the public to comment on whether the agency adequately considered the effect of the rule on small businesses, thus rendering the notice of the plan inadequate. The commenters stated that Texas Government Code, §2006.002, requires the commission to provide a comparison of the proposed rule's impact on small and large businesses, using the specified standards, for public review and comment before adoption.

The commission stated in the small business and micro-business assessment in proposal preamble

that it was unable to identify any such businesses that would be affected by the proposed amendments. (See the August 25, 2000 issue of the *Texas Register* (25 TexReg 8293).) Since the commission was unable to identify any small or micro-businesses or know which facilities subject to these emission specifications are owned by small or micro-businesses, it was not possible to provide an analysis based on the number of employees, hours of labor, or amount of sales income. Nevertheless, in order to provide a basis for comments on the potential impacts for small or micro-businesses, the commission estimated, to the extent possible, the costs based on the estimated annualized cost for installing and operating control technology in dollars per ton of NO_x reduced that was used for various types of units in the fiscal note in the proposal preamble. Since the commission did not have access to the information contemplated by the statute, the use of an annualized cost was a meaningful way to provide sufficient notice of the cost to small and micro-businesses, and therefore meets the objective of Texas Government Code, Chapter 2006. Although the commission received numerous comments on the rules, none of the commenters identified themselves as small or micro-businesses.

TECHNICAL FEASIBILITY - GENERAL COMMENTS

BP stated that the emission specifications are technically feasible at its plants, except in a "very *limited* number of combustion sources." (BP's emphasis supplied). BCCA stated that the emission specifications are technically infeasible and have no proven performance experience upon which to base a reasonable and technically viable regulatory program. BCCA commented that technologies for reducing NO_x emissions are available for a wide range of processes and combustion devices, but stated that these technologies alone will not produce a 90% reduction in NO_x emissions. Crown, Harris

County Judge Robert Eckels, RAQCG, and Union Carbide questioned the technical feasibility of meeting the proposed limits. BCCA stated that three key options for NO_x control are available: application of retrofit control technology on existing equipment; replacement or consolidation of existing equipment; and shutdown of existing equipment. BCCA asserted that there is no evidence in the proposed rule that the commission weighed and analyzed the technical feasibility of the potential control options that operators will be required to use to reach NO_x reduction targets, and that the commission has assumed that retrofit control technology on existing equipment will work in all cases.

The commission agrees that 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. The commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of the adopted 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 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 later in this preamble.

Baytown, Baytown COC, BCCA, EHCMA, Entergy, Enterprise, ExxonMobil, Lyondell-Citgo, TABCC, Phillips 66, Union Carbide, Valero, and nine individuals recommended that the ESADs be revised to require approximately 75% NO_x reductions (i.e., comparable to the rules in California's

South Coast Air Quality Management District (SCAQMD)) rather than 90% as proposed. BP and GHASP supported the proposed 90% NO_x reductions.

The commission retained most components of the measures associated with the 90% point source NO_x reductions because anything less would jeopardize the approvability of the attainment plan. After estimating for emissions of new sources and making some adjustments to reflect technical feasibility issues, the overall reduction is estimated at 85%.

CAP stated that the 90% reductions appear to be greater than those required in any other nonattainment area.

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.

There are other large urban areas with a severe ozone designation and a petroleum refining presence, such as Philadelphia. Philadelphia, however, is primarily basing its current attainment

projections on reductions in regionally transported ozone. Likewise, Milwaukee and Chicago are focusing on reductions in regionally transported ozone. Some of the other severe ozone nonattainment areas have not completed development of their emission specifications for the one-hour attainment demonstrations required by the 1990 FCAA.

In addition, areas in the country other than Houston have large concentrations of refining and petrochemical plants. Most of these areas have smaller populations and less total on-road and non-road emissions, and therefore either already attain the one-hour ozone standard or are predicted to attain the standard with far more modest reductions than required in Houston. Such areas include Corpus Christi, BPA, and Lake Charles, Louisiana.

BCCA suggested that the commission consider establishing a partnership with the regulated community to develop technologically feasible standards for point source categories which have very few, if any, NO_x retrofit applications in the United States. BCCA stated that examples of these sources include ethylene plant pyrolysis furnaces, lean-burn IC engines, hydrogen generation reactor furnaces, BIF units and other incinerators, and FCCUs.

The commission appreciates BCCA's offer of cooperation. The commission has based the ESADs on its own analysis of technical feasibility, which included seeking factual input from the regulated community. The commission notes several points in response to these comments. First, the frame of reference for retrofit experience is not limited to the United States. Much experience with SCR was obtained in Japan and Germany in the 1980s before significant commercial operation of SCR

in the United States. Second, there are a large number of lean-burn IC engine retrofits in the United States as a result of the NO_x RACT requirements of the FCAA, 42 USC, §7511a(f).

BCCA, Entergy, Equistar, ExxonMobil, and Lyondell asserted that most of the emission limitations were developed with a less than complete analysis of the technical feasibility of the proposed controls.

The commission analyzed the technical feasibility of each proposed ESAD and did not propose any it believed to be technically infeasible. There are a vast number of point sources in the HGA area 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. The commission has re-examined the issues of technical feasibility in response to public comment. After considering the technical feasibility issues raised by commenters it has adjusted several standards where it believes the case has been made that the level of control is not demonstrated and may be impracticable.

BCCA and ExxonMobil stated that the commission appears to have first established an arbitrary NO_x reduction target for point sources (i.e., 90%) and, through an iterative process, back-calculated the emission limits necessary to achieve the desired target. BCCA and ExxonMobil stated that this is "an arbitrary approach to establishing air pollution standards, and circumvents the intent established in the Texas Clean Air Act to establish standard based on a technological and economical review of available

control measures."

The 90% point source emission reduction target was not developed arbitrarily. It was proposed and adopted in the May 1998 modeling SIP submitted to the EPA, as a high level estimate of technical feasibility of applying maximal point source NO_x controls. The May 1998 modeling SIP was subject to public notice and comment. The logic for the 90% NO_x reduction was based on non-arbitrary premises: first, that SCR is physically capable of achieving this kind of NO_x reduction on most exhaust streams, and second, that the technology has been applied to only a handful of units in HGA and thus is likely to be available areawide to achieve substantial reductions. The ability of combustion modifications to provide an increased share of the reductions in those cases where SCR could not provide a full 90% reduction was also considered. The 90% point source target remained as a policy goal because subsequent iterations of modeling and investigations into the feasible reductions in other categories led to the conclusion that attainment of the ozone NAAQS in HGA by 2007 would necessitate this level of point source reduction, if not more. 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. Despite the apparent logic behind the Tier III approach that even higher reductions than 90% could be achieved if Tier III were applied to approximately 1,200 small boilers, heaters, and incinerators, the commission retained the May 1998 goal of 90% reduction in the August, 2000 rule development. Proposing NO_x reductions less than 90% could have jeopardized the success of the plan. Greater than 90% NO_x reductions would have resulted in increased economic burdens

on a numerically large number of sources contributing only a small portion of total point source emissions.

In the work leading to the August, 2000 rule proposal, the commission staff evaluated the 1997 emissions inventory in detail and considered various combinations of emission specifications for various categories of equipment to achieve a 90% NO_x reduction. The result of this analysis was that a 90% NO_x reduction would require ESADs very near technically feasible Tier III limits for many categories. The design of the ESADs by category to achieve a concrete policy goal of a 90% reduction also enabled the commission to propose ESADs for a vast number of very small heaters and boilers at Tier I levels, which is key to the practicability of the adopted plan. Comparability of emission rates across equipment types was a consideration. For example, the adopted ESAD applicable to existing gas turbines rated at less than 1.0 MW is comparable to the adopted ESAD for lean-burn engines. The usage of units in these two categories are very similar. Responses to comments concerning costs are discussed in detail later in this preamble under the heading of *COST*.

BCCA asserted that the NO_x SIP point source rule proposal preamble lacks valid, current, and adequate scientific and technical support for the proposed NO_x reduction targets. BCCA asserted that there is no discussion indicating the use of actual industry or vendor retrofit experience which would otherwise precede a determination that the proposed NO_x reduction target is broadly achievable for all point sources categories, and that the commission failed to take the worldwide lack of retrofit experience into account when setting the proposed emission limits. BCCA asserted that there is no discussion or

consideration of design and implementation timing issues, which will impact the technological feasibility of the required technology applications.

Achieving the point source NO_x standards requires the combined use of combustion modification controls and flue gas clean up controls on the majority of large combustion units to achieve approximately 90% reduction. The adopted NO_x reduction targets for utility boilers, gas turbines, industrial boilers and heaters above 40 MMBtu/hr heat input are based on the combined application of combustion modifications and flue gas controls. The estimates of percentage reductions achievable with these technologies applied separately was laid out in the preamble of the proposal to this rulemaking, in the table "Subcategories - Point Source Potential NO_x Emission Reductions by Subcategory for Houston/Galveston Nonattainment Area Counties." (See the August 25, 2000 issue of the *Texas Register* (25 TexReg 8480 - 8482).) The combined capabilities of the technologies in most cases exceed the target specifications and will allow for meaningful choices in the degree of application of each one.

The capabilities of combustion modifications are well documented in the literature, including the NO_x control literature cited in the rule cost note section of the preamble. 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, and 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 adopted specifications. In fact, one vendor has provided several dozen retrofits, primarily on gas-fired boilers in commercial service today, achieving levels of nine ppm or less. 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, 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.

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 a question. Further, the distinctions between new and retrofit applications involve issues of cost rather than technical feasibility.

The literature cited in the preamble 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 this issue of the *Texas Register*, 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.

The implementation schedule and the technical feasibility have been analyzed separately in this adoption preamble in order to show as clearly as possible the reasoning the commission used in adopting the ESADs and in developing the compliance schedule. The commission has tried to use the term technical feasibility in a sense that does not depend on the schedule. What is technically feasible is a function of the state of current engineering practice. The appropriate schedule for applying the technically feasible controls is a function of the practicability (or difficulty) of a certain rate of application. In other words, control measures which are technically feasible

remain so, but there needs to be a feasible schedule to apply them. Responses to comments concerning the compliance schedule are discussed in detail later in this preamble under the heading of *COMPLIANCE SCHEDULE*.

BCCA, Equistar, Goodyear, Lyondell, PECO, and TPIEC stated that although technology has advanced in recent years, there is no one demonstrated, commercialized, retrofit technology application today to achieve the 90% NO_x reduction target for the point source category. BCCA stated that there are other steps that must be taken to achieve the 90% reduction target, such as wholesale replacement of sources, consolidation of sources to reduce fuel firing, and shutdown of marginally economic equipment and plants. BCCA stated that it does not believe such steps are technologically based emission control standards.

The commission agrees that there is no one demonstrated, commercialized, 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. The commission disagrees that the standards are not technologically based. As discussed in several responses in this section, 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 the SCAQMD, because a stream of new permits is issued at lower rates after a new level of NO_x is demonstrated. The commission agrees that 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.

BCCA, Lyondell, and Equistar stated that post-combustion NO_x reduction retrofit controls (e.g., SCR) have not been demonstrated to achieve the desired low level of NO_x emissions envisioned by the proposal. Dynegy stated that because SCR does not have a demonstrated performance history in many applications, it is questionable whether SCR represents a practical and feasible method of control. Dynegy said there is no scientific basis to assert that SCR can consistently achieve the reduction levels set forth in the proposal.

Where it has been required by regulation, such as VCAPCD Rule 59, SCR has been demonstrated to achieve the lowest level of NO_x emissions envisioned by the proposal, 0.01 lb NOx/MMBtu. The commission agrees that SCR alone is not sufficient. The lowest levels of NO_x ESADs are based on the Tier III approach of combining combustion modifications (Tier I) and flue gas cleanup (Tier II), rather than on Tier II alone. SCR is a versatile, demonstrated retrofit technology expected to be used for most of the larger industrial boilers and process heaters. SCR is capable of reducing 90% or more from most combustion exhaust streams, but like any other technology, is not ideally suited for all applications. Combustion controls are developing dynamically, achieving teen and even single digit NO_x ppm in a growing number of applications.

Although the number of SCR retrofits is expected to be unprecedented, the total number of SCRs used will depend on the extent to which combustion controls approach the 8 ppm and 12 ppm ESADs for large and medium units, respectively, and the extent to which they exceed the 30 ppm ESAD for most small units. Similarly, SCRs will be downsized for some units because combustion controls will bear more of the reduction.

BCCA stated that both combustion control improvements and post combustion retrofit controls have technological limitations that reduce their potential effectiveness in achieving the desired emission reduction targets. BCCA stated further that retrofit combustion controls (e.g., low-NO_x burners) will result in a decrease in combustion unit capacity (i.e., de-rate) in up to 15% of the technology applications.

BCCA did not explain how it concluded that retrofit combustion controls (e.g., low-NO_x burners) will result in a decrease in combustion unit capacity (i.e., de-rate) in up to 15% of the technology applications. The commission believes that the combined capabilities of Tier I and Tier II technologies will operate in tandem to minimize these additional costs.

BCCA stated that the proposed emission limits will be unachievable by combustion retrofits for many sources and will require extensive implementation of SCR on an unprecedented and untested scale.

The commission agrees that the number of SCRs required will be unprecedented. This is not the same as being untested. As described elsewhere in this preamble, SCR is one of many tested and

proven technologies available to reduce NO_x emissions.

BCCA stated that in retrofit applications, there are many engineering and design uncertainties that must be addressed including achieving the desired NO_x performance, assuring manufacturing capacity is maintained, and assuring that operating productivity and reliability is maintained.

The commission agrees that these are some of the key engineering and design uncertainties that must be addressed in designing NO_x retrofits.

BCCA and TCC stated that in post-combustion control technology retrofit applications, there are many factors that can reduce not only NO_x performance, but also process unit capacity, equipment operating productivity, and equipment reliability. BCCA and TCC also stated that in many retrofit applications, SCR cannot simply be placed at the end of the flue-gas handling system, but must be designed and located in the correct temperature zone of the flue-gas handling system to ensure proper operation. BCCA stated that the lower temperature limit in the design of the low-temperature SCR systems is 300 degrees Fahrenheit. BCCA stated that units designed specifically for the transfer of heat to process streams (or to capture exhaust gas heat, in the case of duct burners) often have stack exit temperatures below 300 degrees Fahrenheit. BCCA stated that unless space is available in the proper temperature zone of the heat recovery system, major system modifications must be made to accommodate the SCR retrofit and that in some installations there can be significant engineering obstacles to changing the design of the heat recovery system while maintaining system efficiency.

The commission agrees that compliance with the ESADs will be technically challenging. However, as described elsewhere in this preamble, the adopted ESADs are technically feasible. The commission notes several low-temperature SCRs are referenced as 250 degrees Fahrenheit applications.

BCCA stated that the addition of the SCR reactor to the flue gas path will increase pressure drop, which will reduce the firing rate if the loss is not compensated for through the addition of fans (either larger or new) to duct the hot flue-gas through the SCR catalyst bed. BCCA stated that this will result in additional load on the site infrastructure, both electrical and steam production, as well as reduce the capacity or production rate of the unit.

The commission does not disagree that SCRs add pressure drop, but believes the commenter is overstating the effect for units which have fans. The added pressure drop is a few inches water column. With low-temperature SCR, the pressure drop may be 0.25 inch. According to the 1998 NESCAUM report on utility NO_x control, a heat rate penalty of 0.25% is considered typical for gas-fired boilers (Appendix D) and 0.5% represents the high end of the literature for gas and coal units (page 95). The report also states that of more than 200 utility boiler SCR retrofits performed in Europe, Japan, or the United States, none required conversion from forced draft to balanced draft design (pp. 57 - 58). The report indicates that stand-alone SCR designs can be engineered for low system draft losses more easily than in-duct designs, but depending on the additional ducting distance, there may not be a net improvement in draft loss. Long runs of duct work could require new or upgraded fans. Typically, the additional pressure drop from SCR

retrofit is not large enough to require new or upgraded fans. An exception to this is natural draft refinery heaters, which do not have fans.

BCCA stated that it identified less than two dozen SCR retrofit applications in the United States, compared with the 1,800 potential applications expected under the proposed rules. BCCA stated that this very limited retrofit experience would not even qualify SCR as a maximum achievable control technology (MACT) standard for air toxics and is therefore not sufficiently broad for industry to apply and extend confidently across all the regulated sources in the HGA under RACT standards.

There are more than two dozen SCR retrofit applications in the United States. The Institute of Clean Air Companies, an organization based in the United States, has identified more than 500 SCR installations worldwide on a variety of units, many of which are similar to those in HGA and very many of them retrofit applications. The challenges of retrofits in HGA will be similar to units which have already been retrofitted with SCR. The EPA bases MACT standards on its determination of the best performing 12% of existing sources for each particular source category and, significantly, this is regardless of the status of the emission controls as grassroots or retrofit. Whether or not existing SCR applications in the United States are numerous enough in any particular source category for the EPA to determine that they represent the best performing 12% of existing sources for that source category is not relevant to the selection of ESADs. The commenter's position implies that a particular control technology is technically feasible only when there are sufficient retrofit installations of that specific control technology to represent greater than some percentage of the existing sources. As noted earlier, technology is replicable, so in a

true sense, the first successful SCR project was sufficient to demonstrate its technical feasibility. Also, installation of a control technology at a source in one source category often can be "transferred" to other source categories. In addition, the commission notes that the ESADs do not represent RACT, but instead were developed in order for HGA to achieve attainment with the ozone NAAQS.

BCCA, Dynegy, Equistar, Goodyear, and Lyondell stated that SCR has been successfully designed and applied in many new boilers, heaters, and turbines, achieving up to a 90% reduction of NO_x, but that the experience in application of SCR in retrofit applications of existing combustion units is very limited, and in some combustion applications has never been attempted. BCCA, Equistar, Goodyear, and Lyondell stated that the level of NO_x reductions achieved in retrofit applications can vary due to the non-optimum design and operating conditions of the combustion source, such as flue-gas temperature, fuel composition (e.g., sulfur content, ash, etc.), and furnace configuration. BCCA stated that the application of post-combustion control technology in retrofit applications must be carefully engineered on a case-by-case basis and, in some cases, non-optimum equipment and operating conditions will limit the overall control device effectiveness. BCCA stated that if SCR is applied in under less than optimum design and operation conditions, the NO_x control efficiency will drop below the commission's assumed control efficiency range of 85 - 90%. BCCA asserted that the commission has not adequately addressed this issue.

The commission agrees that SCR has been successfully demonstrated to achieve a 90% reduction of NO_x from combustion flue gas streams. The commission also agrees that 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 the factors cited will affect the practice of SCR retrofits in HGA. Retrofits can be expected to be harder 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%. Therefore, the average SCR reduction requirement will need to be significantly less than 90%.

Dynegy, Goodyear, and PECO stated with properly designed and operated combustion units using new ultra-low NO_x burners, NO_x reductions in the range of 60 - 75% are technologically achievable, but that combustion controls cannot meet the proposed 90% reduction, thus requiring SCR.

As noted in the rule proposal preamble, 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 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).)

TECHNICAL FEASIBILITY - UTILITY BOILERS

BCCA, Entergy, and REI stated that the proposed emission specifications for utility boilers exceed levels commonly achieved in practice or are technically infeasible in wide-scale retrofit applications. BCCA stated that although the proposed rate for utility boilers can be achieved in limited applications, the rate is technically infeasible for many gas-fired boilers. REI stated that the proposed rate for gas-fired utility boilers is more stringent than actual emission rates that have been achieved in practice by the majority of utility gas-fired units in Southern California. REI stated that only four of 13 units identified are currently meeting the proposed rate, based on a review of third quarter 1999 emission data, and that the average NO_x emission rate for these 13 units during this period was 0.015 lb/MMBtu. REI acknowledged that the proposed rate has been achieved by several REI units in California, but stated that inherent differences between these units and the majority of units in HGA will make the proposed rate technically infeasible, or economically unreasonable to achieve. REI stated that a fundamental difference is that the REI California units were originally designed to burn fuel oil as a primary fuel while most HGA units were originally designed to fire exclusively natural gas. REI stated that a unit designed to fire fuel oil will generally have a larger furnace volume and lower burner zone heat release rate than a comparable gas-designed unit, and the higher burner zone heat release rates characteristic of HGA gas-fired units suggest higher baseline NO_x rates, requiring a greater degree of

control just to achieve the NO_x emission rates of the Southern California units.

The commission disagrees 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, RECLAIM, for which the underlying emission specification is the 1991 SCAQMD Rule 1135 emission standard of 0.15 lb NO_x/MWh. This output standard is approximately equal to a heat input standard of 0.015 lb/MMBtu. REI stated that only four of 13 boilers they identified in Southern California are below the ESAD and that the average of the 13 boilers is 0.015 lb NO_x/MMBtu. Four of the 13 boilers REI identified, Ormond Beach 1 and 2, and Mandalay 1 and 2, are the only utility power boilers subject to the VCAPCD 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 REI. The data REI supplied in their comments indicate that the MW weighted average emission rate for these four boilers is 0.0085 lb/MMBtu, which is comfortably below the ESAD. Three of these boilers are among the four which operate below the 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 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 REI 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 REI boilers would produce somewhat higher levels of NO_x. This would not mean that achieving the ESAD is technically infeasible. 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 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 the NESCAUM report 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. The combination of combustion control and SCR is technically capable of achieving the gas utility boiler ESAD.

Concerning gas-fired utility boilers, Entergy stated that the units in the NESCAUM report cited in the rule proposal preamble represented an 85% NO_x reduction (i.e., from 0.20 to 0.030 lb/MMBtu) and asserted that the proposed limits for gas-fired utility boilers are technically infeasible due to the "significant incremental expense of controlling by 95% (to 0.01 lb/MMBtu)."

The commission disagrees with the commenter. The actual performance data referenced in the previous response clearly indicates that the selection of 85% reduction in the NESCAUM cost evaluation spreadsheet was not meant to illustrate the technical limits of SCR. Cost and technical feasibility are two separate issues. Whether or not a control technology or emission specification for a given source category will have a higher (or lower) relative cost than that of any other is not relevant to whether that control technology or emission specification is technically feasible. The commission notes that the ESADs do not represent RACT, which by definition takes cost into account. Instead, the 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. 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.

BCCA and REI stated that the proposed emission specification of 0.030 lb/MMBtu for coal-fired boilers is well below the NO_x emission rate currently achieved in practice by any coal-fired unit in the world and that there is no operating experience at this level, or even approaching this level, to demonstrate

that the proposed rate can be achieved or maintained by the affected units in HGA on a continuous basis. REI stated that the primary issues include the lack of SCR experience on Powder River Basin (PRB) coal and the ability to obtain proper mixing of ammonia reagent with dilute concentrations of NO_x while maintaining ammonia slip below two ppm to prevent equipment fouling. REI stated that another obstacle is the ability to obtain completely uniform mixing of the ammonia reagent with NO_x in the flue gas. REI stated that in SCR applications with high inlet NO_x emissions, uniform mixing of ammonia and NO_x is not critical since there is sufficient NO_x to react with any excess ammonia. REI stated that its W. A. Parish coal-fired units are the lowest NO_x emitting units in the United States to be retrofitted with SCR and that as a result the SCR inlet NO_x level will be extremely low (e.g. 20 ppm), making the ammonia-to-NO_x distribution critical. REI stated that while it is paying significant attention to the placement of the ammonia injection grid and the design of the ductwork and static mixers to insure the best possible distribution, maintaining the proper ammonia-to-NO_x distribution under varying operating conditions (i.e. changing load, fuel switches, etc.) may be impossible. REI stated that increasing the ammonia injection rate to improve NO_x reduction will mean exceeding the two ppm ammonia slip target (or ten ppm regulatory limit) unless near perfect mixing is achieved. REI commented that the two ppm target is designed to minimize the formation of ammonium bisulfate and subsequent fouling of downstream equipment (e.g. air heaters) and the contamination of recyclable flyash.

The commission agrees with REI's analysis of the numerous challenges in achieving the design emission specifications for the four coal-fired utility boilers in HGA. The commission has adopted the 0.030 lb/MMBtu ESAD for this category because the reductions are necessary for the SIP and

because this level is technically feasible in the commission's analysis, based on the literature and discussions with SCR vendors. REI has awarded a contract for construction of SCRs on its four coal-fired boilers with an emission specification of 0.030 lb NO_x/MMBtu, which supports the commission's view that the technology has the capability to achieve this level.

Enron asserted that the less stringent limit for coal-fired utility boilers, as compared with gas-fired utility boilers, discriminates against these cleaner burning gas-fired units.

Although the coal-fired limit is numerically less stringent, the coal and gas limits require similar degrees of reduction technology to be applied. The coal-fired utility boiler ESAD is probably designed closer to the limits of technical feasibility than the gas-fired utility boiler ESAD.

REI suggested an alternative NO_x emission reduction plan for REI that it said would achieve an 86% NO_x reduction (88% annual NO_x reduction) at a capital cost savings of over $200 million as compared to the proposed emission specifications.

While the commission appreciates the magnitude and cost of the commenter's NO_x reduction efforts which are currently being implemented, the commission adopted the ESADs for EGFs as proposed because anything less would jeopardize the approvability of the attainment plan, and because the proposed ESADs for EGFs are technically feasible, as described elsewhere in this preamble.

Calpine and Enron suggested that the emission specifications for EGFs should be output-based. Calpine and Enron stated that the proposed input-based standards give less efficient units higher allowances than more efficient units, while output-based standards would provide an incentive for less efficient units to optimize their operations, reducing fuel consumption and thereby reducing NO_x emissions.

With existing equipment there is only limited ability to significantly improve operating efficiency. In cases where it is feasible to retrofit to upgrade efficiency, the resulting twin advantages of reduced production costs and reduced emissions for the same production level will be enjoyed under a cap and trade program regardless of whether allowances are based on historical input or output. The existing standards, monitoring systems, and data management programs for utilities are heat-input based. Creating a different basis for a standard would be confusing and would unnecessarily complicate emission monitoring and reporting. In addition, the efficiency penalties associated with the required post-combustion NO_x controls would penalize the units if the standards were expressed on an output basis. The commission believes that output-based standards would provide little benefit for existing units and would needlessly complicate the existing regulatory procedures in place. The commission has made no change in response to the comment.

TECHNICAL FEASIBILITY - AUXILIARY BOILERS

BCCA and REI stated that the proposed emission specification of 0.010 lb/MMBtu for auxiliary boilers is technically infeasible since auxiliary boilers typically operate for extended periods at minimum loads with infrequent operation at high loads. BCCA and REI stated that for most of the operating schedule,

flue gas temperatures will be well below conventional SCR operating temperature requirements, thereby preventing effective NO_x reduction.

The commission agrees that SCR is not an appropriate choice for auxiliary boilers because they infrequently operate at high loads. The infrequent operation at high loads means that the cost effectiveness will be extremely poor, regardless of whether SCR is technically infeasible in this application. The commission has added an alternative emission specification as new §117.106(c)(4) for auxiliary boilers, utility boilers, and stationary gas turbines based on Tier I controls. The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for these units 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. This standard is achievable and is consistent with existing permit limits. As noted later in this preamble in the *DEFINITIONS* section, the commission has revised the definition of auxiliary steam boiler in §117.10(3) to clarify that 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.

TECHNICAL FEASIBILITY - GAS TURBINES

PECO stated that the use of SCR on simple cycle peaking turbine has not been adequately demonstrated. PECO stated that it knows of only four SCR installations on peaking gas turbines, and that a compressor station in California has requested relief from its emission limits due to difficulties in utilizing SCR. PECO stated that combined cycle units operate at a low exhaust gas temperature and typically operate at a high utilization factor with a low number of startups per run hour, while simple

cycle units have a high exhaust gas temperature and typically operate with frequent startups per run hour. PECO stated that high exhaust gas temperatures and frequent thermal cycling contribute to premature failure of a catalyst bed, and that during each startup cycle the SCR's NO_x control efficiency is reduced until it reaches the necessary operating temperature perhaps 15 to 20 minutes into the startup sequence. PECO suggested that NO_x emission specifications for simple cycle gas turbines be set at 0.033 lb/MMBtu and 0.015 lb/MMBtu for combined cycle gas turbines, because SCR has been proven in that application. Solar Turbines stated that "SCR systems may not be technically, operationally, and/or practically feasible for many of the applications as (approximately) 85% of the potentially affected units are in mechanical drive/compressor applications. Historically these applications, due to their high exhaust temperature, are not appropriate applications for an SCR and for which LAER levels have been 8 - 42 ppm."

The commission agrees with PECO that the adopted ESAD is demonstrated in combined cycle applications. However, the commission also believes that SCR is sufficiently demonstrated in high-temperature applications to justify the ESAD in simple cycle applications. The compressor station in California to which PECO referred had a high-temperature SCR catalyst installed in 1990 which did not perform adequately. Since that time, the company has installed a new SCR catalyst from a different vendor and has met the performance levels required by the source's permit. This vendor indicates that there are a dozen installations of high-temperature SCR on simple cycle turbines in the United States with NO_x control down to several ppm. One packager of SCR systems has said that there are many high-temperature SCR orders being placed for simple cycle utility operation in summer 2001. According to this packager, the high temperatures

and frequent thermal cycling are expected to shorten the life of the catalysts to two or three years, based on 2000 hours per year of operation. Although catalyst replacement cost may be higher relative to a conventional SCR, the peaking turbines need to be well controlled because they operate during periods of peak electric demand, mostly the hot summer days which are conducive to ozone formation. The turbines with the highest exhaust temperatures may add dilution air or water to lower the exhaust temperature to improve SCR performance. Catalytic combustion may become a technology alternative to SCR in the 2004 - 2005 time frame for the type of gas turbines that PECO has proposed to construct. The commission has not changed the ESAD in response to these comments.

BCCA and REI stated that the proposed emission specification of 0.015 lb/MMBtu (approximately four ppm) is well below the levels included in SCAQMD Rule 1134 of approximately 9 - 15 ppm and approaches LAER for new installations. BCCA stated that it reviewed worldwide retrofit experience for gas turbines and that it found no equipment designed for and meeting the proposed emission standards. BCCA asserted that the commission failed to take this worldwide lack of experience into account when setting the proposed emission limits. BCCA and Dynegy noted that the current limit for gas turbines in HGA is 42 ppm NO_x as of December 31, 1999. BCCA and Dynegy stated that there are four types of NO_x control technologies for gas turbines: wet combustion controls (steam or water) that can get many models down below 42 ppm; combustion hardware controls (known as dry low-NO_x burners (DLN) for most models) that are available for many models to get the NO_x ppm down to the mid-twenties or low-teens; SCR to get the NO_x ppm down to below the ten ppm level; and a combination of SCR and combustion controls to possibly achieve a NO_x ppm in the mid-single digits.

The adopted 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 adopted 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 adopted 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 adopted 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 adopted 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. It 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.

BCCA stated that two of the five major worldwide providers of gas turbines have never performed a retrofit application of post-combustion control technology.

The gas turbines in HGA were primarily built by three companies, although four other manufacturers have at least one turbine operating in the area. Turbine manufacturers' retrofits

tend to apply to the turbine itself, and each of the three primary builders of the HGA gas turbines have some experience with retrofit of combustion modifications, water or steam injection and dry low-NO_x burners. Post-combustion control technology, such as SCR, would typically be provided by turn-key suppliers of SCR systems packages, who have some experience with gas turbine retrofits as indicated in the previous response.

BCCA noted that gas turbines can be found in utility plants, industrial plants, and remote pipeline transmission sites, and stated that each location, and in many cases each machine, has its own unique design and operating conditions that need to be considered when determining the feasibility of a particular NO_x reduction technology. BCCA stated that gas turbines in HGA vary by manufacturer and model, and the manufacturer must develop the technology for each specific engine model. BCCA stated that as an example, steam and/or water and low-NO_x combustion hardware is not currently available from some manufacturers, narrowing the owners' technology options. BCCA and REI stated that the ESAD for gas turbines cannot be reasonably achieved in retrofit applications where after-market water injection or DLN firing systems are not available, where space constraints impact SCR design, or where flue gas temperatures preclude SCR altogether. Solar expressed similar concerns and provided a table attachment with their comments which summarized availability and existing operation of applications of DLN, water, and SCR controls on their turbines.

Turbine manufacturers indicated during the development of the currently applicable 42 ppm NO_x RACT limit that combustion modifications, with either after-market water injection or DLN, were feasible on all models of gas turbines above ten MW known to be in operation in HGA. Water or

steam injection has widespread retrofit applicability, in contrast to the limited applicability of retrofit DLN, the feasibility of which is dependent on the design features of specific models. Water injection may be provided by an aftermarket supplier, but the availability of DLN depends on the original turbine manufacturer. The costs for design or installation of water or steam injection controls for a few of the older turbine models in HGA may have caused alternative RACT compliance strategies to be used. These issues relate to cost rather than technical feasibility. In Solar's table, either water injection or DLN are available as Tier I controls on each model line, except for the smallest line, the Saturn 10s. The Tier II control, SCR, is listed as an option for each model type. As indicated in a response following this one, the commission has adjusted the ESAD in response to the information received that Tier I controls are not feasible for the Saturn 10s. Space constraints will affect SCR design, but the relocation of the heat recovery section to install a conventional temperature SCR is a demonstrated approach and therefore technically feasible. In addition, low-temperature SCR is capable of reducing or eliminating the need to relocate heat recovery equipment. Examples of low-temperature SCR providing between 90% and 95% reduction are listed in *Low-temperature SCR Expedites Plant Retrofits for NO_x Reduction* (Gas Turbine World, July/August 1997 issue). One of the examples is in HGA, a 90% reduction on a 325 degrees Fahrenheit exhaust stream from an Allison 501-KB5 gas turbine located in Pasadena, which is part of the HGA ozone nonattainment area. With regard to flue gas temperatures precluding SCR altogether, as discussed in the first response in this section, the commission believes that high-temperature SCR is technically feasible for simple cycle gas turbine exhausts.

BCCA, GPA, and Kinder Morgan stated that the use of efficient low-NO_x combustion technologies should be applied on gas turbines to achieve a 60 to 75% reduction to a 42 to 25 ppm NO_x emission levels, but without use of SCR. TCC suggested that small turbines should only be required to make burner improvements. Enterprise stated that it does not have the option to replace its 36 gas turbines with a smaller number of larger units since each installation is unique for its turbine compressor or turbine generator package. Enterprise suggested that NO_x emission specifications for gas turbines be set at 0.030 lb/MMBtu (approximately nine ppm) for large turbines and 0.15 lb/MMBtu (approximately 42 ppm) for small turbines.

The commenters are recommending Tier I control levels for their gas turbines. The gas turbines are the second largest category of point sources in HGA, and Tier III standards are required for a successful attainment demonstration. The previously referenced plant in Pasadena which is achieving a 90% reduction using low-temperature SCR on an Allison 501-KB5 gas turbine indicates both the technical feasibility and economically reasonableness of Tier II controls for small gas turbines. The commission has made no change in response to the comments.

Kinder Morgan expressed concerns that application of SCR to gas turbines in gas transmission service would encounter the load following problems experienced on lean-burn IC engines in similar gas transmission service.

The commission believes that the current generation of SCR operating controls designed for load following applications will address Kinder Morgan's concerns. Conversion to electric motors is

also a compliance option.

Kinder Morgan stated that the commission should reconsider the emission specifications for gas turbines less than 1.0 MW and establish emission specifications based on existing, proven combustion modification technology. Solar said that water injection is not available on their 1,000-1,300 hp gas turbines.

Solar offers neither DLN or water injection on their less than 1.0 MW gas turbines, the older Saturns. They do not currently offer water injection on the Saturns as a result of an unsuccessful application in California. In response to information provided by Solar that the water injection problem with the Saturns relates to physical limitations of the small combustor, the commission modified the ESAD for existing turbines below 1.0 MW (1,340 hp) to reflect the application of Tier II controls. The adopted ESAD for gas turbines with a rating below 1.0 MW and placed into service on or before December 31, 2000 is 0.15 lb NO_x/MMBtu, which is very similar to the 0.5 g/hp-hr limit for lean-burn gas-fired IC engines. This limit could be met by SCR and would leave water injection as a possibility if the technical issues can be overcome.

BCCA, Kinder Morgan, Solar Turbines, and TCC commented that small gas turbines (less than 10 - 20 MW) are often used with duct burners to generate thermal heat recovery efficiently. TCC stated that many small turbines, some with duct burners, are involved with heat recovery so they cannot efficiently be replaced with electrically driven turbines, and that if heat input had to be drawn from another source, then that source will emit additional NO_x.

The basis for the gas turbine ESAD is not replacement with electric drive, although this approach could be used to comply for some mechanical drive applications. Sources with heat recovery can retrofit SCR in the conventional temperature zone for SCR or apply low-temperature SCR at the back end.

BCCA stated that requiring a 90% reduction from the current 42 ppm NO_x level, which it asserted can only be achieved today with SCR, skips the DLN option. TCC said that the commission should encourage the use of burner improvements to control small stationary gas turbines. Solar Turbines stated that some older turbines cannot be retrofitted with DLN systems. Solar provided an inventory of its machines operating in HGA which indicated DLN is not feasible on half of them, and of those for which it is technically feasible, 34% would require power uprating with significant costs, 11% are using DLN, and 5% are retrofittable with DLN without an upgrade to increase the power rating.

The commission agrees that DLN, with varying capabilities between 9 - 42 ppmv, cannot achieve a 90% reduction from the current 42 ppm level. Contrary to being a skipped option, the DLN retrofit option was used on some units to comply with the 42 ppm NO_x RACT emission specification. Solar's comment indicates that DLN may well be attractive for a few additional machines in providing the combustion modification step, but flue gas cleanup would still be required to meet the adopted ESAD. The potential for increased availability of DLN is limited because the original turbine manufacturer faces high development costs based on unique design features of specific models, of which there may be few in operation and even fewer subject to stringent emission specifications. Even if a new DLN retrofit design were successfully engineered,

it would have to compete with more effective retrofit technologies in the market place. NO_x control technologies in operation today that are more effective than DLN include high-temperature, conventional-temperature, and low-temperature SCR, NO_x adsorber catalyst, and catalytic combustion.

BCCA stated that the combustion control technology for many models of gas turbines is still being improved and new technologies, such as catalytic burners, are being developed but are not yet in commercial application. BCCA stated that catalytic burners, an emerging technology for new gas turbines, have the potential to reduce NO_x levels as low as SCR systems with no ammonia slip, and will likely be significantly lower in cost. BCCA also stated that downtime for retrofits will be less compared to an SCR installation, operations and maintenance costs are also expected to be much lower, and there will be no additional back pressure and resultant efficiency loss typically experienced with SCR retrofits. BCCA asserted that the proposed emission specifications for turbines may preclude the use of emerging combustion technologies that may achieve SCR-like NO_x reduction performance levels without the potential environmental impact of ammonia. Dynegy commented similarly, citing more specifically the possibility of avoided risk from transport and storage of ammonia, spent catalyst, and increased carbon dioxide (CO_2) emissions. TCC said that the commission should encourage the use of burner improvements to control small stationary gas turbines.

Catalytic combustion for gas turbines is an attractive technology for the reasons cited by the commenters. There are a number of time consuming steps necessary to implement catalytic burners, including obtaining development capital for burner design for specific turbines,

engineering, pilot testing, and demonstration in commercial operation. These steps must be repeated for each type of turbine burner. Several years of lead time are necessary before commercial operation can begin. Because of these steps, it appears that catalytic combustors will be first applied to new rather than existing gas turbines and only a few gas turbines will operate with this technology by 2005. Nonetheless, stringent gas turbine emission standards such as contained in this rulemaking provide a strong impetus to commercialize catalytic burners. The structure of the adopted rule also provides incentives to innovative technology. First, the market approach values overcompliance with the standards. Second, emission compliance is annual for most sources. Higher emissions which may occur with a new technology because of start-up bugs likely occur for a short time. Annual averaging reduces the significance of short time values. Innovative technologies such as catalytic burners which may offer performance better than the standard can particularly benefit from the market approach and long term averaging.

TECHNICAL FEASIBILITY - ICI BOILERS AND PROCESS HEATERS

BCCA stated that the proposed emission reductions for industrial boilers go well beyond current BACT for new sources and approach or meet the most stringent emission standards envisioned for new sources, LAER. BCCA stated that in most cases, the proposed emission standards for ICI facilities exceed the SCAQMD emission limitations.

The 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.

In the SCAQMD, new boilers are being permitted for NO_x levels essentially equivalent to the lowest boiler ESAD of 0.010 lb/MMBtu (eight parts per million by volume, dry basis (ppmvd) at 3% oxygen, annual average). The SCAQMD BACT website at http://www.aqmd.gov/bact/AQMD_BACT_Determinations.htm includes information on three boilers in sizes of 110, 78.6 and 48.6 MMBtu/hr. They are permitted at a limit of nine ppmvd at 3% oxygen, on a 15-minute average compliance time. For the boilers between 40 and 100 MMBtu/hr, nine ppm is 25% lower numerically than the ESAD of 0.015 lb/MMBtu (12 ppmvd at 3% oxygen). The 15-minute average of the SCAQMD permits represents effectively an even greater difference than the annual ESAD. Even for the 110 MMBtu/hr boiler, nine ppmvd on a 15-minute average is at least as stringent as the corresponding eight ppmvd ESAD, considering the difference in effective stringency between a 15-minute and annual average compliance period. The commission notes that these permit limits are based on Tier I controls, ultralow-NO_x burner technology, rather than Tier II flue gas cleanup, or the combination, Tier III.

In the SCAQMD, new process heaters are being designed for lower NO_x levels than the lowest process heater ESAD of 0.010 lb/MMBtu (eight ppmvd at 3% oxygen). The SCAQMD BACT website at http://www.aqmd.gov/bact/AQMD_BACT_Determinations.htm includes information

on the following process heaters and limits: 460 MMBtu/hr hydrogen reformer furnace, seven ppmvd at 3% oxygen; 764 MMBtu/hr hydrogen reformer furnace, five ppmvd at 3% oxygen; 653 MMBtu/hr hydrogen reformer furnace, five ppmvd at 3% oxygen; 50 MMBtu/hr refinery heater, seven ppmvd at 3% oxygen. The refinery heater is permitted 42% lower than the corresponding process heater ESAD of 0.015 lb/MMBtu (12 ppmvd at 3% oxygen). The controls are Tier III, using low-NO_x burners and SCR for flue gas treatment. The SCAQMD heater permits set a three-hour averaging period, significantly more stringent than the annual average of the ESADs.

BCCA stated that it reviewed worldwide retrofit experience for ICI boilers, process heaters, and furnaces (general application and steam cracking furnaces), and that it found no equipment designed for and meeting the proposed emission standards. BCCA asserted that the commission failed to take this worldwide lack of experience into account when setting the proposed emission limits.

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. Most districts in California set boiler and process heater retrofit requirements at this level for ICI boilers and process heaters above 5 MMBtu/hr, whereas SCAQMD and VCAPCD set the applicability levels at 2 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 adopted HGA specifications is a function of regulatory standards, rather than technical feasibility. Regulations set emission levels, and the HGA NO_x specifications 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.

KTC, TCC, and an individual commented on the proposed NO_x emission specification for boilers and process heaters in §117.206(c), and stated that boilers or process heaters which utilize process waste gas containing chemical-bound nitrogen as a source of fuel or combustion air should receive a multiplier for compliance with the emission specifications for a variety of reasons. KTC and TCC stated that utilizing process waste gas as fuel in boilers provides both useful extraction of energy, as well as pollution control. KTC and TCC stated that because NO_x limits may not be achieved while burning waste gas, industrial sources will make large capital expenditures for flares and actually result in an increase in NO_x emissions. KTC and TCC stated that the new flares will burn fuel, creating NO_x, and the boilers will have to use more natural gas to replace the lost waste gas fuel. KTC and TCC stated

that process waste gas compounds containing chemical-bound nitrogen may have a high heating value, which has the potential to produce a higher flame temperature than materials that have a lower organic content, thus reducing the chance of meeting proposed NO_x emission specifications. KTC and TCC stated that catalytic reduction of NO_x is not practical as a pollution control solution because of the variability of process waste gas and the likelihood of fouling or poisoning of the catalyst. KTC stated that vendor claim that a 75% NO_x reduction can be achieved with combustion modifications such as low-NO_x burners and FGR, but that two of its boilers utilize low-NO_x burner and FGR, yet do not meet the proposed limits.

The commenters have noted that the rules as proposed create some incentive for circumvention by redirecting dirty fuel streams to flares or other units for which an ESAD has not been established. To prevent such circumvention from resulting in an increase in emissions at non-ESAD units, the commission has added a new §117.206(h) which prohibits the owner or operator of units which utilize liquid or gaseous streams containing chemical-bound nitrogen as a source of fuel or combustion air from circumventing the emission reduction requirements by directing these streams to flares or other units which are not subject to an ESAD in §117.206(c), unless the unit which receives the chemical-bound nitrogen stream is opted into the Chapter 101 mass emissions cap and trade program, and NO_x emissions from this opt-in unit are determined using a CEMS or PEMS which meets the requirements of §117.213(e) or (f), or through stack testing which meets the requirements of §117.211(e).

TECO commented that it operates two “District Energy Plants” which furnish steam and chilled water

to a variety of medical buildings, including four gas-fired boilers rated at over 100 MMBtu/hr heat input which would be subject to the proposed 0.010 lb/MMBtu emission specification of §117.206(c)(1)(A). TECO stated that future growth could result in the building owners installing individual boilers rated at less than 40 MMBtu/hr, which would be limited to 0.036 lb/MMBtu, and that the boilers would produce less than ten tpy and therefore would not be subject to the proposed Chapter 101 mass emissions cap and trade program. TECO also noted that these smaller boilers would not have to install CEMS. TECO suggested setting a NO_x emission specification of 0.030 lb/MMBtu for "District Energy Plants" with gas-fired boilers rated at over 100 MMBtu/hr heat input and stated that this would be more cost-effective than meeting the proposed 0.010 lb/MMBtu emission specification, but would result in greater emission reductions compared to multiple smaller boilers.

The 0.010 lb/MMBtu emission specification may be achievable with Tier I controls for the single burner boilers above 100 MMBtu/hr that TECO operates. The emission specification is appropriate for natural gas fired boilers in this size range. However, TECO raises a valid point about the possibility of adding additional smaller boilers under separate control at different sites, at the higher 0.036 lb/MMBtu ESAD. The net result would be higher emissions than if TECO were to provide this expanded capacity. The medical centers are projected to grow, and the cap would effectively prevent TECO from providing the additional chilled water requirements to accommodate this growth at the lower emission rates from their larger boilers. One option would be to provide incentives for larger, cleaner facilities by allowing a District Energy Plant to add to its activity level when a firm contract for energy is arrived at from a new player who wouldn't otherwise be subject to the cap and trade program. However, the commission believes it may be

more appropriate to address any potential increase in emissions from small sources outside the cap by targeting those sources directly (for example, by lowering the threshold for the cap and trade program) in potential future rulemaking.

BP, Equistar, Lyondell, and TCC suggested that the proposed emission specification for process heaters in §117.206(c)(8) should be revised to add a separate emission rate for pyrolysis reactors (ethylene cracking furnaces) because they are unaware of technology which would enable pyrolysis reactors to meet a 0.010 lb NO_x/MMBtu emission specification. BCCA stated that there has been no retrofit post-combustion control application on ethylene pyrolysis furnaces anywhere in the world. Equistar, Lyondell, and TCC stated that a pyrolysis reactor is a combustion device where ethylene and propylene are produced from feed stocks such as ethane, propane, butane and naphtha, with highly endothermic thermal cracking reactions that require significant heat input to start and complete the reactions. BP, Equistar, Lyondell, and TCC stated that a pyrolysis reactor is different from a typical process heater because of the following: higher firebox temperature, flame temperature (2,200 - 2,300 degrees Fahrenheit), and heat flux (heat transfer per unit of area, Btu/(hour)(square foot)), as flame firebox temperature increases the NO_x production increases; high hydrogen content of olefins plant fuel gas, which further increases flame temperature; highly endothermic reaction that requires higher heat input with high-temperature radiant tubes/coil; high-temperature radiant section-pyrolysis cracking reaction occurs inside radiant tubes with no catalyst; smaller diameter radiant tubes to achieve a shorter residence time (less than one second); coke formed during pyrolysis reaction fouls the radiant tubes that requires periodic cleaning; convection section- highly integrated energy recovery system, higher energy efficiency (90 - 94%); and multi-stream energy recovery achieved (feed pre-heat, boiler feed water,

steam superheating, and mixed feed superheating). Equistar, Lyondell, and TCC also stated that pyrolysis reactor conditions vary more widely than process heater conditions; that different feedstocks and different market conditions affecting optimal reaction severity require different cracking temperatures; and that the complex heat distribution requirements have thus far defeated efforts to reduce NO_x dramatically via ultra low-NO_x burners.

The commission agrees that the ethylene furnaces present a challenge to control, particularly with regard to Tier I controls, because of the factors cited by the commenters. 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 adopted 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.

TECHNICAL FEASIBILITY - FCCU

BCCA stated that it reviewed worldwide retrofit experience for FCCUs, and that it found no equipment designed for and meeting the proposed emission standards. BCCA asserted that the commission failed to take this worldwide lack of experience into account when setting the proposed emission limits. BCCA stated that there is only one commercial application of post-combustion control technology in the United States on a refinery FCCU (one that has just started up in California). BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for FCCUs. BCCA and TxOGA requested that the commission provide the technical justification for the proposed emission specifications for FCCUs. BCCA stated that there is no long-term demonstrated commercial experience in the world to indicate this type of retrofit NO_x standard is achievable for all FCCUs in HGA. BP stated that the proposed emission specification for FCCUs in §117.206(c)(2), ten ppmv at 0.0% O_2 (dry basis), would represent a 95% reduction using SCR at their location. BP stated that they are not aware of technology which would meet this standard. BP stated that some FCCUs with hydrotreated feed typically have an uncontrolled NO_x level of 200 ppmv, and therefore "*may* be able to achieve a 90% reduction across the SCR" to reach 20 ppmv. (BP's emphasis supplied.) BP stated that FCCUs with non-hydrotreated feed may more typically have an uncontrolled NO_x level of 300 - 400 ppmv, and therefore could achieve 30 - 40 ppmv based upon a 90% reduction across the SCR. BP considered these units more similar to coal-fired boilers (0.030 lb NO_x/MMBtu) rather than process heaters (0.010 lb NO_x/MMBtu) since the catalyst "coke-burn" in a FCCU is somewhat comparable to coal-firing in a boiler. BP stated that installation of SCR on an FCCU presents unique challenges, such as potential for flow reversal or other nonroutine operating conditions such as high temperature at the SCR catalyst or excessive carryover of FCCU catalyst into the flue gas

stream. Consequently, BP suggested that the commission allow the facility to permit start-up emissions or accept a demonstration that certain start-up emissions are unavoidable. Phillips 66, TxOGA, and Valero expressed concerns similar to those of BP and stated additionally that sulfur dioxide scrubbers will be required to protect SCR catalysts from poisoning. Valero stated that its refinery does not employ wet gas scrubber technology. Valero suggested that the FCCU NO_x emission specification for refiners that have already committed to install wet gas scrubbers be set at levels consistent with the wet gas scrubbing technology committed to be installed. Phillis 66 and TxOGA also stated that flue gas temperature conditioning with duct burners, an additional NO_x source, will be necessary to make the system viable.

The commission staff used NO_x emission information submitted by refinery representatives to calculate an average concentration of 100 ppm and therefore a 90% reduction would be achieved by an ESAD of ten ppmv. However, there wasn't sufficient analysis of weighted flow rates, so the commission has reevaluated the average concentration using available data and determined a tpd-weighted average of 125 ppmv. Therefore, commission modified the limit to either 13 ppmv or 90% reduction measured either by an upstream/downstream CEMS, or from baseline data approved by the commission. As part of this effort, the commission has accelerated the timetable for installing NO_x CEMS on the FCCU to June 30, 2001 for any FCCU which uses the baseline data approach. This would be necessary to consider actual long term operating data in conjunction with the 1997 emission inventory data used in the SIP, in time for setting the emission allocations. The Tier I combustion modifications that may be available to reduce NO_x include: managing nitrogen in the feedstock, low oxygen operation, or use of low-NO_x combustion

promoters or NO_x removal additives. Low-NO_x promoters and NO_x reduction additives each have been shown to reduce NO_x emissions by more than 50% in commercial operation. With regard to Tier II technology, 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. 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 modification of the FCCU ESAD to either a concentration limit or a percent reduction ensure that this standard is technically feasible.

TECHNICAL FEASIBILITY - BIF UNITS

Solutia, TCC, and Union Carbide stated that the proposed NO_x emission specification of 0.015 lb/MMBtu for BIF units in §117.206(c)(3) is not technically achievable. An individual stated that nearly all liquid-fueled units are equipped with wet scrubbers, and that moisture, particulate, metals, sulfur, and chloride cause significant problems with SCR or selective non-catalytic reduction (SNCR). The individual suggested that the emission specification for units with wet scrubbers should be an 80% reduction. TCC and Union Carbide stated that post-combustion controls will be difficult to maintain due to the inorganics in the fuel, which can deactivate or plug SCR catalysts.

The commission considered the waste streams in the HGA BIFs in response to these comments and

agrees with the commenters 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 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. The commission adopts the 0.015 ppm ESAD for BIFs, if rated greater than 100 MMBtu/hr heat input, because these boilers combust hydrocarbon wastes which do not threaten to reduce the effectiveness of SCR as the flue gas cleanup application.

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. The commission disagrees with the comment that SNCR will be adversely affected by these inorganics, 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.

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 first 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 commission has modified the ESAD for the BIFs rated less than 100 MMBtu/hr heat input. The adopted ESAD

for these units is either an 80% reduction from baseline, or 0.030 lb/MMBtu.

Union Carbide stated that some combustion controls will compromise the intended purpose of BIF units (i.e., disposal of hazardous wastes). TCC and Union Carbide stated that optimization of the firebox for NO_x control may actually begin to coat the catalyst sites and reduce the overall effectiveness of the SCR. TCC and Union Carbide stated that all BIF units are operated with excess oxygen and high residence times and/or high temperatures to ensure complete destruction of organics, and all of these operating techniques are contrary to NO_x formation control technology. An individual stated that there is no commercially-available low-NO_x burner for liquid fuels and that the proposed emission specification in §117.206(c)(3) should not apply to liquid-fueled BIF units.

As noted in the rule proposal preamble, the emission specifications are expected to necessitate flue gas controls on affected BIF units and RCRA incinerators. The commission never intended or expected combustion controls to be used on BIF units and RCRA incinerators to meet the emission specifications. The basis for the higher ESAD for certain BIF units compared to boilers and heaters (those rated above 100 MMBtu/hr) was that combustion controls could compromise the intended purpose of BIF units. (See the August 25, 2000 issue of the *Texas Register* (25 TexReg 8287 - 8292 and 25 TexReg 8480 - 8482).) Although combustion controls were presumed not to be part of the compliance strategy for purposes of rule development, combustion controls are not precluded from being used in practice for compliance with the adopted ESAD for BIFs. Some of the large industrial boilers which are regulated as BIFs may be able to significantly reduce NO_x emissions from gas firing with combustion modifications while retaining the conditions necessary

for proper destruction efficiency while firing liquid hazardous waste. The commission made no changes to the ESADs in response to these comments.

TCC stated that combustion controls for NO_x typically increase the amount of CO generation, but that federal BIF regulations are written to minimize the CO generation since it is an early indicator of the destruction efficiency of the constituents of the hazardous waste used as fuel. TCC stated that 40 CFR 266.102(e)(2)(ii)(A) and 40 CFR 266.104(b) specially call out for a CO limit of 100 ppmv at 7.0% oxygen (dry basis). TCC stated that this is one third of the limit allowed in §117.206(e)(1) when converted to the same conditions. TCC stated that while post combustion controls can also remove CO in addition to NO_x, a higher CO emission rate from the fire box will also mean organics are not being combusted as desired, and organic breakthrough increases as CO increases.

The CO limits are designed to address a pollutant which may increase significantly as an incidental result of compliance with the adopted NO_x limits. Because BIFs and incinerators already have CO limits under regulations designed to ensure destruction efficiency of the wastes combusted, CO limits for these units are not needed in Chapter 117. The commission has exempted BIFs and incinerators from the CO limit of §117.206.

Rhodia stated that the emissions it reported for its BIF unit was based on tons produced and an emission factor as determined by stack testing. Rhodia noted that the proposed emission specification in §117.206(c)(3) is based on the heat input (MMBtu) to the BIF unit and stated that its BIF unit may or may not be classified as a major source, depending on which set of data is used. Rhodia requested

clarification of this issue.

The Rhodia BIF was included in the commission's analysis as a unit which would be subject to the NO_x reduction requirement under the ESAD for BIFs. The heat input for this ESAD is intended to include the total heat value of materials fired in the combustion device rather than just supplemental fuel. The emission specifications of §117.206 apply at major sources of NO_x. For HGA, the definition of "major source" includes any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit at least 25 tpy of NO_x. Therefore, NO_x emissions from all stationary sources or groups of sources are included in determining a "major source" classification. The 1997 emissions inventory also listed a fired heater and boiler in the size range to be subject to ESADs at Rhodia's Houston plant.

Solutia stated that it has three BIF units that are used to control VOC emissions from an air oxidation reaction process, but are classified under RCRA as boilers which burn a hazardous waste. Solutia stated that the NO_x emissions from these units result from burning of natural gas and from combustion of organics containing chemically-bound nitrogen. Solutia suggested that a higher emission limit be specified when incineration of chemically-bound nitrogen occurs, or alternatively, that the NO_x limit should exclude NO_x from incineration of nitrogen-bearing compounds.

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, and 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 (FBN), 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 ESADs were developed from this information and therefore reflect the effects of FBN. NO_x produced by FBN is not any different from NO_x formed by the other formation mechanisms, "thermal" or "prompt" NO_x. Because of this, the presence of FBN does not pose questions of technical feasibility that have not already been considered.

TECHNICAL FEASIBILITY - COKE-FIRED BOILERS

No comments were received on the proposed NO_x emission specification for coke-fired boilers in §117.206(c)(4). This emission specification is adopted without changes.

TECHNICAL FEASIBILITY - WOOD-FIRED BOILERS

Pasadena/Donohue and TPIEC commented on the proposed NO_x emission specification of 0.020 lb/MMBtu for wood-fired boilers in §117.206(c)(5). Pasadena/Donohue stated that one of the wood-fired boilers identified in the rule proposal preamble fires a variety of fuels, including wood, tire-derived fuel (TDF), and wastewater treatment sludge. Pasadena/Donohue stated that nitrogen-

containing resins in the wood fuel can be expected to increase NO_x emissions as compared to gas-fired boilers. Pasadena/Donohue stated that SCR has not been demonstrated in wood-fired boilers or in boilers using wood in combination with other fuels, and stated further that while SNCR has been used on base-loaded wood and combination/wood-fired boilers, it has not been demonstrated on such units with changing loads. Pasadena/Donohue stated that an SNCR installation (not identified) on a wood-fired boiler had been unable to consistently meet its target emission limit and had higher than expected ammonia usage and slip. Pasadena/Donohue stated that combustion controls such as FGR and overfire air have not been demonstrated in full-scale combination/wood-fired boilers. Pasadena/Donohue suggested that the proposed NO_x emission specification be changed to 0.30 lb/MMBtu, consistent with the permit limit for one of the wood-fired boilers identified in the rule proposal preamble. TPIEC submitted a September 20, 2000 National Council of the Paper Industry for Air and Stream Improvement, Inc. (NCASI) memo which stated that the requirement to use SCR to achieve a NO_x emission limit of 0.02 lb/MMBtu and over 90% NO_x removal in a wood-fired boiler appears to be based upon the assumption that SCR is applicable to such boilers in a manner similar to utility boilers firing fossil fuels. The NCASI memo stated that use of SCR technology has clearly not been demonstrated for industrial wood, biomass, or combination fuel-fired boilers, and that the issues pertaining to severe energy penalty and space and logistical limitations need to be addressed. The NCASI memo further stated that achieving high levels of NO_x removal using SNCR technologies on wood-fired boilers also has several limitations, including the key one of installing optimally placed injection points for the SNCR chemical in situations of swinging loads and dealing with potentially excessive ammonia slip and plume opacity problems.

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 disagrees with the comments related to the difficulty of installing optimally placed injection points for SNCR, dealing with swinging loads, and the potential for excessive ammonia slip. These features, in fact, are a routine part of commercial SNCR installations. 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 with the operation of Bowater's SNCR system since it was installed. There are several other commercial applications of urea-based SNCR on wood/biomass fired systems. 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 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 first 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 more representative design goal for dirty fuel streams. The oxidation technologies appears capable of the 90% reductions envisioned by the proposed 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 commission has modified the ESAD for wood-fired boilers to either an 80% reduction from baseline, or 0.046 lb/MMBtu.

TECHNICAL FEASIBILITY - RICE HULL-FIRED BOILERS

No comments were received on the proposed NO_x emission specification for rice hull-fired boilers in §117.206(c)(6). This emission specification is adopted without changes.

TECHNICAL FEASIBILITY - OIL-FIRED BOILERS

No comments were received on the proposed NO_x emission specification for oil-fired boilers in §117.206(c)(7). This emission specification is adopted without changes.

TECHNICAL FEASIBILITY - IC ENGINES

EMA, ExxonMobil, GPA, Kinder Morgan, Pasadena/Donohue, TCC, Texas Eastern, TGC, and TGP noted that sites with a total of 3,000 hp or more must control all engines to meet a NO_x level of 0.17 g/hp-hr. BCCA, GPA, Kinder Morgan, Texas Eastern, TGC, and TGP questioned why stationary IC engines were singled out as a source category for wholesale replacement. ExxonMobil expressed similar concerns regarding replacement of stationary IC engines with electric drive motors. EMA

stated that a stationary gaseous-fueled engine rated at greater than 3,000 hp could meet the proposed limit with advanced SCR, but this control would be costly. GPA, Kinder Morgan, Texas Eastern, TGC, and TGP stated that the emission specifications are unattainable without significant capital expenditure. MECA stated that NSCR can achieve NO_x emission reductions of more than 90% from rich-burn engines or engines operated stoichiometrically at a cost of $10 - $15 per brake horsepower (bhp), that SCR can achieve NO_x emission reductions of more than 90% from lean-burn engines at a cost of $50 - $125 per bhp, and that lean NO_x catalysts can achieve NO_x emission reductions of more than 80% from lean-burn engines at a cost of $10 - $20 per bhp. Enron, GPA, Kinder Morgan, Texas Eastern, TGC, and TGP suggested that the emission specifications be set by engine type (i.e., lean-burn or rich-burn), rather than the total horsepower at a site, to account for the more difficult-to-control higher levels of oxygen in the exhaust of a lean-burn engine. TCC, TxOGA, and Union Carbide suggested that the emission specifications be set for individual engines based on engine type or horsepower, rather than the total horsepower at a site. TGP suggested basing the emission specifications on the individual engine emission rate during the baseline periods (1997 - 1999), horsepower, rather than the total horsepower at a site or even a unit horsepower threshold. TGP also stated that the proposed 3,000 hp cut-off would require that some engines with low historic use and cleaner engines be converted to electric, while smaller base-load engines and older (more polluting) engines located at sites less than 3,000 hp would only have to apply low-NO_x controls but not convert to electric drive. Alternatively, TGP suggested requiring engines that emitted greater than 1.0 tpd in 1997 to be converted to electric (via a 0.17 g/hp-hr limit), with allowances for rich burn engines based on a 95% control from a 1997 baseline rate and allowances for lean-burn engines based on an 88% control from a 1997 baseline rate. For engines that emitted less than 1.0 tpd in 1997, TGP suggested NO_x

emission limits of 0.96 g/hp-hr for rich-burn engines and 1.31 g/hp-hr for lean-burn engines, with an exemption for emergency diesel and gas engines. TGP stated that its suggested "tiered control level" would result in a NO_x reduction of 78.02 tpd, as compared to the 78.50 tpd that the commission estimated in the rule proposal preamble. GPA suggested NO_x emission limits of 0.17 g/hp-hr for gas-fired rich-burn engines, and 2.0 to 5.0 g/hp-hr for gas-fired lean-burn engines. TGC suggested NO_x emission limits of 0.17 g/hp-hr for gas-fired rich-burn engines, and 0.50 g/hp-hr for gas-fired lean-burn engines. Texas Eastern suggested NO_x emission limits of 0.17 g/hp-hr for gas-fired rich-burn engines, and 0.51 g/hp-hr for gas-fired lean-burn engines.

The commission re-examined the proposed ESADs for gas-fired stationary IC engines in response to public comment. The basis of the proposed limit for sites with 3,000 hp of gas-fired engines was a strategy of replacement of these engines with electric motors. The proposed ESAD of 0.17 g/hp-hr was developed as an approximate equivalent to the NO_x emissions that would result from EGFs supplying the electricity to operate electric motors at the compressor sites. This emission proposal was not consistent with the other point source emission proposals in the sense that all the others were based on meeting the ESADs through the application of add-on technology. The majority of the engines at sites with 3,000 hp of gas-fired engines are lean-burn engines. It is not technically feasible currently for the large majority of the lean-burn engines to meet a 0.17 g NO_x/hp-hr limit through the application of add-on technology.

In response to the issues raised by the commenters, the commission has adjusted the IC engine ESAD to ensure that the ESADs are technically feasible without wholesale replacement of engines.

The adopted ESADs for IC engines are 0.17 g NO_x/hp-hr for gas-fired rich-burn engines, and 0.50 g NO_x/hp-hr for gas-fired lean-burn engines. The adopted ESADs accomplish almost the same level of reduction as the proposed ESADs, while moving the standard to one that is technically feasible based on application of emission controls. The adopted ESADs for IC engines will accomplish all but 1.8 tpd of the 78.5 tpd of NO_x reductions estimated in the rule proposal preamble.

These changes have the potential to reduce required capital expenditures significantly on a number of the engines. Approximately 50 of the lean-burn engines operate below 5.0 g NO_x/hp-hr, and these engines can be retrofitted with flue gas cleanup controls to meet the adopted ESAD of 0.50 g/hp-hr instead of being forced to convert to electric motors or obtain allowances. In the cost note of the proposal preamble, the commission estimated the cost of electrification at approximately $800 per hp, including cost of electric transmission lines. The preamble used the equation ($310,000 plus ($72.7 times hp)) to estimate SCR capital cost. Applying this equation to 42 of the engines with reported emissions below 5.0 g NO_x/hp-hr yields an average cost of $462/hp. However, for engines with higher emission baselines, the capital costs of electrification and Tier III controls are similar, so the adopted ESADs are still expected to result in the replacement of IC engines with electric drive motors, as in fact has already occurred at some sites due to such factors as the cost savings associated with increased automation and reduced labor costs for engine maintenance. Many of the gas-fired engines are more than 40 years old and replacing them will also offer the opportunity to make other upgrades at the plants, such as in metering and control. The conversion of gas-fired engines to electric motors will remove the

highest stationary source NO_x emitters from the airshed. However, with the adopted ESADs and the compliance flexibility offered by the cap and trade compliance program, a variety of strategies are expected to be used to reduce emissions. Many of the IC engines are transportable and some of the lean-burn engines could be swapped for rich-burn engines controlled with NSCR. Conversion to electric motors may be favored at sites with access to existing power lines of the appropriate size. The EPA's NO_x SIP call rules applicable in 22 eastern states of the United States include requirements for IC engines, which is currently stimulating development of new NO_x control technologies which may have applicability to the lean-burn gas engines in HGA.

BCCA stated that it reviewed worldwide retrofit experience for IC engines, and that it found no equipment designed for and meeting the proposed emission standards. BCCA asserted that the commission failed to take this worldwide lack of experience into account when setting the proposed emission limits.

The commission disagrees that there is no equipment designed for and meeting the adopted emission specifications. The adopted rich-burn engine ESAD of 0.17 g/hp-hr is achieved with NSCR technology. The EPA recently sponsored an update of the 1993 ACT for IC engines. This document, *Stationary Reciprocating IC Engines, Updated Information on NO_x Emissions and Control Techniques, Revised Final Report*, September 1, 2000, provides a review of NSCR performance testing in several California air quality districts. Test data from Santa Barbara County included 78 engines equipped with NSCR, representing 17 models in size from 48 hp to 747 hp. In 163 tests of these engines, the mean emission rate was 0.17 g/hp-hr. The adopted

ESAD for lean-burn IC engines is similar to the current VCAPCD rule, which is approximately equal to 0.62 g NO_x/hp-hr. Under the previous version of the VCAPCD rule, which required only an 80% reduction, several IC engine tests indicated lower levels than 0.5 g/hp-hr using SCR.

Pasadena/Donohue stated that it should be clarified that only gas-fired engines count toward the 3,000 hp cutoff.

The proposed and adopted ESADs are intended to apply only to gas-fired engines. In order to clarify this intent, the term "gas-fired" has been inserted in the IC engine ESADs of §117.206(c)(9). As discussed earlier in this preamble, the adopted ESADs are based on categorization as rich-burn or lean-burn rather than total site hp.

BCCA asserted that the preamble does not provide sufficient information to adequately analyze alternative approaches and stated that it was impossible to discern the relative number of rich-burn versus lean-burn affected engines or the average horsepower of either class, or the relative contribution of either class to the total tpd reduction.

BCCA member company ExxonMobil and several other companies requested and received from commission staff during the public comment period the emission inventory information used to develop the proposed IC engine ESADs. In their comments on the proposed rules, several of these companies included an analysis of the emission reductions that could be achieved by various suggested regulatory alternatives, including ones based on rich-burn or lean-burn characteristics.

Regarding reliability, Kinder Morgan, TGC, and TGP stated that they, like other interstate natural gas transmission companies, operate under a certificate issued by the Federal Energy Regulatory Commission (FERC), and that this certificate requires them to make available the necessary horsepower developed by the engines to compress and deliver natural gas to its customers throughout the country. GPA, TGC, and TGP stated that HGA forms a "hub" through which several interstate natural gas pipeline companies carry natural gas from the Gulf of Mexico to various parts of the country and stated that a compressor station that operates solely under electric power may not be able to transport natural gas to its customers in other parts of the country during periods of power failure or "brownouts." As examples of reliability concerns, GPA and TGP cited the acute power shortage during summer 2000 in Southern California and in past years in the northeast. TGP suggested that the rule allow at least 50% of natural gas compressors at a compressor station to remain gas-fired to ensure reliable transportation of natural gas during peak demand on the power grid.

Reliable transport of natural gas is important and the shift to electric motors in the transmission industry needs to be accompanied with contingency planning to ensure that power failures or brownouts do not seriously disrupt the ability to move gas. The cap and trade program makes it feasible to retain any number of existing gas-fired engines as standby units, operating only under emergency or maintenance conditions, with electric motors moving gas under all non-emergency conditions. Because electric motors generate no NO_x emissions, they would generate emission credits to cover NO_x emissions resulting from emergency or test operation of gas-fired engines. An additional compliance option made feasible by the adopted ESADs for gas-fired IC engines

would be to forego electric motors and comply by adding NO_x control technology to the existing gas-fired engines.

BCCA and Kinder Morgan commented on the ability of lean-burn gas-fired engines to meet a NO_x level of 0.50 g/hp-hr. BCCA and Kinder Morgan asserted that SCR retrofits have been tried on a small number of engines in gas compression service in California with negative results and that in all cases the operators who installed retrofit SCR abandoned its use, preferring instead to either accept a loss of capacity or find another way to achieve emission reductions. BCCA stated that EPA's ACT document, *Alternative Control Techniques Document - NO_x Emissions from Stationary Reciprocating Internal Combustion Engines*, Table 2.5, indicates that SCR can achieve 90% reduction on lean-burn engines. BCCA stated that only three of the six engines tested achieved 90% reduction on any test; only one engine (a small (291 hp), non-typical gas engine) reported greater than 90% reductions for all tests conducted; two other engines achieved 90% reduction on at least one test, but did not achieve that level on other tests; and two engines had at least one test that reported zero NO_x reduction. BCCA stated that test data with such variation over such a small sample is inadequate to support a decision to impose wide-scale retrofit of SCR technology on lean-burn engines. Kinder Morgan suggested that the commission reconsider the emissions specifications for lean-burn IC engines and establish emission limits based on existing, proven LEC technology.

Much of the SCR operating data in the 1993 ACT for gas compressor engines comes from a data base of test results for engines in Ventura County, California. This data was revisited in the September 1, 2000 EPA document, *Stationary Reciprocating IC Engines, Updated Information on*

***NO_x Emissions and Control Techniques, Revised Final Report*. The Ventura County data base includes 49 tests on seven engines with SCR, tested between 1986 - 1993. The engines were subject to the rule limits at the time, either a limit of 125 ppmv (approximately 1.7 g/hp-hr), or an 80% reduction. Rule compliance was indicated in all but two tests of one engine, an engine then taken out of service. Upstream concentration data, available on 42 of the compliance tests, shows an 84% average reduction. This data is clearly supportive of the ability of the technology to make the reductions necessary for compliance with the VCAPCD rule in effect. The fact that 90% reduction was only achieved on some of the tests is a function of the regulatory standards in place, rather than technical feasibility. SCR is a versatile technology and is capable of achieving reductions above 90%. In addition, as discussed in the response to the following comment, the Ventura County data from 1986 - 1993 represents the performance of first generation SCR on lean-burn IC engines, not current SCR capabilities. In 1993, Ventura County further tightened the NO_x emission limits to 45 ppm (approximately 0.62 g/hp-hr) or a 94% reduction, intentionally causing a shift from SCR-controlled engines to electric motors.**

BCCA, Goodyear, GPA, Kinder Morgan, Texas Eastern, TGC, and TGP stated that most engines in this class are used in either gas compression service or electrical power generation, both of which require that the engine follow swings in load, and that SCR is not very responsive to changing loads due to its inability to rapidly achieve a balance between inlet concentrations of NO_x and the ammonia injection. BCCA, Goodyear, and GPA stated that there have been no successful application of post-combustion control technology on load-following, lean-burn IC engines for a number of technical reasons, including difficulty in achieving and maintaining the required temperature window and

residence time for the NO_x reduction reactions to be effective. BCCA and GPA stated that some SCR vendors contend that the feedback problem has been solved by the application of modern PEMS which can react more rapidly than instruments, but that application of PEMS to date has been very limited and has been generally limited to new, well-instrumented, smaller, medium- to high-speed engines. BCCA stated that there is little evidence that it would be possible to retrofit adequate PEMS systems on the older, large bore, low speed engines in current use in HGA.

The first generation of SCR applied to engines did not address load following operation very well and as a result, SCR performance was not always acceptable. The new generation of SCR technology has demonstrated the ability to perform under engine load swings. In one example of SCR with feedforward controls on three 3,130 hp lean-burn engines operated in pipeline service at variable speed and load, during 20 individual test runs, the engines were found to be operating at between 0.11 g NO_x/hp-hr and 0.21 g NO_x/hp-hr. These emissions are well below the adopted 0.50 g NO_x/hp-hr ESAD for lean-burn gas engines. The nature of technological advance is that once a problem is solved, it no longer exists as a problem of whether it can be done, but as matter of application. The application of feedforward controls will be simpler on the better-instrumented engines, but the upgrade of lean-burn engines currently with older operating controls is technically feasible and could be performed in conjunction with Tier I low emission combustion modifications. Tier I retrofits will be needed for most of the older engines to bring emissions down to the range of 5.0 g NO_x/hp-hr, in order for SCR or other flue gas cleanup controls to further reduce emissions by 90% to 0.5 g NO_x/hp-hr. LEC retrofits are capable of achieving NO_x levels of two to three g/hp-hr on most engine models, adding flexibility to the combination of Tier

I and Tier II controls necessary to achieve the lean-burn engine ESAD.

As an alternative to SCR, NO_x adsorber catalyst technology is not as sensitive as SCR to variations in inlet NO_x concentration and appears to be promising in load-following gas-fired IC engine applications. The first commercial application of this technology to three 2,000 hp gas-fired lean-burn engines is underway at a semiconductor manufacturing facility in Dallas. The permit limit for these engines is 0.070 g/hp-hr, significantly lower than the adopted ESAD for lean-burn gas engines.

Goodyear stated that for gas-fired lean-burn engines rated at 700 hp or less, the proposed emission specification should be revised to limit NO_x emissions to no less than 4.0 g/hp-hr. Alternatively, Goodyear suggested that these engines be exempted. TGP suggested that the emission specifications be based upon NSR permitting BACT levels.

The commission disagrees with Goodyear's suggestions because if implemented they would result in minimal reductions from many stationary IC engines to which technically feasible controls can be applied to accomplish the necessary emission reductions. TGP's suggestion to base the emission specifications on NSR permitting is not a clear cut suggestion. Written guidance for IC engine BACT hasn't been updated in some time and does not reflect the capabilities of today's technology. For example, as discussed in the preceding response, the commission recently issued a construction permit for three 2,000 hp gas-fired engines with a NO_x emission limit of 0.070 g/hp-hr, using Tier III control technology. The new engines' combustion design is guaranteed to

achieve an emission rate of 0.7 g/hp-hr, which currently would not be a technically feasible Tier I level for low emission combustion retrofits.

TECHNICAL FEASIBILITY - PULPING LIQUOR RECOVERY FURNACES

BCCA, Sierra-Houston, Pasadena/Donohue, and TPIEC commented on the proposed NO_x emission specification of 0.050 lb/MMBtu for pulping liquor recovery furnaces in §117.206(c)(12). BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for pulping recovery furnaces. Sierra-Houston stated that the NO_x emission specification should be more stringent, while Pasadena/Donohue stated that §117.206(c)(12) should be deleted and §117.203 revised to specifically exempt pulping liquor recovery furnaces. TPIEC submitted a September 20, 2000 NCASI memo which stated that the requirement to use SNCR to achieve 64% NO_x reduction in a kraft recovery furnace is apparently based upon results from test runs conducted on the Swedish furnace in the early 1990s. The NCASI memo stated that the furnace on which the tests were conducted has since been decommissioned and a new furnace built at the same mill does not incorporate SNCR technology, and asserted that there is no published information on the use of SNCR on an existing and operating furnace anywhere in the world. Pasadena/Donohue similarly asserted that there has been no continuous demonstration of SNCR on a pulping recovery furnace and that a trial was conducted but the results were not conclusive, the trial furnace was shut down after the trial, and its replacement furnace was not equipped with SNCR. The NCASI memo stated that there are a number of unresolved critical issues surrounding the use of urea or ammonia injection in a recovery furnace for NO_x control, and that the design and function of a recovery furnace is first and foremost to operate as a chemical reactor to recover expensive cooking chemicals, with its role as a

steam-producing device secondary to this primary function. The NCASI memo stated that long-term tests need to be conducted on a furnace to ensure the injection of NO_x-reducing chemicals would not have any deleterious consequences on the kraft liquor chemical cycle. The NCASI memo also expressed concern about other unknown factors such as significant ammonia slip and corresponding impact on tube corrosion and fouling, potential for plume opacity problems due to ammonium chloride emissions, etc. NCASI stated that optimization of the staged combustion principle within an existing furnace to possibly obtain up to 30% reduction in prevailing NO_x emissions is perhaps the only technologically feasible alternative at the present time. Pasadena/Donohue stated that combustion controls which reduce combustion temperature could result in increased total reduced sulfur (TRS) and CO emissions, since increased temperature is used to control sulfur dioxide (SO_2) and TRS. Pasadena/Donohue stated that reduced furnace temperature could risk terminating the oxidation of the black liquor solids, resulting in "a significant explosion threat to the mill." Pasadena/Donohue stated that use of ammonia associated with SNCR in a sulfur-rich environment will result in the formation of ammonium sulfates and cause particulate and opacity problems. Pasadena/Donohue also stated that introduction of nitrogen (in the form of urea or ammonia) into the furnace will increase the concentration of nitrogen in the chemical recovery cycle (i.e., the black liquor, smelt, lime mud, and white liquor) since it is a closed system, such that any nitrogen captured in the electrostatic precipitator (ESP) or with the smelt will be released in the smelt tank, the lime kiln, or the recovery boiler, thereby possibly increasing NO_x emissions.

The commission disagrees with the commenters. There appears to be a basic misunderstanding of the chemistry of SNCR that is put forward as the primary theoretical roadblock to its use in

pulping liquor recovery furnaces. The issue of ammonia being somehow trapped in the "closed cycle" of the process, and concentrated to an undesirable level, coupled with high level of sulfur compounds, is not relevant in a mill using alkaline (black liquor) pulping. With large amounts of alkaline sodium and sodium oxide present, ammonia will not form ammonium sulfate salts. Instead, the sodium, being a much stronger reactant, will form sodium sulfate salts, causing the ammonia to remain in the gas phase and leave the system, rather than deposit in the ESP as the commenter asserted. Also, the commenters lack understanding of the complexity of the urea, ammonia, and NO_x reactions, as well as the amount of ammonia produced for every pound of urea fed. There are many other reaction paths that occur, including the conversion of urea to diatomic nitrogen and water, with a relatively small percentage leaving as ammonia slip. Urea reagent use actually tends to simplify the control of excess ammonia produced. Control of the excess ammonia generation is a part of the art and the science, as well as the economics, of the SNCR process, and a competently designed and operated system will minimize it. Indeed, an SNCR vendor typically guarantee five to ten ppm ammonia slip. The commission believes that issues related to ammonia release or concentration have been overcome through commercial development and experience in the last ten years.

As noted in the rule proposal preamble, the emission specification was based on the application of SNCR, which has previously been demonstrated to be technically feasible on a pulping liquor recovery furnace in 1991. That a subsequent replacement furnace was not equipped with SNCR may merely reflect the company's business decision not to spend the money to equip the new furnace with SNCR in the absence of regulations or BACT permitting requirements mandating

NO_x reductions that would motivate the company to install NO_x post-combustion control technologies. The commission has retained the ESAD for pulping liquor recovery furnaces as proposed, but has added an alternative ESAD of 1.08 lb NO_x per ADTP. Both pulping liquor recovery furnace ESADs provide for a NO_x reduction of 64%.

Pasadena/Donohue expressed compliance demonstration concerns, stating that measuring the furnace activity level is not easy and that there is no fuel source to meter since the furnace is normally heated via combustion of the organic matter in the black liquor solids. Pasadena/Donohue also stated that the organic content (and therefore the heating value) of the black liquor solids is highly variable, thus disallowing use of feed rate monitoring.

The commission agrees that pulping liquor recovery furnaces should be excluded from the fuel flow meter requirements for the reasons cited by the commenter. The commission has revised §117.213(a)(1)(B) accordingly. The commission has also revised §117.213(a)(1)(B) to exclude wood-fired boilers from the fuel flow meter requirements since it is impractical to install a monitor for fuel flow of a solid fuel.

TECHNICAL FEASIBILITY - LIME KILNS

BCCA, Sierra-Houston, Pasadena/Donohue, and TPIEC commented on the proposed emission specification for lime kilns in §117.206(c)(13)(A). BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for lime kilns, while Sierra-Houston stated that the proposed emission specification for lime kilns should be more

stringent. Pasadena/Donohue stated that §117.206(c)(13)(A) should be deleted and §117.203 revised to specifically exempt lime kilns. Pasadena/Donohue stated that staged combustion and mid-kiln firing have not been demonstrated on lime kilns and therefore are not technically feasible. Pasadena/Donohue stated that low-NO_x burners are not technically feasible on lime kilns due to "complexities resulting in poor efficiency, increased energy use, and decreased calcining. In addition, there is limited ability to reduce temperature in the kiln and stay within regulated limits for TRS emissions and maintain calcining capacity." TPIEC submitted a September 20, 2000 NCASI memo which stated that the requirement to use combustion controls such as low-NO_x burners, mid-kiln firing, and staged combustion to effect a NO_x removal capacity of about 39% is perhaps based upon their application to cement kilns rather than kraft pulp mill lime kilns. The NCASI memo stated that based upon an average lime kiln NO_x emission factor of 2.19 lb/ton CaO, a 70% reduction would be needed to get to an emission of 0.66 lb/ton CaO (and not 39%). The NCASI memo further stated that kraft lime kilns generally have limited operating flexibility relative to combustion NO_x controls in order to achieve the primary goal of kiln operation: a desired reburned lime purity and production rate. The NCASI memo stated that in order to keep the TRS emissions below what is typically an extremely tight limit (e.g., ten ppm TRS at 10% O_2), efforts to ensure TRS control take precedence over all other emission control strategies, and that low-NO_x burners on lime kilns are undesirable for these reasons. The NCASI memo further stated that mid-kiln firing is believed infeasible in the case of kraft lime kilns, although it may be a technology that is applicable to cement kilns. The NCASI memo stated that staged combustion may have only limited applicability due to the potentially undesirable impact on calcining capacity and kiln energy efficiency, as well as other potentially undesirable impacts on emissions of TRS and hazardous air pollutant (HAP) compounds.

The commission disagrees with Pasadena/Donohue's assertion that staged combustion and mid-kiln firing have not been demonstrated on lime kilns and therefore are not technically feasible. As noted earlier in this preamble, the installation of a control technology at a single source can sufficiently demonstrate its technical feasibility, and installation of a control technology at a source in one source category often can be "transferred" to other source categories. Also, the NCASI memo did not explain the basis for its assertion that "mid-kiln firing is believed infeasible in the case of kraft lime kilns." Nevertheless, in the case of lime kilns, at least two technologies can be transferred from the cement industry. One is reburn technology, in which reburn air is injected mid-kiln for rapid and complete cross-sectional mixing of the injected air with the gases in the kiln. The air is injected downstream of a substoichiometric zone in a gas temperature range sufficient to complete the combustion of residual CO and hydrocarbons. NO_x reduction is achieved by completely depleting the oxygen in the primary combustion zone, and providing the finishing oxygen in the proper temperature zone to complete combustion and minimize further NO_x formation.

In addition, low-NO_x natural gas burners are available that incorporate controlled flame turbulence, delayed fuel air mixing, establish a fuel rich zone, and achieve rapid ignition. Most gas burners incorporate the first three principles; however, because they use no primary air, ignition is delayed. Consequently, they do not take advantage of combustion in fuel rich zones, and the flames only burn on the surface where air has been able to mix. Low-NO_x gas burners use some primary air or a means of getting enough oxygen to the core of the flame to establish ignition. Low-NO_x burners have been installed in European lime kilns.

The NCASI memo recognized that NO_x emissions are a function of hot end temperature for gas-fired kilns. Since there is an incentive to operate at the lowest temperature that product can be made in order to minimize fuel costs, knowing the instantaneous NO_x level through the use of a NO_x monitor could be used in process control such that corrective action is taken to adjust the process when the NO_x level indicates a more-than-adequate temperature in the kiln. Reductions in the NO_x mass emission rate would come about through reduced fuel use and the associated reduced NO_x concentration. Tight process control using CO and O_2 monitoring in addition to NO_x should result in reduced NO_x emissions. Use of a NO_x monitor will also enable accurate characterization of NO_x behavior leading to additional NO_x reduction strategies.

As noted earlier, low-NO_x burners have been installed in European lime kilns. The commission acknowledges that it is not aware of specific situations in which combustion controls were used on lime kilns in the United States. However, it is also true that there have been no lime kiln regulations requiring NO_x reductions that would motivate potential users to install NO_x combustion control technologies. As NESCAUM (www.nescaum.org) noted in *Environmental Regulation and Technology Innovation: Controlling Mercury Emissions from Coal-Fired Boilers* (Publication SS-25, September 2000), implementation of technology historically follows regulation, and not the reverse. Once clear, enforceable standards are set, the regulated community and technology vendors have proven adept at finding cost-effective solutions and then implementing them.

TECHNICAL FEASIBILITY - LIGHTWEIGHT AGGREGATE KILNS

BCCA, Sierra-Houston, and TXI commented on the proposed emission specification of 0.76 lb NO_x per ton of product for lightweight aggregate kilns in §117.206(c)(13)(B). BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for lightweight aggregate kilns, while Sierra-Houston stated that the proposed emission specification should be more stringent. TXI stated that its lightweight aggregate kilns are fired on coal and natural gas, and must utilize approximately 100% excess air to properly operate and produce the desired product. TXI stated that it did not believe that the commission adequately investigated the technical feasibility of installing combustion controls on lightweight aggregate kilns. TXI stated that it is not aware of any technical information which indicates that SCR or SNCR has even been considered for use on lightweight aggregate kilns. TXI stated that other NO_x reduction techniques provide other difficulties in their application to lightweight aggregate kilns.

The commission agrees that high excess air is necessary in lightweight aggregate kilns to obtain the necessary thermal profile to expand the shale. The commission has investigated the technical feasibility of installing combustion controls on lightweight aggregate kilns. Specifically, FGR, reburn technology, and steam or water injection are available combustion controls technologies which will reduce NO_x emissions on lightweight aggregate kilns while maintaining the temperature profile necessary for producing the desired product. In FGR, low oxygen flue gas is substituted for the excess air. This flue gas replaces the thermal mass of excess air in the main flame, thereby maintaining the required thermal profile. At the same time, the flame burns in a reduced oxygen atmosphere initially and burns out at near stoichiometric conditions. The reduced availability of

oxygen throughout the entire combustion process results in reduced NO_x formation.

Further NO_x reductions can be achieved by combining FGR with reburn technology, in which reburn air is injected mid-kiln for rapid and complete cross-sectional mixing of the injected air with the gases in the kiln. The air is injected downstream of a substoichiometric zone in a gas temperature range sufficient to complete the combustion of residual CO and hydrocarbons. NO_x reduction is achieved by completely depleting the oxygen in the primary combustion zone, and providing the finishing oxygen in the proper temperature zone to complete combustion and minimize further NO_x formation.

A second method of adding thermal ballast to the flame of a lightweight aggregate kiln is by substituting steam or water for excess air. By adding water vapor to the combustion air, the thermal properties of high excess air can be achieved and the oxygen input can be kept near stoichiometric. Using water instead of air also enables the application of the previously described reburn technology where the main flame is operated slightly substoichiometric, and the overhead air is added downstream. Other available combustion controls are low-NO_x burner retrofits, and midkiln firing of coal or dewired tire chips. Both low-NO_x burners and midkiln firing are documented as successfully reducing NO_x emissions on cement kilns by over 30%, and it is reasonable to expect that similar emission reductions could be achieved on lightweight aggregate kilns. The adopted ESAD of 0.76 lb NO_x per ton of aggregate produced was calculated as a 30% reduction from the baseline emissions for these kilns, so the adopted ESAD is technically feasible.

In addition, since there is an incentive to operate at the lowest temperature that product can be made in order to minimize fuel costs, knowing the instantaneous NO_x level through the use of a NO_x monitor could be used in process control such that corrective action is taken to adjust the process when the NO_x level indicates a more-than-adequate temperature in the kiln. Reductions in the NO_x mass emission rate would come about through reduced fuel use and the associated reduced NO_x concentration. Tight process control using CO and O_2 monitoring in addition to NO_x should result in reduced NO_x emissions. Use of a NO_x monitor will also enable accurate characterization of NO_x behavior leading to additional NO_x reduction strategies.

Regarding post-combustion controls, the commission acknowledges that it is not aware of specific situations in which SCR or SNCR were considered for use on lightweight aggregate kilns. However, it is also true that there have been no lightweight aggregate kiln regulations requiring NO_x reductions that would motivate potential users to install these technologies. As noted earlier in this preamble, implementation of technology historically follows regulation, and not the reverse. Once clear, enforceable standards are set, the regulated community and technology vendors have proven adept at finding cost-effective solutions and then implementing them.

TXI suggested that NO_x emissions from lightweight aggregate kilns be addressed through the NSR permitting process, and noted that its kilns were already operating under NSR permits.

The commission disagrees with the commenter's suggestion because if implemented, the result would be no emission reductions from lightweight aggregate kilns to which technically feasible

controls can be applied to accomplish the necessary emission reductions, and would increase the NO_x cap established under the mass emissions cap and trade program.

TXI stated that the wording of the rule proposal preamble suggests that the only basis for the proposed emission specification is a 30% reduction from a 1997 baseline of 1.088 lb NO_x per ton of product. TXI stated that its emission rate has ranged from 1.088 lb NO_x per ton of product to 1.39 lb NO_x per ton of product, and that the proposed emission specification utilized the low end of this range by using 1997 as the baseline year. TXI commented that a reduction of 55% would be needed for continuous compliance.

The commission disagrees with the commenter. As noted earlier in this preamble, the commission staff used the 1997 emissions inventory as the basis for considering various combinations of ESADs for various categories of equipment to achieve a 90% reduction in point source NO_x emissions. Use of the 1997 emissions inventory is consistent with the method of analysis for all other equipment categories. In addition, use of the 1997 emissions inventory is consistent with the photochemical modeling analyses of NO_x point source emissions in support of the HGA ozone attainment demonstration, which are based on 1997 emissions. Therefore, use of the 1997 baseline was not arbitrary, as the commenter has implied, but in fact a necessary and consistent component of an approvable SIP revision. The commission also notes that the ESADs are used to establish allocations (NO_x emissions in tons) for the mass emissions cap and trade program. The commenter's concern that a greater reduction than actually represented by the lightweight aggregate kiln ESAD is needed for "continuous compliance" is unwarranted since the allowances

are allocated on a calendar year basis.

SCR removal efficiency of 80% would be a more representative design goal for dirty exhaust streams. The oxidation technologies appears capable of a 90% NO_x reduction. However, developing technologies, like NO_x oxidation, are likely to have more unforeseen practical challenges compared to established technologies that can compromise performance goals. Therefore, the commission has adopted the ESAD for lightweight aggregate kilns as proposed.

TECHNICAL FEASIBILITY - HEAT TREAT AND REHEAT FURNACES

BCCA, Sierra-Houston, and Wyman-Gordon commented on the proposed emission specifications for heat treat furnaces and reheat furnaces in §117.206(c)(14). Wyman-Gordon stated that the rule proposal preamble incorrectly identified its steel processing plant as having seven reheat furnaces and two heat treating furnaces subject to the proposed rule, noting that these furnaces are actually five reheat furnaces and four heat treating furnaces. Wyman-Gordon stated that correct classification is important because the emission specifications and costs are different for the two types of furnaces.

The commission agrees that correct classification of the furnaces is important, and notes that the commission's classification of the commenter's furnaces in the rule proposal preamble was based on information that the company submitted in its 1997 emissions inventory. The commission has corrected the classification of Wyman-Gordon's reheat furnaces and heat treating furnaces in the table in the Tables and Graphics section of this issue of the *Texas Register*, titled "Subcategories - Point Source Potential NO_x Emission Reductions for Houston/Galveston Nonattainment Area

Counties."

BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for heat treat and reheat furnaces. Wyman-Gordon commented that the EPA's *Alternative Control Techniques Document - NO_x Emissions From Iron and Steel Mills* states on page 5-8 that heat treat furnaces "operate at a very specific flame point and furnace geometries to achieve a specific 'set point' past which steel processing is most efficient; major problems may occur for a specific furnace without a large amount of equipment reconstruction." Wyman-Gordon stated that its furnaces have custom designed and built proprietary burners which already have very low NO_x emission rates as compared to standard burners commonly used in reheat and heat treat furnaces. Wyman-Gordon stated that because the burners are custom built, it is not possible to retrofit the burners with an "off the shelf" low-NO_x package and that instead, each burner would need to be completely rebuilt or replaced to achieve the proposed emission rates. Wyman-Gordon also stated that the new burners would have different flame characteristics than the existing burners, requiring modeling and an engineering study to determine the correct placement to achieve uniform heating in the furnaces. Wyman-Gordon stated that the commission assumed an unreasonably low NO_x emission rate from uncontrolled furnaces, and that the EPA and State and Territorial Air Pollution Program Administrators (STAPPA)/Association of Local Air Pollution Control Officials (ALAPCO) developed higher emission rates for controlled and uncontrolled heat treat and reheat furnaces. Wyman-Gordon stated that the proposal should be revised to reflect more realistic uncontrolled emission rates and to reflect the fact that most furnaces use pre-heated air, and that otherwise it would have to reduce its preheated air reheat furnace emissions by 70% and its heat treat furnace emissions by 93%. Wyman-Gordon stated that

these reductions are greater than those specified in the proposal and may not be achievable, or may require installation of both low-NO_x burners and SCR at a "dramatically" increased cost of control.

The commission agrees that accurate information is important and notes that the emission rates for the commenter's furnaces were supplied by the commenter as part of the commission's rate data survey of the 1997 emissions inventory. The commission also notes that Tier I control options other than low-NO_x burners are available to reduce emissions from heat treat furnaces and reheat furnaces. 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 Texas, this is currently achieving 0.04 lb/MMBtu, with expectations of even better performance. Other control options are also available. 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 a combination of the two approaches.

Sierra-Houston stated that the emission specification for heat treat furnaces and reheat furnaces in §117.206(c)(14) should be more stringent. Wyman-Gordon stated that its 1997 emissions inventory reflects calculation of potential emissions rather than actual emissions, thus overestimating natural gas usage and, in turn, daily and annual emission rates. Wyman-Gordon suggested that the uncontrolled

emission rate for its heat treat furnaces and reheat furnaces be set at 0.20 lb/MMBtu, and the emission specification for heat treat furnaces and reheat furnaces set at 0.13 and 0.10 lb/MMBtu, respectively.

The commission disagrees with Wyman-Gordon's suggested ESADs because they would result in no emission reductions from heat treat furnaces and reheat furnaces to which technically feasible controls can be applied to accomplish the necessary emission reductions. In addition, the suggested ESADs would increase the NO_x cap established under the mass emissions cap and trade program. The commission evaluated a variety of possible ESADs and has adopted the ESADs for heat treat furnaces and reheat furnaces as proposed.

TECHNICAL FEASIBILITY - DRYERS

BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for dryers.

As the commission stated in the rule proposal preamble, "(t)he proposed emission limit for magnesium chloride fluidized bed dryers is a 90% reduction from 1997 ozone season daily NO_x emissions. The proposed 41% NO_x emission reduction from the dryer category would be expected to necessitate SCR on the one affected dryer; however, this dryer is currently shut down. According to the company, there are no plans to reactivate this dryer. Consequently, the total annual fiscal impact for dryers in HGA is assumed to be zero." (See the August 25, 2000 issue of the *Texas Register* (25 TexReg 8290).) Because the one affected dryer has been permanently shut down, there is no need for a detailed technical discussion of the technical feasibility of the ESAD

for dryers. However, SCR is a well-established Tier II flue gas NO_x control technology. The technical issues of SCR on dryers are expected to be similar to those for other NO_x source categories.

Sierra-Houston stated that the emission specification for dryers in §117.206(c)(15) should be more stringent.

The commission disagrees with the commenter. The emission specification will require a 90% reduction from the emission factor used to calculate the 1997 ozone season daily NO_x emissions, and will affect a single dryer which had reported NO_x emissions of 1.05 tpd (383.87 tpy) in 1997. No other dryer in HGA had NO_x emissions greater than 0.07 tpd. The commission believes that the emission specification is appropriate, but has replaced the phrase "1997 ozone season" with "June - August 1997" since ozone season is not defined. It should be noted that the commission identified approximately 45 dryers with 1997 emissions of 0.01 to 0.07 tpd. In the future, the commission may pursue emission reductions from these currently-exempt dryers in HGA if additional reductions are determined to be necessary to reach attainment with the ozone NAAQS.

TECHNICAL FEASIBILITY - INCINERATORS

BASF, Sierra-Houston, Pasadena/Donohue, Safety-Kleen, and TPIEC commented on the proposed NO_x emission specification for incinerators in §117.206(c)(16), 10% of the 1997 rates (i.e., a 90% reduction from the 1997 rates). BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for incinerators. Sierra-Houston stated that the

emission specification for incinerators should be more stringent. Safety-Kleen stated that incinerators are designed to destroy organic contaminants in waste streams that cannot be disposed by other methodologies. Safety-Kleen stated that many of those streams contain irreducible levels of compounds that contribute to the generation of NO_x when the waste is incinerated. Safety-Kleen stated that waste streams are typically the by-products of production processes, and therefore, control on the quality of waste streams rests entirely in the hands of the generators. Safety-Kleen stated that many waste streams contain chemical-bound nitrogen and that the market for these wastes is growing. Safety-Kleen stated that it has systems in place to predict Btu-loading, ash-loading, metals emission, and the formation of by-products which could damage the refractory lining of the units, but that due to the waste's variability and the uncertainty of the possible mechanisms for NO_x formation during the simultaneous incineration of multiple waste streams, it is extremely difficult to predict NO_x formation. Safety-Kleen stated that SNCR is "the most stringent NO_x-reduction technology available" and has been shown to reduce NO_x emissions by up to 80 - 90%, but that SNCR will, by itself, be inadequate to control meet the proposed emission specifications. Safety-Kleen also stated that SNCR designs are predicated on singular waste streams with no variability, and that a 90% reduction in NO_x emissions has never been demonstrated in the hazardous waste industry.

The commission considered the waste streams in the HGA incinerators in response to these comments and agrees with the commenters that certain of the units have “dirty” exhaust streams, primarily with sulfur and chlorides, and a few with some metals and other inorganics. 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. SNCR will not be adversely affected by these inorganics, 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.

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 first 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 incinerators with higher levels of inorganics will pose greater technical challenges than cleaner, hydrocarbon-only streams. SCR removal efficiency of 80% is a more reasonable design goal for dirty fuel streams. The

incinerators 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 incinerator 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 commission has modified the ESAD for incinerators. The adopted ESAD for these units is either an 80% reduction from baseline, or 0.030 lb/MMBtu.

Safety-Kleen stated that because it is the only commercial hazardous waste incineration facility in HGA and the largest incinerator in HGA, the proposed rule "poses an unfair and extreme burden on this facility, the result of which will have a significant, adverse impact on the competitiveness of the facility in a small, highly-competitive marketplace." Safety-Kleen stated that by comparison, the other incineration facilities in the area only process smaller amounts of waste streams generated on-site, affording them a great deal more process control regarding NO_x formation. Safety-Kleen also expressed concern about potential increased "risk of harm to human health, safety, and the environment" associated with the transportation of hazardous waste to its distant competitors.

The commission does not believe that the rule will pose an unfair burden on Safety-Kleen. Safety-Kleen may be the only commercial hazardous waste incineration facility in HGA, but it is not the largest incinerator in HGA based on emissions or mass emission rate. The types of emission

control that Safety-Kleen is likely to employ to reduce NO_x emissions will be post-combustion controls similar to other facilities in the area, referenced in the preceding responses to comments. Concerning potential increased "risk of harm to human health, safety, and the environment" associated with the transportation of hazardous waste to Safety-Kleen's distant competitors, the commission is addressing issues of cost and technical feasibility of compliance with the ESADs, rather than transportation issues. Consideration of any possible risks associated with transportation of hazardous wastes is beyond the scope of this rulemaking. As previously stated, in consideration of Safety-Kleen's and others' comments on the technical difficulties of reducing NO_x from dirty streams, the commission adopted a less stringent emission standard for incinerators.

TPIEC submitted a September 20, 2000 NCASI memo which stated that Kraft pulp mills collect their low volume high concentration (LVHC) non-condensible gases (NCG) and burn them in lime kilns, boilers, or stand-alone thermal oxidizers. The NCASI memo stated that the LVHCs are rich in TRS compounds and organics such as terpenes and methanol, and that low levels of NO_x emissions are feasible from the burning of these kraft pulping and evaporator NCGs in thermal oxidizers. The NCASI memo further stated that higher levels (from 5 to 46 lb/hr) have been measured in oxidizers that also burn stripper off-gases (SOGs) containing significant levels of ammonia, and that due to the high levels of SO_2 resulting from oxidation of the TRS compounds, most thermal oxidizers are equipped with a wet scrubber for SO_2 removal.

The NCASI memo stated that reduction of NO_x emissions by maximizing the principles of staged

combustion, especially when ammonia-rich SOGs are burned, may be feasible, but that since the burning of SOGs in thermal oxidizers is in itself a fairly recent practice, efforts to bring this about are still in a fairly very exploratory stage and very well documented. The NCASI memo further stated that NO_x reduction by the use of SCR and SNCR technologies have also been reported in some Scandinavian mills, but their applicability to United States mill conditions remains uncertain. The NCASI memo stated that the requirement for a 90% NO_x reduction has no proven technological basis, and that due to the complexity of what causes NO_x to form in a thermal oxidizer, the floor representing uncontrolled NO_x emissions from thermal oxidizers has not yet been firmly established. The NCASI memo stated that the United States experience in bringing about high thermal oxidizer NO_x emissions reduction is limited, and that any requirement for NO_x emissions reduction from thermal oxidizers has to be determined on a case-by-case basis after satisfactory trials have been performed.

The commission adopted an alternate standard for incinerators based on an 80% reduction from 1997 levels, or 0.030 lb NO_x/MMBtu. The numerical emission standard will enable devices such as regenerative thermal oxidizers, which are inherently low-NO_x sources, to comply either without making reductions, or with small reductions.

BASF stated that the proposed emission specification penalizes incinerators that operated with a low NO_x emission rate in 1997. BASF also stated that the emission specification does not address incinerators that began operation or underwent a change in operation after 1997. BASF stated that NO_x emission increases may occur due to very high incinerator temperatures required to meet increasingly stringent VOC or HAP requirements for incinerators (MACT standards, BACT, etc.). BASF suggested

that the emission specification for incinerators beginning operation after 1997 be the currently permitted emission factor. TCC stated that the commission should set an attainable standard for incinerators rather than a percent reduction.

The commission adopted an alternate standard for incinerators based on an 80% reduction from 1997 levels, or 0.030 lb NO_x/MMBtu. The numerical emission standard will enable newer sources which have been designed through combustion modifications as inherently low-NO_x sources, to comply either without making reductions, or with small reductions.

BASF stated that the reference to "fume abaters" in §117.206(c)(16) should be deleted and that vapor combustors, thermal oxidizers, and enclosed flares should be considered to be flares that are exempt from §117.206. TCC and Union Carbide submitted similar comments. BASF, Phillips 66, and TCC stated that the term "fume abater" is not consistent with the definition of "incinerator" in §101.1 and the use of "incinerator" in 30 TAC Chapter 115.

As discussed later in the *DEFINITIONS* section of this preamble, the commission identified incinerators (including enclosed control devices that combust or oxidize gases or vapors (e.g., vapor combustors and thermal oxidizers)) with more than 40 MMBtu/hr design heat input and BIF units as the largest NO_x emission sources within the category of waste combustion devices. Although the term "incinerator" is defined in §101.1 to refer to units which burn wastes for the primary purpose of reducing volume and weight, this term historically has also been used to refer to enclosed control devices that combust or oxidize gases or vapors, particularly in Chapter 115.

The ESADs for incinerators apply to both types of units. Therefore, the commission has added a definition to §117.10 to clarify that for the purposes of Chapter 117, the term "incinerator" includes both enclosed control devices that combust or oxidize gases or vapors, and incinerators as defined in §101.1. The new definition is not a substantive change from how this term is intended to be used in Chapter 117, and its inclusion in the adopted rule will provide clarity. Subsequent definitions in §117.10 were renumbered due to the addition of the definition of "incinerator." Because "fume abaters" (meaning enclosed control devices that combust or oxidize gases or vapors (e.g., vapor combustors and thermal oxidizers)) are now clearly included in the new definition of "incinerator" in §117.10, the commission has replaced the reference to incinerators (including fume abaters)" with a reference to "incinerators" in §§117.201(12), 117.203(a)(4), and 117.206(c)(16).

Pasadena/Donohue stated that regenerative, recuperative, catalytic, and packed bed oxidizers are designed to operate at less than 2,000 degrees Fahrenheit and that thermal NO_x is not likely to be generated at this low temperature. Pasadena/Donohue also stated that these units typically burn natural gas only during start-up and to maintain the bed temperature. Pasadena/Donohue suggested that §117.203(a)(4)(A) be revised to exempt these units if they have a maximum design temperature greater than 2,000 degrees Fahrenheit.

The commission adopted an alternate standard for incinerators based on an 80% reduction from 1997 levels, or 0.030 lb NO_x/MMBtu. The numerical emission standard will enable devices such as regenerative thermal oxidizers, which are inherently low-NO_x sources, to comply either without

making reductions, or with small reductions.

AMMONIA AND CO EMISSIONS

BCCA, Entergy, Equistar, ExxonMobil, and Lyondell asserted that the proposed rules were developed with a less than complete analysis of the possible environmental disbenefit of the proposed controls. BCCA, Dynegy, Entergy, Equistar, Goodyear, GPA, Lyondell, Phillips 66, TCC, TPIEC, TxOGA, and Union Carbide expressed concern about increases in ammonia emissions associated with SCR and SNCR. BCCA stated that if all combustion units greater than 40 MMBtu/hr used ammonia-based NO_x control technologies at an ammonia slip rate of ten ppm, ammonia emissions in HGA would increase approximately 31.5 tons per day and bring some of the HGA counties to the top of EPA's Toxic Release Inventory list for ammonia. TCC stated that ammonia is considered a more toxic and severe pollutant than NO_x. An individual expressed concern about possible increases in CO, VOC, and ammonia associated with post-combustion controls. BCCA estimated that ammonia usage in HGA will increase by 330 tpd under the proposed point source control strategy. BCCA, Dynegy, Entergy, Equistar, Goodyear, GPA, Lyondell, Phillips 66, TCC, TPIEC, TxOGA, Union Carbide, and Valero expressed concerns about safety of transportation, storage, and handling of ammonia. The commenters stated that before mandating the widespread use of ammonia-based NO_x control technologies, the commission should assess the overall regional risk of introducing new quantities of ammonia in HGA relative to the NO_x/ozone reduction benefit derived from the controls. TCC also stated that the commission should revisit the benefits of applying SCR to smaller facilities given the known adverse impacts of ammonia.

The commenter's estimate of 31.5 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 rule cost note section of the rule proposal preamble. 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, the commenter's estimate of 31.5 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 5% (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 risks associated with anhydrous ammonia concern its asphyxiant and moderate combustibility properties. It is not classified as a hazardous air pollutant chemical and is lighter than air, so it

dissipates readily. It is routinely handled by farmers and used in many industrial applications throughout the country. However, its asphyxiant and combustibility properties cannot be taken lightly. Various safety programs such as the Accidental Chemical Release Risk Management Program will minimize risks associated with the transportation, storage, and handling of ammonia. Most of the safety concerns related to anhydrous ammonia can be avoided through the use of aqueous ammonia, which has concentrations of less than 30% ammonia in water, or urea, which is noncombustible. Urea can be shipped either as a solid or as a liquid solution in water. Processes are available which convert urea into ammonia on-site as needed, which avoids whatever risks may be associated with the transportation, storage, and handling of ammonia. Another approach, one that New Jersey follows, is to limit the quantity of anhydrous ammonia that may be stored, allowing a water solution with a maximum ammonia concentration of 26%, which reduces or eliminates concerns about accidental releases.

BCCA and TCC commented that if there is a significant quantity of unneutralized acids (e.g., sulfuric acid) in the atmosphere, then increases in ambient concentrations of ammonia will lead to increased particulate matter. BCCA stated that ambient particulate data collected across the Greater Houston area by the City of Houston, the TNRCC, and the Houston Regional Monitoring Corporation from March 1997 to March 1998 suggests that 10% - 30% of the acids contained in ambient particulates are not neutralized. BCCA stated that consequently, particulate matter in the region is acidic, such that increasing ammonia concentrations have the potential to increase fine particulate matter ambient concentration in the form of ammonium sulfate. BCCA stated that in HGA, full neutralization of the sulfuric acid could lead to an increase in ambient fine particulate matter of 0.2 to 0.5 micrograms per

cubic meter ($\mu g/m^3$). BCCA stated that it is also possible that the increased ammonia emissions might neutralize nitric acid, forming ammonium nitrate, which might add further to ambient particulate matter concentrations. BCCA commented that an increased mass of particulate matter in the atmosphere would drive the HGA closer to violating the pending NAAQS for fine particulate matter (i.e., particulate matter of less than 2.5 microns ($PM_{2.5}$)). BCCA stated that the commission should fully assess the benefits (e.g., lower ozone) and potential risk (e.g., higher particulates) of requiring NO_x control technologies that increase ammonia emissions. Fuel Tech commented that both NO_x and ammonia emissions contribute to fine particulate formation and stated that NO_x contributes to acid aerosol formation, while ammonia neutralizes atmospheric acidity. Fuel Tech commented that nitrogen is a biological fertilizer, irrespective of whether the nitrogen came from ammonia or NO_x emissions, and stated that the tradeoff between ammonia and NO_x emissions should favor the option that reduces the total amount of reduced and oxidized nitrogen. Sierra-Houston recommended that the allowable ammonia slip be five to seven ppmv, rather than ten ppmv, while Fuel Tech recommended that the allowable ammonia slip be 20 ppmv to reduce the required catalyst volume and associated capital cost. Fuel Tech stated that the additional ammonia emissions associated with higher (20 ppmv) ammonia slip is worth the additional NO_x reduction realized.

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.

TPIEC stated that no consideration appears to have been given to the potential impact of urea or ammonia slip with respect to deposition in local waterways as well as the Gulf of Mexico. TPIEC stated that unconverted ammonia/urea would be deposited in local areas and naturally converted to various nutrients, and that these nutrients could potentially impact the local watershed as well as the coastal ecosystem. TPIEC stated that the National Centers for Coastal Ocean Science's (NCCOS) *Gulf of Mexico Hypoxia Assessment* report indicates that nutrient loading issues are one of the major stresses to the coastal ecosystem in the Gulf of Mexico. TPIEC commented that an excerpt from the introduction of the report states: "Nutrient over-enrichment from anthropogenic sources is one of the major stresses impacting coastal ecosystems. Generally, excess nutrients lead to increased algal production and increased availability of organic carbon within an ecosystem, a process known as eutrophication. There are multiple sources of excessive nutrients in watersheds, both point and non-point, and the transport and delivery of these nutrients is a complex process, which is controlled by a range of factors. These include not only the chemistry, but also the ecology, hydrology, and geomorphology of the various portions of a watershed and that of the receiving system. Both the near-coastal hydrodynamics that generate water column stratification and the nutrients that fuel primary

productivity contribute to the formation of hypoxic zones. Human activities on land can add excess nutrients to coastal areas or compromise the ability of ecosystems to remove nutrients either from the landscape or from the waterways themselves." TPIEC stated that the creation of additional nutrients from excess ammonia slip could also add to the top fifteen impairments cited in the Clean Water Act 303(d) list which will be used in the development of the total maximum daily loading (TMDL) criteria. TPIEC stated that of the fifteen impairments listed, nutrient loading, reduced dissolved oxygen issues, suspended solids, as well as the growth of noxious plants (algae) could all be adversely impacted by the increased nutrient loading created by the ammonia/urea slip and consequent nutrient loading issues.

The commission agrees that airborne emissions from nearby as well as distant sources contribute pollutant loadings to waters through atmospheric deposition. Logically, reductions in the emission rates of NO_x and ammonia would result in reduced deposition rates of inorganic nitrogen (e.g., NO_x, ammonia) to local waterways as well as the Gulf of Mexico. Indeed, in the Executive Summary for the EPA's *Deposition of Air Pollutants to the Great Waters - Third Report to Congress* (June 2000), the EPA noted that "actions taken by EPA and others to control sources of Great Waters pollutants of concern appear to have positively affected trends in pollutant concentrations measured in air, water, sediment, and biota." The EPA further stated that "pollutant emissions will be further controlled by several rules scheduled to take effect in coming years. As a result, atmospheric deposition and loadings of these pollutants (NO_x, etc.) may be significantly reduced." The EPA also noted that actions taken to "implement pollution control laws issued by States and other nations will further reduce pollutant loadings to the Great Waters." The ESADs will result in an estimated 595 tpd reduction in NO_x emissions (equivalent to 181 tpd of pure nitrogen), while

generating perhaps 15 tpd of additional ammonia emissions (equivalent to 12.4 tpd of pure nitrogen). The resulting estimated 595 tpd reduction in NO_x emissions, coupled with the estimated 15 tpd increase in ammonia emissions, represents a significant reduction in inorganic nitrogen emissions (approximately 169 tpd of pure nitrogen) from NO_x point sources. This likewise represents a corresponding reduction in inorganic nitrogen deposition to local waterways and the Gulf of Mexico, thereby reducing the associated nitrogen nutrient loading.

Oceanographers have determined that nitrogen is the limiting nutrient in marine systems for algal growth (along with trace elements such as iron). The Gulf of Mexico hypoxia problem is linked to nitrogen loads to the Gulf along with periods of thermal stratification. In the Gulf Hypoxia study conducted by the National Oceanic and Atmospheric Administration (NOAA), (*NOAA Coastal Ocean Program Decision Analysis Series No. 17*, May 1999), the nitrogen budget to the Gulf of Mexico was estimated from all potential sources. Agricultural activities are the largest estimated nitrogen source with fertilizer and mineralized soil organic nitrogen contributing about 50%. Nitrogen sources such as groundwater discharge, soil erosion, and atmospheric deposition contribute about 24%. Animal manure contributes about 15%, and municipal and industrial sources add the remaining 11%. In contrast to results reported for Chesapeake Bay, atmospheric deposition of nitrogen appears to be a relatively small contributor to the total nitrogen load to the Gulf of Mexico. Atmospheric deposition of nitrate (wet and dry) in the upper Ohio River Basin watersheds (power plants) which is consequently washed into the river tributaries may be important to the overall delivery to the Gulf, and atmospheric deposition of ammonia from manure is higher in Iowa, Minnesota, and Illinois; however, the largest source is from commercial

fertilizers in the Mississippi River and Ohio River watersheds. Direct atmospheric deposition of nitrogen to the Gulf of Mexico is estimated at less than 1.0% of the total nitrogen loading.

There are many estuaries around the Gulf (all of which are nitrogen limited) such as Galveston Bay, Sabine Lake, Matagorda Bay, and Upper and Lower Laguna Madre, for which atmospheric deposition is a larger percentage of the nitrogen load, and the direct deposition to these shallow bays is more than 1.0% of the load. The Mississippi numbers are not representative of these other systems. Nonetheless, the nitrogen load from direct deposition is small compared to the nitrogen load coming into these bays from indirect deposition to the watershed, mediation by the terrestrial ecosystem and flow into the estuaries. The estimated 169 tpd reduction in pure nitrogen emissions resulting from implementation of the ESADs will reduce the atmospheric nitrogen deposition to these ecosystems, thus improving their water quality.

Calpine and RMT questioned whether the CO and ammonia limits of §117.206(e) apply to stationary gas turbines with duct burners in their exhaust ducts. Calpine and RMT expressed concern that the definition of "boiler" in §117.10(6) could be construed to include duct burners in stationary gas turbine exhaust ducts.

The CO and ammonia limits apply to any NO_x source which is subject to a NO_x emission specification under §117.106 or §117.206, including duct burners in gas turbine exhausts. The commission notes that the applicable emission specification for duct burners is 0.015 lb NO_x/MMBtu. The commission has clarified the adopted rule language of §117.106(d) by changing

"utility boiler" to "unit." This change will not impact any additional units in BPA and DFW because §117.106(a) and (b) only apply to utility boilers. The commission has likewise clarified the adopted rule language of §117.206(e) by changing "boiler or process heater" to "unit." This change will not impact any additional units in BPA because §117.206(a) only applies to boilers and process heaters in BPA. In DFW, §117.206(b) likewise already applies to boilers and process heaters, and therefore this change will not impact any boilers or process heaters in DFW. Although §117.206(b) also applies to gas-fired and gas/liquid-fired lean-burn stationary reciprocating IC engines in DFW, none of the three engines in DFW which are subject to §117.206(b) would have to comply with the ammonia limit because they can meet the emission limits using LEC modifications rather than post-combustion controls. Regarding the CO limits, the commission revised §117.206(e) to specifically exclude stationary IC engines in BPA and DFW because these engines are already subject to a CO limit in §117.205(e) and §117.206(b)(2), respectively. The commission revised §117.206(e)(1) by specifying a CO limit for IC engines in HGA that is consistent with these existing CO standards. The commission also revised §117.206(e) to specifically exclude BIF units and incinerators in HGA which are already subject to CO limits in other rules (for example, 40 CFR 266.102(e)(2)(ii)(A) and 40 CFR 266.104(b)). Finally, as discussed later in the *EXEMPTIONS* section of this preamble, the commission has excluded boilers and process heaters operating in "hot-standby" mode and lightweight aggregate kilns from correcting CO to 3.0% O_2, dry basis, because these units typically will operate with high excess O_2 which will drive the CO level, when corrected to 3.0% O_2, to a high level.

Calpine requested that §117.206(e) not be included as part of the SIP revision submitted to EPA

because CO and ammonia are not required to be regulated for demonstration of compliance with the ozone standard. Chevron suggested that the CO limits be deleted because HGA currently meets the NAAQS for CO.

The adopted emission limits of §117.106(d) and §117.206(e) address pollutants which may increase as an incidental result of compliance with the adopted NO_x limits. The adopted CO limit is consistent with the existing CO limit of §117.105(i) and §117.205(f) because nothing in these rules necessitates changing the existing limit. The adopted ammonia limit of ten ppmv is lower than the existing limit of §117.105(j) and §117.205(g). The adopted ammonia limit 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 NESCAUM's "*Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers*" (June 1998). It is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The commission is not including these related pollutant limits in the attainment demonstration SIP in order to simplify the approval process for alternative emission specification under §117.121 and §117.221 and eliminate the need for case-specific SIP revisions to complete the approval of an alternate CO or ammonia limit. Therefore, approvals of an alternate CO or ammonia limit under §117.121 or §117.221 can be done without EPA involvement (i.e., no case-specific SIP revision needed) since the commission is not including these approvals in the attainment demonstration SIP. The commission has clarified §117.121(a) and §117.221(a) by adding references to §117.106(d) and §117.206(e), respectively.

REI stated that the CO limitation specified in §117.105(h) and §117.106(d)(1) should be revised to include the appropriate CO emission rates for oil- and coal-fired units. REI stated that the currently specified 0.30 lb/MMBtu limitation correctly characterizes CO emissions of 400 ppmv corrected to 3.0% O_2 from gas-fired units, but that due to different conversion factors, the appropriate values for oil- and coal-fired units are 0.31 lb/MMBtu and 0.33 lb/MMBtu, respectively.

It is standard practice in the field of air pollution control to reference concentration limits to a flue gas oxygen concentration, to address the effects of dilution. The commission notes that the suggested equivalent alternate standard based on heat input would simplify compliance tracking for monitoring systems which are based on carbon dioxide as the diluent. Therefore, the commission has revised §117.105(h) and §117.106(d)(1) accordingly.

PERMITTING

GEHC, HDHHS, Mothers for Clean Air, and 61 individuals stated that facilities that predate the commission's air permitting requirements (i.e., those that are "grandfathered") should be subject to the NO_x emission specifications. GHASP commented that all grandfathered facilities should be investigated to be certain that they are properly so designated since many of these facilities have made modifications. State Senator Carlos Truan commented that a problem with the proposed rules is that they do not deal with grandfathered facilities and that the commission has let these facilities avoid permitting through the use of standard exemptions.

The commission has made no change in response to the comments. The adopted rules that apply to

facilities, for example the Chapter 117 NO_x requirements and the Chapter 115 VOC requirements, apply to both permitted and non-permitted ("grandfathered") sources in HGA. The commission agrees that it is appropriate to pursue cost-effective measures to reduce pollution; however, any such measures must be within the statutory authority of the commission. The TCAA does not authorize the commission to require grandfathered sources to obtain permits in order to operate, or to prohibit operation of those sources. A grandfathered facility is one that existed at the time the Texas Legislature amended the TCAA in 1971. These facilities were not required to comply with (i.e., were grandfathered from) the then-new requirement to obtain permits for construction activities. Whenever a grandfathered facility is modified (as that term is defined in the TCAA), it is required to comply with the TCAA permitting requirements in order to be authorized to construct and operate that modification. If a grandfathered facility has never been modified, it continues to be authorized by the TCAA to operate without a permit. Further, the definition of "modification" specifically excludes changes to facilities that are authorized by an exemption; i.e., any facility, including a grandfathered facility, can make a change using a commission exemption (now permit by rule) and this change is not considered to be a modification that would trigger the permitting requirements of the TCAA. During the 76th Texas Legislative Session in 1999, the issue of grandfathered sources was addressed by two different legislative programs. SB 766 was passed, which provided a framework for a voluntary permitting program for grandfathered sources under the TCAA, as well as SB 7, which requires mandatory permitting and emission reductions from EGFs. The commission continues to pursue enforcement action against companies who are not in compliance with the permitting requirements of the TCAA. However, SB 766 does provide for amnesty from enforcement for facilities eligible to

participate in the voluntary emission reduction permit program as long as a permit application is received before the TCAA deadline of September 1, 2001.

An individual stated that the commission should publish the names of grandfathered sources and how much each emits.

The commission has already published the names of grandfathered sources and how much each emits. This information is available on the commission's website at: http://www.tnrcc.state.tx.us/air/care/eidata.html. Additional information concerning grandfathered sources and their emissions is available on the commission's website at: http://www.tnrcc.state.tx.us/grandfathered/index.html.

GEHC and eight individuals suggested a moratorium on issuance of NSR permits and/or plant expansions.

The mass emissions cap and trade program will cap the level of NO_x emitted from stationary sources in the HGA area, 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 their 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. For reaching attainment with the ozone standard, controlling emissions is necessary, as opposed to limiting NSR permit issuance and/or plant expansions. Therefore, the commission disagrees with the commenters' suggestion and has made

no change in response to the comment.

The EPA commented on the proposed exemption in §§117.103(d), 117.203(c), and 117.473 for combustion units which would meet the requirements of a standard permit currently being developed for electricity-generating combustion units rated at less than ten MW and which emit no more than 0.015 lb NO_x/MMBtu heat input. The EPA stated that in order for it to consider a source to be exempted from Chapter 117, the commission should submit the standard permit to the EPA for approval as a SIP revision because this essentially provides a procedure to obtain an alternate means of control. The EPA stated that as such, the alternate method must be part of the SIP. TXU supported the development of a standard permit for electricity-generating combustion units rated at less than ten MW, while Sierra-Houston stated that all sources with NO_x emissions of ten tpy or more should be subject to the ESADs.

Regarding the Sierra-Houston comment, the commission notes that a ten MW site at the 0.23 pound per MW-hour rate would only emit ten tpy if it operated for the full year, so any project exceeding ten tpy would have to obtain an NSR permit rather than the proposed standard permit. The commission notes that the NSR permitting requirements of Chapter 116 are part of the SIP and therefore are federally enforceable. The commission has changed "less than 10 MW" in §§117.103(d), 117.203(c), and 117.473 to "no more than 'ten MW' for consistency with the new standard permit for small electric generating units currently being developed. In addition, because the term "distributed generation of electricity" is not defined, the commission has replaced this term with the more descriptive wording "small (ten MW or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric

grid." This exemption is intended to provide an incentive for installation and use of new clean energy-producing technology. The emission limit of the proposed standard permit is consistent with the adopted ESAD of 0.015 lb NO_x/MMBtu heat input.

BCCA, TCC, and Union Carbide expressed concern that the use of ammonia in post-combustion controls will trigger more complex permitting requirements due to increased ammonia emissions, and will likely increase the pre-construction lead-time. BCCA stated that this, in turn, shortens the total amount of time available to install the controls, resulting in more unscheduled equipment downtimes and economic burden to the region that must be considered in the selection of controls. BCCA encouraged the commission to consider and authorized these more complex permitting activities through the rulemaking process and not on a case-by-case basis. TCC requested confirmation that the installation of ammonia storage and handling facilities associated with SCR qualifies for Standard Permits for Pollution Control Projects authorized in 30 TAC §116.617.

The Standard Permit for Pollution Control Projects in 30 TAC §116.617 should be available for use by SCR projects, and the review time period is 30 days. 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 the increased permitting time referenced provided that the ammonia emissions from the storage, handling, and slip do not

create any health concerns.

Solar Turbines stated that some turbines can only be retrofitted with dry low-NO_x systems after they are uprated as part of a major overhaul process and expressed concern that uprating could trigger NSR permitting requirements.

If "uprating" increases the unit's production capacity, then the owner or operator must satisfy the requirements of §116.617(5), which could require the owner or operator to not utilize the production capacity increase until the necessary authorization under §116.110 or §116.116 is obtained.

DEFINITIONS

As described earlier in this preamble in the *TECHNICAL FEASIBILITY - AUXILIARY BOILERS* section, the commission has revised the definition of auxiliary steam boiler in §117.10(3) to clarify that 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.

Phillips 66, TCC, and TxOGA commented on the proposed definition of "EGF" in §117.10(11). Phillips 66 and TxOGA stated that this definition appears to include cogeneration units and questioned whether this was the intent. Phillips 66, TCC, and TxOGA objected to the inclusion of cogeneration units. Phillips 66 and TxOGA recommended the definition be revised to include a percentage of "sales to the grid" and regulation by the PUCT as a threshold within the definition. TCC recommended that

cogeneration units at petrochemical plants only be subjected to the mass emissions cap and trade program for consistency, ease of implementation, and clarity for operators.

The definition of EGF includes cogeneration units. Cogeneration turbines generate power which in some cases is sold to the grid and in other cases is entirely dedicated to use by a manufacturing process. Cogeneration units 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 cogeneration units should comply with the daily cap. Cogeneration turbines which provide power to a dedicated industrial load may provide power to the grid only when the manufacturing process is not operating. This type of operation is not adding additional emissions during peak electric demand and ozone periods. The commission has modified the system cap requirements in §117.210 to exclude cogeneration units whose electric output entirely serves one or several dedicated industrial customers, except when the industrial customers are not operating. These sources are base load sources 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, these sources are more similar to electric generating units located at an industrial site which do not generate electricity for compensation. Because these industrial electric generators do not provide electricity for peaking, they were never included in the system cap for the reasons described in the previous paragraph. In a future rulemaking, the commission may develop system cap trading rules for EGFs in HGA which would enable trades to occur among companies. This development would ensure the flexibility of cap and trade compliance.

KTC, Phillips 66, TCC, and TxOGA stated that a definition of “incinerator” should be added to §117.10 that is consistent with the definition of the existing definition in §101.1, or the commission should clarify that the use of this term in Chapter 117 is consistent with the definition in §101.1. KTC also suggested the addition of a definition of "thermal oxidizer" in §101.1. KTC, Phillips 66, TCC, and TxOGA stated that control devices such as vapor combustors and thermal oxidizers should be clearly unregulated by the proposed rules. Similarly, Phillips 66 and TxOGA stated that tail gas incinerators controlling sulfur recovery units (SRUs) are not incinerators as defined in §101.1, but are similar to flares. Phillips 66 and TxOGA requested clarification that tail gas incinerators controlling SRUs are part of the SRU and therefore unregulated by the proposed rules.

As discussed earlier in the *TECHNICAL FEASIBILITY - INCINERATORS* section of this preamble, the commission identified incinerators (including enclosed control devices that combust or oxidize gases or vapors (e.g., vapor combustors and thermal oxidizers)) with more than 40 MMBtu/hr design heat input and BIF units as the largest NO_x emission sources within the category of waste combustion devices. The commission confirms that tail gas incinerators controlling SRUs are part of the SRU and therefore are unregulated by the adopted rules. Although the term "incinerator" is defined in §101.1 to refer to units which burn wastes for the primary purpose of reducing volume and weight, this term has also been used to refer to enclosed control devices that combust or oxidize gases or vapors. The ESADs for incinerators apply to both types of units. Therefore, the commission has added a definition to §117.10 to clarify that for the purposes of Chapter 117, the term "incinerator" includes both enclosed control devices that combust or oxidize gases or vapors, and incinerators as defined in §101.1. The new definition

is not a substantive change from how this term is intended to be used in Chapter 117, and its inclusion in the adopted rule will provide clarity. Subsequent definitions in §117.10 were renumbered due to the addition of the definition of "incinerator." Because "fume abaters" (meaning enclosed control devices that combust or oxidize gases or vapors (e.g., vapor combustors and thermal oxidizers)) are now clearly included in the new definition of "incinerator" in §117.10, the commission has replaced the reference to incinerators (including fume abaters)" with a reference to "incinerators" in §§117.201(12), 117.203(a)(4), and 117.206(c)(16).

Sierra-Houston commented on the definition of "low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit." Sierra-Houston stated that the heat input cutoff should be lowered to 1.0 (10^{11}) Btu per year. Sierra-Houston also commented on the definition of "low annual capacity factor stationary gas turbine or stationary internal combustion engine" and stated that the operating hours cutoff should be lowered from 850 to 500 hours per year.

The commenter is apparently suggesting these changes in the belief that these units are exempt from the ESADs for HGA. However, low annual capacity factor units at major stationary sources of NO_x in HGA are subject to the ESADs, and therefore the commenter's suggested changes would have no impact on these units. The commission has made no change in response to the comments.

Rhodia commented on the definition of "major source" in §117.10 and questioned whether NO_x emissions from exempt sources are included in determining a "major source" classification.

For HGA, the definition of "major source" includes any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit at least 25 tpy of NO_x. Therefore, NO_x emissions from all stationary sources or groups of sources are included in determining a "major source" classification.

TCC stated that a definition for "reheat furnace" should be added to the rule because some equipment, such as reboilers, could be considered a “reheat” furnace. TCC stated that the commission should clarify whether such equipment is considered a “reheat” furnace. Wyman-Gordon suggested that definitions of “heat treat furnace” and “reheat furnace” be added.

The commission agrees that definitions of “heat treat furnace” and “reheat furnace” are needed to clarify the units to which the rule applies, and has added definitions of these terms to §117.10 accordingly. The new definitions are not a substantive change from how these terms are intended to be used in Chapter 117, and their inclusion in the adopted rule will provide clarity. Subsequent definitions in §117.10 were renumbered due to the addition of the definitions of “heat treat furnace” and “reheat furnace.” In addition, the commission changed "furnaces" to "metallurgical furnaces" in §117.206(c)(14) for additional clarity.

MISCELLANEOUS RULE LANGUAGE COMMENTS

Phillips 66 and TxOGA stated that the rule is poorly formatted and difficult to read and understand. In particular, Phillips 66 and TxOGA commented that the exceptions to some exemptions made the rule difficult to follow. Phillips 66 and TxOGA also stated that the proposed rule language contained a

number of typographical errors and incorrect citations and equations.

Phillips 66 and TxOGA did not identify the specific errors in the proposed rule language. The commission has made every effort to eliminate errors and improve the readability of the rule.

TXU supported the addition of §117.105(l) which specifies that RACT limits will no longer apply after the emission specifications of §117.106 become applicable. TXU stated that this provision will avoid potential confusion and unnecessary overlap of rules when the more stringent requirements of §117.106 go into effect.

The commission appreciates the support. As a result of several changes to the rules as proposed, the schedule of reductions required by the adopted HGA mass emissions cap has been lengthened for a number of sources currently subject to the RACT limits. The language in §117.105(l) and §117.205(i) has been modified to specify that the RACT emission specifications are effective until the emissions allocation for a source under the HGA mass emissions cap are equal or less than the allocation that would be calculated using the RACT emission specifications.

Sierra-Houston stated that §117.107, concerning Alternative System-Wide Emission Specifications, should be repealed.

No changes were proposed to §117.107. Therefore, this comment is beyond the scope of this rulemaking. However, it should be noted that §117.106(e)(3) specifically prohibits use of §117.107

in HGA as an alternative method of compliance with the NO_x emission specifications of §117.106. Consequently, the suggested change is unnecessary in HGA.

TCC stated that the language in §117.206(d) and (f)(4) concerning NO_x averaging and compliance flexibility is confusing and should be revised.

The commission believes that the language of §117.206(d) and (f)(4) is relatively straightforward. Specifically, the owner or operator of affected units in HGA must use the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3, as opposed to complying on a rolling 30-day average or block one-hour average, as is the case in BPA and DFW. However, EGFs in HGA must also comply with the daily and 30-day system cap emission limitations of §117.210, which is modeled on the existing system cap in §117.108. Finally, an owner or operator in HGA may not use §§117.207, 117.223, and 117.570 to comply with the ESADs of §117.206(c).

TCC commented on §117.211 and stated that the initial demonstration of compliance is unnecessarily onerous, that the existing NO_x final control plans should have all the necessary data with the exception of exempt sources, and that consequently an initial demonstration of compliance should be required only for previously exempt sources.

For sources in the mass cap and trade program for HGA, the test requirements of §117.211 are used to determine emission factors for units not required to install a NO_x monitor. The ESADs will require most unmonitored sources to reduce emissions. For most sources, it will be to the

owner's advantage to sample emissions after installation of control equipment in order to develop a lower emission factor for that source. However, to ensure that all emission factors are grounded on actual source measurement by the compliance deadline, all units must be tested at least once under §117.211 by December 31, 2006. It is possible that a few sources will be able to demonstrate compliance with the mass cap and trade program using an emission factor based on source testing developed for the November 1999 NO_x RACT final control plans.

TCC commented on §117.216(c) and stated that references to §117.520(a) and (b) should be to §117.520(a), (b), and (c).

The commission has revised §117.116 and §117.216 to exclude sources in HGA since the testing and monitoring of §117.114 and §117.214, in conjunction with the requirements of the mass emissions cap and trade program, will be sufficient to determine compliance. Therefore, the suggested change is unnecessary.

Union Carbide commented that §117.219(d) and the requirements of §§117.206(f), 117.213(k)(2), and 117.206(e)(1)(A) appear to be inconsistent. Union Carbide requested clarification of the actual data that is needed to demonstrate compliance. TCC suggested that §117.219 be revised to require "annual" rather than "semiannual" reporting frequency consistent with the NO_x mass cap and trade reports.

The excess emissions report is applicable for sources complying with specific emission limits, either NO_x RACT, the emission specifications for the BPA and DFW attainment demonstrations,

or sources monitoring CO emissions under §117.206(e)(1)(A). The concept of excess NO_x emissions has been modified under the HGA cap and trade program and is now addressed in Chapter 101. Chapter 117 retains the emissions monitoring requirements for the HGA cap and trade program. Maintaining a semiannual report requirement, which identifies periods during which the monitoring system was inoperative and the nature of system repairs or adjustments, will help assure the effectiveness of the cap and trade program. The commission has reduced the semiannual report requirements of §117.219(d) for sources in the HGA mass emissions cap and trade program that are not subject to (or no longer subject to) §117.205 to a monitoring system report.

Union Carbide stated that the recordkeeping requirements in §117.219(f) should incorporate some data reduction measures that will allow for hourly data to be consolidated to a daily value for long-term storage similar to what is allowed under 40 CFR 63.152(f). Union Carbide stated that keeping hourly data for five years for each source can be burdensome.

Because §117.219(f) specifically allows the records to be electronic, the commission does not believe that the records are burdensome. The commission has clarified §117.219(f)(2) by adding a new subparagraph (C) for units subject to the mass emissions cap and trade program since compliance with the ESADs in HGA will be on an annual basis. However, EGFs subject to the system cap of §117.210 additionally will be required to keep daily records under §117.219(f)(2)(B). The commission may review the monitoring, reporting, and recordkeeping requirements for the HGA cap and trade program in the future. Some of the procedures in 40 CFR 163(f) could be

considered at that time.

EMISSION SPECIFICATIONS - GENERAL

Sierra-Houston stated that the emission specifications for BPA in §117.106(a) and §117.206(a) should be made equivalent to those for HGA because HGA and BPA are adjacent to each other, need equivalent emission reductions, and contribute to each other's air pollution and that of DFW through transport.

No changes were proposed to the Chapter 117 NO_x limits for sources in BPA. Therefore, this comment is beyond the scope of this rulemaking. However, the commission may, in the future, develop additional control measures for BPA upon a determination that additional emission reductions are needed from BPA sources.

Pasadena/Donohue stated that §117.206(c) should be moved to a new section titled “Emission Factors for the Allocation of Allowances under the Mass Emissions Cap and Trade Program” to avoid any misinterpretation that these standards are to be met on a unit-by-unit basis.

The commenter's suggestion is a good one. However, the commission cannot make the suggested change due to APA requirements, which do not allow for the creation of a new section upon adoption of a rule proposal. Nevertheless, the commission believes it is clear that the ESADs in HGA are used to set the allocations for the mass emissions cap and trade program.

Calpine and RMT stated that the phrase "the lower of any applicable permit limit" in §117.206(c) should be removed for consistency with §101.353. Calpine and RMT stated that this is necessary to avoid penalizing those sources already emitting or authorized to emit at levels equal to or lower than the limits in §117.206(c).

A few new EGF permits for combined cycle gas turbine plants have been issued or are under review at 3.0 or 3.5 ppmv NO_x. These commitments have been made as part of the permit applications and have been relied on to enable the projects to meet the nonattainment new source review (NNSR) permitting requirements applicable in HGA. To allow the facilities a higher emission level under the cap and trade program would windfall those facilities with allowances and increase the overall levels of emissions in the cap. To hold these facilities to their emission commitments is not penalizing them. In addition, under the adopted cap and trade rules, these new facilities will not be required to buy in to the cap to operate. This approach serves to minimize the potential 23 tpd of NO_x emissions from new permitted sources that was not identified in the SIP proposal because this work was not completed by commission staff until after the rules were proposed in August. Minimizing this increase is an important element of achieving an approvable SIP for HGA. The commission has revised §101.353 to be consistent with Chapter 117 on this matter.

The EPA commented that the proposed language in §117.206(c) and §117.475(a) and (b) uses “the lower of any applicable permit limit or the emission limit” in Chapter 117. The EPA stated that if a source relies upon a permit, the commission must have issued that permit through a permit process

approved by the EPA as part of the Texas SIP.

The commission notes that the NSR permitting requirements of Chapter 116 are part of the SIP and therefore are federally enforceable. In addition, permits by rule which are authorized by Chapter 106 are likewise federally enforceable. Specifically, "permit by rule" replaced "standard exemption" due to the requirements of SB 766, which amended the TCAA and created "permits by rule." Prior to passage of SB 766, the commission had the authority under TCAA, §382.057, to exempt from permitting requirements, changes within any facility and certain types of facilities that would not make a significant contribution of air contaminants to the atmosphere. In order to remove the appearance that these insignificant facilities were exempt from environmental regulation in addition to being exempt from permitting, the new TCAA, §382.05196 gives the commission the authority to adopt permits by rule for certain types of facilities that will not make a significant contribution of air contaminants to the atmosphere. On August 9, 2000, the commission adopted revisions to 30 TAC Chapter 106 in order to use permits by rule to authorize new construction and/or modifications or changes (25 TexReg 8653 (September 1, 2000)). On August 13, 1982, (47 Federal Register 35183), the EPA published its approval of several revisions to 30 TAC Chapter 116 that were submitted to the EPA for SIP approval on May 9, 1975. Part of that May 9, 1975 submittal included §116.6, Exemptions. Although §116.6 has since been revised, the version that existed at the time of the August 13, 1982 SIP approval has not been withdrawn from the SIP. Thus, the basic regulatory authority for exemptions, now permits by rule, is in the SIP. In a letter dated June 4, 1990 from Merrit Nicewander, Chief, New Source Review Section, EPA Region VI, to Lawrence Pewitt, Director of the Permits Division of the Texas Air Control

Board (TACB, predecessor to the commission), the EPA stated that where the TACB issues standard exemptions pursuant to state regulations that were developed in accordance with the Texas SIP, the standard exemptions themselves are federally enforceable. Thus, since permits by rule are federally enforceable, companies may rely upon them in order to meet the requirements of §117.206(c) and §117.475(a) and (b).

TCC noted that §117.221 limits the alternative case specific specification to ammonia and carbon monoxide limits, and suggested that the rule be revised to allow companies to submit an alternative case specific specification for NO_x in §117.221. TCC stated that this is necessary due to the uncertainty associated with the proposed NO_x limits. Solutia and TCC stated that the regulated community needs a case-by-case determination for NO_x limits if they cannot demonstrate compliance despite best efforts and that the commission should address how they expect to handle such situations.

The commission does not believe that case-by-case determinations for NO_x limits are appropriate because the adopted Chapter 117 revisions include flexibility. Specifically, 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 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 rule proposal preamble, 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 ESADs.

SYSTEM CAPS

Dynegy stated that the daily and 30-day system cap limited the flexibility of the mass emissions cap and trade program. BCCA, Entergy, PECO, TCC, TIP, and TxOGA similarly objected to the daily and 30-day system cap. Phillips 66, TCC, and TxOGA suggested that EGFs whose primary purpose is to supply steam and electricity to an industrial facility be exempt from the daily and 30-day system cap

and subject only to an annual limit. Calpine suggested that participation in the system cap of §117.210 be made voluntary for each "qualifying facility," as defined in 40 CFR 72.2, due to continual obligations to provide steam and electric power, which limits the ability to control activity level and take advantage of the system cap. Sierra-Houston objected to the proposed system cap and stated that system caps do not result in maximum NO_x reductions from every unit.

The commission disagrees with the comments and has made no change to the rules. 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 harder 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.

As described earlier in the *DEFINITIONS* section of this preamble, the commission has modified the system cap requirements in §117.210 to exclude cogeneration units whose electric output entirely serves one or several dedicated industrial customers, except when the industrial customers are not operating. These sources are base load sources 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, these sources are more similar to electric generating units located at an industrial site which do not generate electricity for compensation. Because these industrial electric generators do not provide electricity for peaking, they were never included in the system cap for the reasons described in the previous paragraph.

The commission disagrees that these daily and monthly limits render the ability to trade meaningless because trading can still be useful to meet annual limits. As discussed in a previous response, in a future rulemaking, the commission may develop system cap trading rules for EGFs in HGA which would enable trades to occur among companies. This development would enhance the flexibility of cap and trade compliance.

REI commented that under §117.108(c)(1), a baseline heat input is proposed for calculation of a 30-day rolling average system cap using the "system highest 30-day heat input in the nine months of July, August, and September 1997, 1998, 1999." REI proposed that the phrase be changed to "*any* system 30-day heat input, *specified by an owner or operator*, in the nine months of July, August, and September 1997, 1998, 1999" to provide the flexibility for systems to choose a period other than that corresponding to the system highest heat input. (REI's emphasis supplied). Crown and TCC expressed

concern about the use of the 1997 - 1999 period in the system caps of §117.108(c)(1) and §117.210(c)(1). Crown stated that this could limit throughput to the levels experienced in these years. Chevron suggested that the 30-day system cap be based on the highest six-month fired duty in 1995 - 2000. As an alternative, Chevron suggested that the average actual firing rates for units in non-turnaround months of the affected year be substituted for times that the unit is in a major scheduled shutdown or turnaround mode. PECO and an individual stated that the provisions for determining a 30-day system cap do not include a method for determining the system cap emissions for sources that did not operate between 1997 and 1999. PECO suggested that the following language be added to the H_i definition in §117.210(c)(1): "For EGFs constructed after January 1, 1999, authorized daily heat input may be used."

The 30-day system cap limit based on historical operations assures that reductions are achieved below actual historical levels. The years 1997 - 1999 were selected because use of the 1997 emissions inventory is consistent with the photochemical modeling analyses of NO_x point source emissions in support of the HGA ozone attainment demonstration, which are based on 1997 emissions. The system cap includes 1998 and 1999 to address concerns about fluctuations in activity level from year to year. The months of July, August, and September were selected because these three months typically represent the highest demand for electricity and, not coincidentally, include hot summer days when ozone is most likely to form. In summary, the baseline of the system highest 30-day heat input in the nine months of July, August, and September 1997, 1998, and 1999 represents recent highest utility electric demand and emissions during the peak ozone formation months. The commission agrees that the provisions for

determining a 30-day system cap should include a method for determining the system cap emissions for sources which were not in operation prior to January 1, 1997. Consistent with the cap and trade provisions of §101.353(a), the commission has revised the H_i definition in §117.108(c)(1) and §117.210(c)(1) to address these sources in HGA.

Sierra-Houston commented on §117.108(i) and objected to allowing permanently retired or decommissioned EGFs to be used in a system cap emission limit. Sierra-Houston stated that this does not result in maximum NO_x reductions from every unit.

Only shutdowns that occurred after the modeled emission inventory are included in the system cap. This provides an incentive for the replacement of higher-emitting EGFs with much-cleaner EGFs, thus resulting in progress toward attainment of the ozone NAAQS. The commission has made no change in response to the comment.

EXEMPTIONS

BCCA, Calpine, NASA, PECO, REI, RMT, TGC, and TGP suggested that a new exemption be added for low annual capacity factor units. BCCA, NASA, Pasadena/Donohue, PECO, REI, and TGP stated that the retrofit of combustion controls and SCR is not economically reasonable for certain low-capacity factor applications. BCCA and REI stated that a number of local air districts in Southern California have regulations which allow for lesser NO_x control requirements for gas turbines with limited operation, and that the commission should consider the approach used in SCAQMD Rule 1134 which recognizes retrofit consideration issues associated with gas turbines of different sizes and applications.

BCCA stated that SCAQMD exempts low capacity factor turbines, laboratory gas turbines used in research and testing, gas turbines operated exclusively for fire fighting and/or flood control, chemical processing gas turbines, emergency standby and peaking gas turbines demonstrated to operate less than 200 hours per calendar year, existing gas turbines rated below 4.0 MW and operated less than 877 hours per year, etc.

The commission has evaluated the comments and has included exemptions in the adopted rules 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. As described earlier in this preamble in the *TECHNICAL FEASIBILITY - AUXILIARY BOILERS* section, the commission has added an alternative ESAD as new §117.106(c)(4) based on Tier I controls. The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for auxiliary boilers, utility boilers, and stationary gas turbines 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.

Regarding IC engines, the commission has added a new paragraph (10) to §117.203(a) which exempts diesel-fired engines. This will address emergency diesel-fired generators. The commission notes that §117.203(a)(6)(A) exempts stationary gas turbines and engines which are used in research and testing, or used for purposes of performance verification and testing, or used solely to power other engines or gas turbines during start-ups, or operated exclusively for firefighting and/or flood control, or used in response to and during the existence of any officially declared disaster or state of emergency, or used directly and exclusively by the owner or operator

for agricultural operations necessary for the growing of crops or raising of fowl or animals, or used as chemical processing gas turbines. However, in the future, the commission may pursue requirements for these currently-exempt engines in HGA to prevent emissions increases from these engines if operated in peak shaving mode, or to address their emissions if additional reductions are determined to be necessary to reach attainment with the ozone NAAQS.

The commission has also added new §117.206(c)(17) and §117.475(c)(3), which provide low annual capacity factor units with an alternative to the emission specifications in §117.206(c)(1) - (16). The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units 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. This alternative ESAD will address low-capacity factor applications which do not qualify for the stationary gas turbine and engine exemptions described in the previous paragraph.

TCC and Union Carbide stated that the 850 hour per year exemption should be retained rather than eliminated. Phillips 66 and TxOGA stated that the 850 hour per year exemption for stationary IC engines should be reduced to 250 hours per year, while Texas Eastern suggested a cutoff of 200 hours per year. Sierra-Houston stated that the 850 hour per year exemption should be reduced to 500 hours per year and that only stationary IC engines of less than 100 hp should be exempt. Pasadena/Donohue suggested that the 850 hour per year exemption be retained and that only stationary IC engines of less than 250 hp be exempt. Pasadena/Donohue also suggested that an exemption be added for engines which are operated during maintenance and repair activities. Texas Eastern, TGC, and TGP stated that

compliance with the 0.17 g/hp-hr NO_x emission specification on engines with low utilization rates or lower emission rates during the baseline years will result in large capital expenditures with minimal NO_x reductions. Dynegy and Pasadena/Donohue suggested the inclusion of an exemption from the emission specifications and monitoring requirements for emergency generators which are used solely in the event of a power outage. Pasadena/Donohue stated that it has an engine which must be used during power outages to rotate a lime kiln to keep the hot lime from warping the bottom of the kiln. Phillips 66, Spring Valley, TCC, Texas Eastern, and an individual stated that firewater pumps and emergency electrical generators are used only a small portion of the time, and therefore the emissions will only be a small portion of the total potential emissions and should be exempt. TCC stated that companies must maintain the reliability of emergency equipment designed for use in the event of a catastrophic incident and that reliable, voluntary testing of emergency back-up or standby equipment should be encouraged rather than discouraged. Spring Valley and an individual suggested that testing of engines should be restricted from operating between 6:00 a.m. and noon. TCC also stated that the commission should clarify that testing of emergency equipment is already exempt per §117.203(a)(6)(A) and the potential loss of the 850 hour per year exemption in no way impacts the testing of this equipment. In addition, TCC stated that the commission should also clarify that the exemption applies to gas turbines, engines, and other infrequently used equipment, and that these sources also should be exempt from continuous monitoring requirements. GPA and Solar Turbines recommended an exemption for gas turbines rated at less than ten MW. Solar Turbines also suggested the inclusion of a dollars per ton exemption threshold, to be set no higher than that found acceptable under NO_x RACT rules or that used in developing NO_x SIP rules. Spring Valley and an individual suggested that engines that are exempt from the Chapter 117 requirements be subject to the California spark-ignition engine requirements of

§114.421 and §114.422.

As noted earlier in this preamble, the commission has added exemptions for certain stationary gas turbines and engines. Section 117.203(a) specifically states that units which qualify for exemption under this subsection are "exempted from the provisions of this division," which includes the CEMS and PEMS requirements. As noted earlier in this preamble, the commission has added a new §117.206(c)(17), which provides low annual capacity factor units with an alternative to the emission specifications in §117.206(c)(1) - (16), and has also added an additional ESAD to §117.106(c)(2) for auxiliary boilers, utility boilers, and stationary gas turbines based on Tier I controls. In the future, the commission may pursue emission reductions from exempt sources in HGA if additional reductions are determined to be necessary to reach attainment with the ozone NAAQS. Similarly, the commission may pursue in future rulemaking the suggestion that testing of the engines should be restricted from operating between 6:00 a.m. and noon.

The commission disagrees with the suggested concept of including a maximum cost (in dollars per ton of NO_x reduced) in the rules. Such a concept would not ensure that the necessary emission reductions occur. In addition, the concept raises numerous issues such as the calculation methodology, enforceability, and especially the cutoff level. For example, the commission is aware of one company that spent approximately $31,000 per ton to comply in an ozone nonattainment area while the company was in Chapter 11 bankruptcy.

TECO commented on the proposed emission specification for dual-fuel engines in §117.206(c)(9)(C)

and stated that it operates a 6.0 MW dual-fuel engine/generator unit to provide electricity during times of reduced reliability of the REI commercial power grid. TECO stated that the engine has operated from 219 to 444 hours per year in 1997 - 1999 and that it would cost $111,877 per ton to add SCR to this engine and might render the unfired waste heat recovery boiler inoperable. TECO stated that its dual-fuel engine/generator furnishes electricity to a variety of medical buildings, and that future growth could result in the building owners installing individual engines which would produce less than ten tpy and therefore would not be subject to the proposed Chapter 101 mass emissions cap and trade program. TECO stated that these individual engines would produce 6.0 - 8.0 g/hp-hr of NO_x, resulting in greater emissions compared to its one large engine. TECO suggested that an exemption be added to §117.203 for dual-fuel engines at "District Energy Plants" which run less than 850 hours per year.

Engines which are used to shave peak electric demand tend to operate on hot days that coincide with higher probability of ozone exceedances. The commission does not agree with the suggestion to exclude this source from the cap and trade program entirely. Uncontrolled, the 8,338 hp engine has the potential to emit 1.3 tpd of NO_x, but under the cap and trade program, the low historical usage of this engine would limit the NO_x emissions, regardless of the emission specification. The reported NO_x emissions for the engine were 11.3 tpy over the year in 1997, and 0.018 tpd over the June - August, 1997 period used in the attainment demonstration modeling.

The commission has adopted two standards for dual-fuel engines. The adopted ESAD of 0.5 g/hp-hr would apply to any dual-fuel engine placed into service after December 31, 2000. The adopted 5.83 g/hp-hr ESAD would apply to engines that were placed into service before December

31, 2000. The TECO engine, the only dual-fuel stationary engine in the HGA point source inventory, would be subject to the 5.83 g/hp-hr standard, which is the emission factor used to calculate TECO's emissions in 1997. This results in the TECO engine being included in the cap and trade compliance program at its historical emission factor and activity level, so it will not be required to reduce emissions, but it will not be given allowances to increase them, either. By capping the emissions at this level and requiring TECO to find other ways to reduce emissions if the engine is to increase its emissions, the source, which contributes to ozone exceedances, is also required to be part of the attainment strategy.

It has come to the commission's attention that the proposed §117.103(a)(2) inadvertently included a comma after the term "utility boiler" that should have been deleted when the term "steam generator" was deleted. The commission has revised §117.103(a)(2) to remove this comma.

TXU supported the proposed revision to §117.103(c)(1) which would extend the oil-fired emergency exemption provisions of §117.105 to the emissions specifications of §117.106 and §117.108 for EGFs. TXU stated that this provision will help maintain electric reliability during critical periods of gas supply interruption. NASA and TCC stated that a similar exemption should be added to §117.203 to suspend fuel oil firing emission specifications for industrial boilers, process heaters, and furnaces during these same emergency operating conditions.

The commission agrees with TXU that the purpose of the oil-fired emergency exemption provisions of §117.103(c)(1) is to help maintain electric reliability during critical periods of gas

supply interruption. Gas curtailments are most likely to occur during extended periods of sub-freezing weather, and it is important during such times to maintain the reliability of the electric grid to ensure that human health is not endangered by lack of heat due to unavailability of electricity. There is no corresponding need during these same emergency operating conditions for industrial boilers, process heaters, and furnaces to continue operating. Therefore, the commission disagrees with NASA and TCC and has made no change in response to the comments.

Solutia and TCC suggested that addition of an exemption in §117.203 for startup or regeneration heaters operated less than 850 hours per year. Solutia and TCC stated that this equipment is used only a small portion of the time, and therefore, the emissions will only be a small portion of the total potential emissions. As an example, Solutia and TCC stated that process startup heaters used to preheat systems prior to introducing feeds operate for a short period of time for a startup which generally occurs a few times a year. Solutia stated that it has five startup heaters ranging in size from 11 to 75 MMBtu/hr heat input, each operating less than 850 hours per year.

As noted earlier in this preamble, the commission added a new §117.206(c)(17), which provides low annual capacity factor units with an alternative to the emission specifications in §117.206(c)(1) - (16). The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units 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.

Chevron suggested that the exemption in §117.203(a)(9) for boilers and process heaters be revised from

2.0 MMBtu/hr to ten MMBtu/hr due to the high cost of FGR and SCR in these small units. Chevron also questioned the feasibility of installing SCR and FGR on these units. TCC suggested that the exemption be revised to 15 MMBtu/hr, or alternatively, that all boilers and process heaters rated at less than 40 MMBtu/hr should be exempt because these sources make up a large percentage of total units but a small percentage of total NO_x emissions.

Currently, boilers and process heaters rated at less than 2.0 MMBtu/hr are regulated under Chapter 117. The commenters' suggested changes would result in a gap in coverage for some or all boilers and process heaters between 2.0 and 40 MMBtu/hr. The boilers and process heaters in HGA are almost entirely gas-fired. FGR has been demonstrated to be an effective control technology for these sources, based on experience with BACT NO_x limits, retrofit requirements in California, and information in the literature. Fuel trim has been demonstrated as an effective control technique for natural gas fired boilers operating with FGR to achieve compliance with a 30 ppmv NO_x limit. The combination of FGR to achieve NO_x compliance with variable speed fans and upgraded boiler operating controls has improved fuel efficiency and combustion stability. The commission has made no change in response to the comments.

It has come to the commission's attention that the exemption for ICI boilers and process heaters with a maximum rated capacity of less than 40 MMBtu/hr in the proposed §117.205(h)(9) is unnecessary because these units are already exempt under the existing §117.205(h)(1). Therefore, the commission has deleted the proposed §117.205(h)(9) and renumbered the proposed §117.205(h)(10) and (11) as §117.205(h)(9) and (10). The commission has also revised references

to these rules in §117.213 to reflect their renumbering.

TCC and Union Carbide stated that §117.206(c)(1)(C) and §117.206(c)(8)(C) should be revised to exclude boilers and process heaters with a maximum rated capacity of 2.0 MMBtu/hr or less.

An exemption has been added for these small boilers and process heaters as new §117.203(a)(9). Therefore, the suggested change does not appear to be necessary.

Phillips 66, TCC, and TxOGA suggested the addition of an exemption from the CO limits for boilers operated in hot-standby mode, as indicated by low load and high stack oxygen concentration (greater than 15% O_2). Phillips 66 and TxOGA considered "low load" to be less than 1.0% of maximum, while TCC considered "low load" to be less than 5.0% of maximum. TCC stated that combustion sources such as boilers, process heaters, and pyrolysis furnaces equipped with multiple low-NO_x burners have difficulty meeting the Chapter 117 CO emissions limit during periods of hot-standby operation. TCC stated that hot-standby operations are those periods during which only a very few burners are in operation, when fired duty may be as low as 1.0 - 5.0%. TCC stated that during periods of hot-standby, stack oxygen is nearly always over 15%, and averages about 20%. TCC stated that the uncorrected CO concentration averages about 35 - 75 ppm for some boilers, and as low as 0.5 to 8 ppm for some furnaces, and that the CO concentration corrected to 3% O_2 may average from over 300 ppm to over 600 ppm. Solutia similarly suggested an exemption or revised emission standard for such boilers. TXI stated that 15% O_2 is typical in lightweight aggregate kiln stack emissions. TXI commented that EPA MACT regulations specify 7.0% O_2 in stack emissions from hazardous waste

kilns, and stated that use of a 3.0% O_2 level to correct CO emissions from lightweight aggregate kilns would be unreasonable.

The commission agrees that certain units typically will operate with high excess O_2 which will drive the CO level, when corrected to 3.0% O_2, to a high level. These units include boilers and process heaters operating at less than 10% of maximum load with stack O_2 in excess of 15% (i.e., "hot-standby" mode), and lightweight aggregate kilns. Accordingly, the commission has revised §117.206(e) to exclude these units from correcting CO to 3.0% O_2. Other units which were excluded from the CO limit of §117.206(e) if they are already subject to CO limits in other rules include stationary IC engines in BPA and DFW, BIF units, and certain incinerators, as described in the *AMMONIA AND CO EMISSIONS* section of this preamble. It should be noted that approvals of an alternate CO limit are available under §117.221 and can be done without EPA involvement (i.e., no case-specific SIP revision needed) since the commission is not including these approvals in the attainment demonstration SIP.

Dynegy suggested the addition of an exemption for major sources to be modeled after the exemptions for minor sources in the proposed §117.473(a)(2)(A) and (b).

The exemption available for minor sources in §117.473(b) does not apply to sources which are subject to the mass emissions cap and trade program. Since all major sources are subject to the mass emissions cap and trade program, it would be inappropriate for the exemption available for minor sources in §117.473(b) to also apply major sources. Regarding the exemption available for

minor sources in §117.473(a)(2)(A) for engines rated at 50 hp or less, the commission has not included a similar exemption in §117.203 for major sources in order to ensure that the universe of equipment outside the cap at major sources is minimized. This is necessary to achieve NO_x reductions which come as close as possible to the 90% target described earlier in this preamble. Nevertheless, as noted earlier in this preamble, the commission added a new §117.206(c)(17), which provides low annual capacity factor units with an alternative to the emission specifications in §117.206(c)(1) - (16). The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units 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.

Calpine and RMT stated that a new §117.206(h) should be added to provide an exemption from §117.206(c) for sources in HGA that emit less than ten tpy units in order to mesh with the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3.

The applicability of §117.206(c) is specified in §117.201, which states that Subchapter B, Division 3 (Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) applies to the listed units "located at any major source of nitrogen oxides" in BPA, DFW, or HGA. For HGA, "major source" is defined in §117.10 as any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit at least 25 tpy of NO_x. Sources that emit less than 25 tpy of NO_x are regulated under Chapter 117, Subchapter D, concerning Small Combustion Sources. Section 117.475 spells out the two compliance approaches available for sources which emit less than ten tpy, either direct

compliance with the emission specifications, or compliance through the mass emissions cap and trade program in Chapter 101.

TGP commented that under §117.475(c)(2), stationary IC engines greater than 50 hp would have to meet an emission specification of 0.50 g/hp-hr. TGP stated that there may be more than 1,000 emergency generators, located at most office buildings, high-rise residences, country clubs and hotels, that would have to meet this emission specification. TGP stated that emergency generators usually do not operate more than 100 hours per year and recommended the addition of an exemption under §117.473(a)(2)(H) for "portable and emergency engines and turbines as defined under §106.511."

The emission standard for stationary reciprocating IC engines is intended to apply only to gas-fired engines. The commission has added "gas-fired" to §117.475(c)(2) to clarify this standard and has added a new subparagraph (I) to §117.473(a)(2) which exempts diesel-fired engines. The commission agrees that an exemption for gas-fired emergency generators is appropriate and has revised §117.473(a)(2) accordingly to include an exemption for emergency generators that do not operate more than 100 hours per year. The commission has added a new subsection (h) to §117.479 which specifies the recordkeeping requirements for engines which are necessary to document exemption status. However, in the future, the commission may pursue requirements for these engines to prevent emissions increases if they are operated in peak shaving mode, or to address their emissions if additional reductions are determined to be necessary to reach attainment with the ozone NAAQS.

As noted earlier in this preamble, the commission added a new §117.475(c)(3), which provides low annual capacity factor units with an alternative emission specifications. The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units 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.

MONITORING REQUIREMENTS

Two individuals suggested that continuous monitoring of emissions be required. One of the individuals suggested that the results be published in the newspapers. Another individual suggested that CEMS/PEMS data be transmitted directly to TNRCC regional offices.

The adopted rules include requirements for continuous monitoring systems (CEMS or PEMS). Emissions data is submitted to the commission, and therefore is a public record available to the public for review. Therefore, the commission does not believe it is necessary to require the regulated community to publish emissions data in the newspaper. It is impractical to require that CEMS/PEMS data be transmitted directly to TNRCC regional offices because the commission has the authority to request monitoring information at any time, and therefore simply accumulating duplicate data in the regional office would serve no useful purpose.

Kinder Morgan and TGP commented on periodic testing for emergency generators and other low capacity factor units in §117.214(a)(1) and §117.213(g). Kinder Morgan and TGP suggested the inclusion of an exemption that would only require testing of low annual capacity factor units in cases of

installing controls, after performing major maintenance, permit renewals, or in cases where the operator or agency believes the emissions may have changed. Kinder Morgan and TGP's suggested language would not require periodic emission testing for engines run no more than ten hours per month. Enron suggested that low annual capacity factor engines not be required to conduct periodic emission testing, except after installation of controls, major repair work, or when the owner/operator believes that emissions may have changed. Pasadena/Donohue likewise suggested that low annual capacity factor engines not be required to conduct periodic emission testing, and stated that testing would result in more emissions than actual operation of its auxiliary engine during power outages.

The commission has corrected a reference in §117.214(a)(1) to §117.213(g) and has revised §117.213(g) by adding a new paragraph (2) to specify an alternative to periodic testing for engines which use a chemical reagent for reduction of NO_x. Since these engines are required under §117.213(c)(1)(E) to be equipped with NO_x CEMS or PEMS, there is no need for these engines to conduct periodic testing. Therefore, the commission has subdivided §117.213(g) into requirements for engines with and without CEMS/PEMS, and has added a new paragraph (2) which specifies that engines which use a chemical reagent for reduction of NO_x shall comply with the with NO_x CEMS or PEMS requirements rather than conduct periodic testing.

Regarding low annual capacity factor engines, the commission notes that §117.213(g) applies to engines which are subject to an emission specification. Because the commission has added a new paragraph (10) to §117.203(a) which exempts diesel-fired engines, these engines will not be required to conduct testing under §117.213(g). However, gas-fired emergency generators are

subject to the ESADs. The commission has revised §117.213(g) by adding a new paragraph (1)(C) for which specifies that gas-fired emergency generators are not required to conduct periodic testing under the renumbered §117.213(g)(1)(B).

The commission has revised §117.208(d) to exclude sources subject to §117.206(c) and has concurrently added a quarterly engine testing requirement as new §117.214(b)(2). Because quarterly emission testing for engines that run no more than ten hours per month could result in these engines operating when they otherwise would be idle, thereby increasing emissions, the commission has included language which states that 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.

BP, Phillips 66, TCC, and TxOGA suggested that the CEMS/PEMS requirements should be limited to units being controlled by SCR, rather than basing the CEMS/PEMS requirements on heat input. As an alternative to CEMS/PEMS monitoring, Dynegy suggested that monitoring be performed quarterly with a portable gas analyzer (or equivalent methodology) and whenever maintenance activities may affect the NO_x emissions. TCC stated that the heat input threshold for CEMS/PEMS requirements should be 250 MMBtu/hr for boilers and 200 MMBtu/hr for process heaters, rather than 100 MMBtu/hr for these sources. TGP stated that the CEMS/PEMS requirements for IC engines is overly burdensome and that even if an IC engine is converted to electric, the current language in §117.213(c)(2)(A) mandates a CEMS or PEMS.

NO_x monitors will be key to a successful point source emission reduction program and is critical to achieving real reductions in NO_x emissions which are necessary to attain the ozone NAAQS. Without CEMS/PEMS, estimating NO_x emissions is subjective. NO_x is a product of a dynamic reaction in a flame, and can easily vary tenfold in a brief time. Units controlled by combustion modification are not immune to variability in NO_x emissions. By basing the monitoring requirements on size of equipment (heat input), the commission does not discriminate between control technologies while ensuring that the greater portion of the point source NO_x in HGA will be reduced to the required specifications. The monitoring suggested by Dynegy may be more appropriate for sources not required to install NO_x monitors under the adopted rule. The language in 117.213(c)(2) is a list of NO_x sources not required to install a CEMS or PEMS under §117.213. An electric motor is not listed because it is not a NO_x source.

TCC stated that flexible monitoring and recordkeeping methods are appropriate for SCR. TCC stated that actual ammonia levels should be determined based on a stoichiometric material balance and actual material use, rather than through the use of monitors. TCC stated that additional continuous monitoring devices increase labor, material, and maintenance costs, and do not reduce emissions in and of themselves.

The CEMS/PEMS requirements are for the monitoring of NO_x, CO, and either O_2 or CO_2. Ammonia slip emissions do not rise to a level of concern that would justify requiring continuous monitors for ammonia.

Pavilion requested confirmation that PEMS are allowed as an alternative to CEMS.

The commission confirms that PEMS are specifically allowed as an alternative to CEMS under §117.213(c)(1).

Pavilion stated that the commission should adopt some form of the TNRCC PEMS Draft Protocol as part of the rule in order to clarify the PEMS requirements and agency policies to the regulated community and the TNRCC's field operations and enforcement groups.

The TNRCC PEMS Draft Protocol is available to the regulated community as well as enforcement personnel in order to clarify the PEMS requirements for both regulations and for NSR permits. Therefore, the commission does not believe that it is necessary to adopt this guidance as a rule.

Pavilion stated that all units should be required to implement advanced process monitoring and control schemes as part of standard operating procedures of control devices. Pavilion stated that advanced process monitoring can detect if a unit and/or add-on control device is malfunctioning, thereby reducing pollution on a consistent basis, minimizing reagent usage and reagent slip, and decreasing the operating costs necessary to comply with the rule.

Monitoring to determine the instantaneous NO_x level is useful in allowing tight process control and rapid corrective actions to reduce NO_x emissions. The adopted rules include appropriate emission monitoring requirements.

Pasadena/Donohue commented on the CEMS requirements of §117.213(e)(3)(A) and stated that the requirement to analyze separately the exhaust stream of each unit sharing a CEMS should be revised to provide an exception for units in the mass cap and trade program since the purpose is to monitor and document actual NO_x emissions for deduction from allowance accounts on an annual basis. Pasadena/Donohue stated that similar language should be added to the PEMS requirements of §117.213(f).

Under §117.213(e)(3), several units, each venting to a single stack, can share a single CEMS, thereby reducing the monitoring costs. The requirement to analyze separately the exhaust stream does not apply to the case of several units venting to a common stack, which is not the case addressed by subsection (e)(3). The cap and trade program is concerned only with total emissions to the atmosphere, so monitoring combined emissions in a single stack is at least as effective an enforcement approach as monitoring separate streams. It is also simpler and more cost effective than monitoring separate streams. In contrast to a CEMS, which measures the gaseous concentration of a pollutant, a PEMS predicts pollutant emissions and does not directly measure the gaseous concentration. Some PEMS rely on physical principles which employs analytical methods to describe the dynamics of the process. These methods are derived from the physical equations or the laws of nature that govern the system. This category of models is typically expressed in nonlinear partial differential equations that are solved via numerical analysis techniques, as these equations are often too complicated to be solved via standard analytical methods. Other PEMS rely mainly on computer software which, with the use of high quality historical data, interpolates and/or extrapolates over a wider range of operating conditions, or

learns the dynamics of the process by developing statistical multi-variable mathematical functions that mask the dynamics of the process. Since a PEMS is necessarily dependent on the process, it is not appropriate to extend the CEMS flexibility of §117.213(e)(3) to PEMS.

Sierra-Houston commented on §§117.114(c)(2)(B), 117.214(c)(2)(B), and 117.479(e)(7)(B) and noted that retesting must occur within 60 days after any modification which could reasonably be expected to increase the NO_x emission rate. Sierra-Houston objected to the retesting being optional after any modification which could reasonably be expected to decrease the NO_x emission rate.

The commission disagrees with the commenter. While it is important for retesting to occur if the emission rate could have increased to ensure that the emission reduction requirements are still being met, it is not important for retesting to occur if the emission rate decreased. The owner or operator may choose to conduct retesting after any modification which could decrease the NO_x emission rate since the emission reduction requirements logically would continue to be met after an emissions decrease.

The EPA commented on §117.478(b)(5), concerning the requirement for checking the proper operation of an IC engine after maintenance that might be reasonably expected to increase emissions. The EPA stated that the term “as soon as practicable” is vague and makes enforcement for violations of proper operating procedures very difficult and perhaps impossible. The EPA suggested that a specific time limit such as two weeks could be set for when to check the operation of the engine after maintenance.

The commission agrees and has revised §117.478(b)(5) accordingly.

Union Carbide stated that §117.520(c)(2)(D) has a conflict with §117.520(c)(2)(E) and §117.211 concerning when the first relative accuracy test audit (RATA) is due. Union Carbide requested clarification of when the initial RATA and demonstration of compliance have to be completed and when the initial demonstration of compliance report has to be submitted.

The commission has revised §117.510(c)(2) and §117.520(c)(2) to specify that the applicable CEMS or PEMS performance evaluation and quality assurance procedures must be submitted within 60 days after startup of a unit following installation of emission controls, or by March 31, 2005, whichever comes first. An initial demonstration of compliance report is not required. Also, as described earlier in this preamble, the commission revised §117.116 and §117.216 to exclude sources in HGA since the testing and monitoring of §117.114 and §117.214, in conjunction with the requirements of the mass emissions cap and trade program, will be sufficient to determine compliance.

COMPLIANCE SCHEDULE

ExxonMobil stated that the commission has not provided legal justification for the proposed December 31, 2004 compliance date. ExxonMobil asserted that this date exceeds federal requirements because it believes the commission has the discretion, supported by federal law, EPA policy, and precedent, to specify a 2007 compliance date.

The commission has modified the original proposal to call for the final phase of reductions after the mid-course review and in the 2006 - 2007 time frame. The commission will review the option of an attainment date extension, if that becomes necessary, when appropriate. The measures adopted here are being implemented as expeditiously as practicable. The commission believes that the measures adopted here will be sufficient to demonstrate attainment with the one-hour ozone standard along the time line indicated by federal guidance.

BCCA asserted that the NO_x SIP point source rule proposal preamble lacks valid, current, and adequate scientific and technical support for the proposed implementation timing, and that there is no discussion or consideration of implementation timing issues.

The implementation schedule and the technical feasibility have been analyzed separately in this adoption preamble in order to show as clearly as possible the reasoning the commission used in adopting the ESADs and in developing the compliance schedule. The commission has tried to use the term technical feasibility in a sense that does not depend on the schedule. What is technically feasible is a function of the state of current engineering practice. The appropriate schedule for applying the technically feasible controls is a function of the practicability (or difficulty) of a certain rate of application. In other words, control measures which are technically feasible remain so, but there needs to be a feasible schedule to apply them. Responses to comments concerning the technical feasibility are discussed in detail earlier in this preamble under the heading of *TECHNICAL FEASIBILITY* for the various source categories. Implementation timing issues are addressed in the remaining portion of this section of the preamble.

Baytown, Baytown COC, BCCA, Chevron, Crown, Diamond-Koch, Dynegy, Entergy, Enterprise, Equistar, ExxonMobil, GPA, Lyondell-Citgo, Lyondell, Kinder Morgan, NASA, PECO, Phillips 66, REI, Rhodia, TCC, Texas Eastern, TGC, TGP, TPIEC, TxOGA, Union Carbide, Valero, and five individuals commented that an adequate amount of time should be given for compliance with the new requirements, while Sierra-Houston supported the proposed three-year compliance schedule for electric utility EGFs. BP stated that its plants could comply with the proposed compliance schedule but suggested that half the emission reductions be required by December 31, 2003, with the remainder by December 31, 2004. BP, BCCA, and Diamond-Koch stated that a longer compliance schedule would allow phase-in of controls with normal planned outages. Chevron suggested that half the emission reductions be required by June 2003, with the remainder by December 31, 2004, with the availability of the executive director to grant a six to 12-month extension if necessary. Baytown and Baytown COC suggested that the compliance date should be May 2007. Dynegy, Entergy, Equistar, Goodyear, Lyondell, PECO, Texas Eastern, TPIEC, and Valero suggested a five-year implementation schedule, beginning December 31, 2002 and ending December 31, 2007. Lyondell-Citgo, Phillips 66, and TxOGA stated that the compliance date should be no earlier than 2007. NASA stated that a longer compliance schedule should be included for federal facilities due to budgetary and timing constraints. Rhodia suggested that the phased compliance schedule be replaced with a compliance date of 2005 for all emission reductions. TCC stated that the annual reduction targets be applied to HGA as a whole, rather than to specific, individual sources, and that the first annual one-third reduction target (December 31, 2002) should be limited to major electric utilities, with petrochemical plants specifically excluded. Kinder Morgan, TGC, and TGP stated that the initial compliance date should be December 31, 2003 rather than December 31, 2002. Union Carbide suggested that the annual reduction targets be one-third

plus/minus some percentage. Enterprise suggested that 50% - 75% of the emission reductions be required by December 31, 2005, with implementation of a mid-course correction by that time. GPA suggested that 10% of the emission reductions be required each year from 2003 through 2005, a 50% emission reduction in 2006, and the remainder in 2007. ExxonMobil stated that the commission has not provided adequate scientific and technical analyses or justification for the proposed December 31, 2004 compliance date and suggested a March 31, 2007 compliance date. An individual suggested that units fired on liquid fuel or nitrogen-laden fuel should be given an additional three years for compliance. BCCA, ExxonMobil, and TCC suggested that the compliance schedule be more consistent with normal process unit turnaround cycles and the availability of manpower and material resources, and stated that this would dramatically improve the cost effectiveness of proposed rule while minimizing the potential for product disruption, supply shortages, and consumer price increases.

After careful consideration of the commenters' concerns and suggestions in conjunction with the 42 USC, §7502(a)(2), requirement to achieve attainment as expeditiously as practicable, the commission has revised the compliance schedule as follows. For sources other than investor-owned electric utilities, the commission is adopting a staged six-year implementation schedule for compliance with the new HGA ESADs. First, 44% of the total reductions required to comply with the ESADs are required by March 31, 2004. The next 45% of the reductions are required by March 31, 2005. The final reductions are required by March 31, 2007. This revised schedule will provide an additional year and a quarter before the first reductions are required, yet still result in 89% of the emission reductions before the critical 2005 ozone season. This schedule will result in emission reductions as expeditiously as practicable, yet will allow the more difficult to control or

more expensive emission reduction projects six years to achieve the emission reductions. The commission believes that this revised compliance schedule will allow the emission reduction projects to be more consistent with normal process unit turnaround cycles, allow additional incorporation of emerging technologies, reduce labor and material availability concerns, and concurrently reduce costs, thereby improving the cost effectiveness while minimizing the potential for product disruption, supply shortages, and consumer price increases. The commission also believes that this revised compliance schedule facilitates a determination at the mid-course review by May 1, 2004 to ensure that the final 11% of the reductions are necessary for attainment of the ozone standard. The adopted compliance schedule for sources other than investor-owned electric utilities allows the maximum feasible time under the federal requirement to attain the ozone standard in HGA by 2007.

For investor-owned electric utilities, the commission is adopting a staged six-year implementation schedule for compliance with the new HGA ESADs. First, 46% of the total reductions required to comply with the ESADs are required by March 31, 2003. The next 46% of the reductions are required by March 31, 2004. The final reductions are required by March 31, 2007. The commission believes that this compliance schedule is appropriate for investor-owned electric utilities since emission reduction projects are already underway to implement the majority of the emission reductions necessary to meet the ESADs for investor-owned electric utilities. The adopted compliance schedule for investor-owned electric utilities allows the maximum feasible time under the federal requirement to attain the ozone standard in HGA by 2007.

TCC expressed concern that the proposed compliance schedule will cause financial, planning, and competitive difficulties for smaller, but still major, sources. As an example, TCC stated that a plant with a large boiler and either no, or only a small number of, smaller sources will be required to control the boiler by December 31, 2002 to meet the first one-third rate-of-progress requirement. TCC stated that the requirement to make such a large capital outlay early on in the program relative to larger sources will be very difficult to fund, implement, and schedule and may result in negative effects on the competitiveness of the source.

A major source with a single unit, or a small number of units, does not necessarily have to install controls to achieve all of the target emission reductions by the first compliance date. 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 a combination of the two approaches. The owner or operator might choose to make Tier I combustion modifications sufficient to achieve the initial rate-of-progress reductions in order to delay the capital expenditure for Tier II controls until a later date. Alternatively, the owner or operator might choose to implement the emission reduction projects ahead of schedule in order to be able to sell the surplus allowances. There is an infinite number of permutations. Ultimately, each owner or operator will make a business decision believed to represent the best choice for each unique situation. 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.

BCCA stated that for all of the HGA point source categories, there is no experience with retrofit NO_x control technology applications that have been demonstrated to perform at the levels proposed, and that time for technology development, testing, and prototyping before commercialization will be required to overcome the many technical limitations that are now being identified as the result of detailed engineering and design reviews. BP, Diamond-Koch, and TCC stated that a longer compliance schedule could allow capture of benefits from emerging technologies as well as ease concerns about availability of labor and materials. BCCA stated that the commission has not allowed for sufficient time for the necessary technology developments with the proposed December 31, 2004 compliance date.

The commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of the adopted 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 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 earlier in this preamble.

NO_x controls have rapidly improved in capability recently. It is also clear from the numerous technical innovations under development today that NO_x control technology is continuing to improve rapidly. The commission agrees with the commenters that a longer compliance schedule

could allow capture of benefits from emerging technologies as well as ease concerns about availability of labor and materials. As described earlier in this section of the preamble, the commission extended the compliance schedule for sources other than investor-owned electric utilities. This will allow additional incorporation of emerging technologies, reduce labor and material availability concerns, and concurrently reduce costs.

BCCA and TCC stated that the December 31, 2004 compliance date does not recognize the magnitude of manpower and material resources required to implement the proposed rule, does not allow for the practical implementation of controls, and is not physically possible. BCCA and TCC stated that the proposed implementation timing is too short and will cause significant manpower, material, and equipment shortages nationwide, will result in supply disruptions of fuels, petrochemical products and intermediates, and will unnecessarily increase the cost of products for consumers. BCCA stated that facility operators will need 12 - 18 months from the December 2000 rule adoption to scope and design equipment, secure permits, perform detailed engineering, secure funding, and begin the installation of controls. BCCA stated that consequently it will not be until 2002 that many companies will be in a position to begin control installation, leaving only three years for some 180 companies to begin retrofitting over 2,500 individual units. BCCA commented that these companies will be competing for limited resources to engineer, design, permit, construct, and operate some 1,900 boilers, heaters, turbines, and engines, newly modified with SCR technology.

BCCA stated that a study completed by a consultant determined that demand for construction labor between 2002 - 2004 will consume 175% the available supply in the entire upper Gulf Coast (HGA to

Baton Rouge, LA) area as forecasted by the 2000 *Houston Business Roundtable - Gulf Coast Workforce Projection Survey*; that demand for front-end design engineering human resources between 2002 - 2004 will consume 145% of the available nationwide supply as forecasted by the 1999 *Joint Industry Program Engineering, Procurement and Construction Survey*; and that demand for detailed engineering design resources between 2002 - 2004 will consume 128% of the available nationwide supply as forecasted by the 1999 *Joint Industry Program Engineering, Procurement and Construction Survey*.

BCCA further stated that the consultant's study determined that highly specialized labor resources, such as furnace engineering evaluation specialists and flue-gas computational fluid dynamics modelers are expected to be in short in supply and a critical path limitation to timely completion of engineering design activities; and that demand for burner testing facilities to demonstrate, certify, and guarantee NO_x emission performance of new burners will exceed current worldwide burner testing capability by 200%. BCCA stated that this will be another critical path limitation to timely delivery of new burners to meet the proposed December 31, 2004 compliance deadline. BCCA also stated that demand for SCR catalyst for HGA and the 22 State OTAG NO_x SIP Call between 2002 - 2004 will exceed available worldwide production capability by 500%. ExxonMobil expressed similar concerns about the results of the consultant's study.

The commenters have overstated the number of SCRs that will be installed. Point source NO_x reductions in the range of 90% requires 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 a 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 adopted emission specifications and further details of the technical feasibility of the emission specifications can be found elsewhere in this preamble. 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 that the Chapter 117 cost note contemplated. Although the number of SCRs is expected to be unprecedented, the ultimate number installed is virtually 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 adopted rules give 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.

Kinder Morgan, TGC, and TGP stated that the commission did not address issues with respect to FERC and the National Environmental Policy Act (NEPA) (18 CFR Part 380). Kinder Morgan, TGC, and TGP stated that interstate natural gas pipeline systems, including compressor stations, used in the interstate transportation of natural gas are governed by the Natural Gas Act, 15 USC, §§717 et seq. (NGA) and regulated by the FERC, which typically acts as the lead agency in the implementation of the regulations and guidelines of NEPA. Kinder Morgan, TGC, and TGP stated that the NGA requires that interstate pipeline system compression capacity be approved by the FERC. Kinder Morgan, TGC, and TGP stated that the installation of new compression requires an applicant to file with the FERC an Application for a Certificate of Public Convenience and Necessity (Application) under the NGA, §7(c). Kinder Morgan, TGC, and TGP stated that it is unlikely that the electric motor driven compression will exactly match the existing FERC certificated IC compression capacity at any given compressor station and that as a result, it will be required to apply for and obtain FERC approval consisting of a Certificate of Public Convenience and Necessity (Certificate) prior to the construction of any replacement facilities. Kinder Morgan, TGC, and TGP stated that the application preparation, review, and approval process typically takes at least one year. Kinder Morgan, TGC, and TGP stated that additionally, the FERC is required to evaluate cumulative impacts potentially resulting from a proposed

project, and that such cumulative impacts include the displacement of emissions from the end user (e.g., Kinder Morgan, TGC, or TGP) to the energy source (the EGF), new electric transmission corridors, areas associated with the disposal of the facilities being replaced, and installation of electric transmission lines to provide electrical power for the newly constructed electric driven compression. Kinder Morgan, TGC, and TGP stated that due to the level of effort involved in the preparation of an application and the FERC review timeline, it is highly unlikely that interstate natural gas pipeline companies would receive the appropriate FERC approvals to authorize construction prior to January 1, 2002. Kinder Morgan, TGC, and TGP stated that as a result, additional time is needed to meet the mandatory requirements for electric conversion.

As noted earlier in this preamble, the commission re-examined the issues of technical feasibility of the proposed ESADs for stationary IC engines and adjusted these ESADs such that the level of control is technically feasible without wholesale replacement of engines. Nevertheless, an option for compliance with the ESADs is still the replacement of IC engines with electric drive motors, as in fact has already occurred at some sites due to the cost savings associated with reduced labor costs for maintenance of the IC engines. As described earlier in this section of the preamble, the commission extended the compliance schedule for sources other than investor-owned electric utilities in order to allow implementation of emission reduction projects as efficiently as possible and reduce the unscheduled downtime and any associated costs. This longer compliance schedule will also allow the necessary time for owners and operators to address FERC and NEPA issues associated with the replacement of IC engines with electric drive motors. In addition, there is no major federal action associated with these rules that triggers compliance with NEPA.

BCCA stated that if electric drive motors replace engines, the sheer number of replacements will strain the availability of motors, switch gear, and other components and that power will have to be supplied to 36 sites at an average of three miles per site. BCCA stated that installing NSCR on rich-burn engines will lead to the same concerns over catalyst availability and competition for welders and general construction workers as for other source categories. BCCA and TGC also stated that LEC technology for lean-burn engines is highly specialized and requires almost case-by-case engineering to optimize the technology as well as specialized expertise to install the hardware. BCCA stated that this specialized engineering and installation expertise is in short supply; the specialized hardware is supplied primarily by after-market vendors since many of the original equipment manufacturers are no longer in business or no longer support some of the engine models used in HGA; and after-market vendors will have difficulty supplying parts for large-scale retrofit activity over a short time frame.

The assessment of a leading vendor of electric drive motors and the related equipment for compressor stations is that there is adequate manufacturing capacity to respond to the increased demand within the proposed time frame. The expected widespread conversion to electric motors for the larger sites and the many rich-burn IC engines which already have NSCRs and air-fuel ratio controllers as a result of NO_x RACT limits the number of NSCR and LEC retrofits. There is a significant infrastructure in place in HGA for supplying emission controls for gas-fired engines which has little overlap with other specialized service providers for other source categories. A leading vendor of NSCR catalyst indicates that manufacturing capacity will not be an issue. NSCR catalyst is used by the automobile manufacturing industry and the stationary source market is very small by proportion. Nonetheless, phasing the controls in with a six-year

compliance schedule would have a significant mitigating effect on any supply issues which may arise, particularly for SCR and LECs, which will be competing with the SIP call sources.

BASF, BCCA, Dynegy, Equistar, Lyondell-Citgo, Lyondell, Phillips 66, TCC, TIP, TPIEC, TxOGA, Union Carbide, and Valero commented that the compliance date for installation of totalizing fuel flow meters and CEMS/PEMS should be changed from December 31, 2001. BASF suggested that the deadline be consistent with the SIP compliance dates of December 31, 2002 - 2004. BCCA, Equistar, Lyondell, Phillips 66, TCC, TIP, TPIEC, TxOGA, and Valero suggested that the deadline be changed to 2007. BASF stated that unit outages may be required for fuel flow meter installation and that CEMS/PEMS certification may be difficult to complete by December 31, 2001 due to the limited number of testing companies and their workloads. BASF, Dynegy, Lyondell-Citgo, Phillips 66, TPIEC, TxOGA, Union Carbide commented that CEMS/PEMS selection depends on the type of controls that are installed and therefore, that monitoring should not be required prior to the installation of the required controls. BASF, Dynegy, TPIEC, and Valero suggested that stack testing be used prior to CEMS/PEMS installation to verify emission estimates.

The rules have been changed in response to this comment. The commission proposed a December 31, 2001 compliance date for installation of emissions monitors and fuel meters in order to improve the consistency of the value of a NO_x allowance at the start of the trading program and to improve the inputs used in the commission's air quality planning tools. However, the proposed schedule did not take into account the practicalities identified by the commenters. Both PEMS and CEMS vendors indicated that the number of monitors required in one year would strain their

abilities to provide the equipment. The owners identified clear benefits of installing the monitors in conjunction with the control equipment. If a CEMS is installed before the flue gas controls are fully constructed, the CEMS may need to be uninstalled during construction and possibly relocated after NO_x controls. A PEMS will need to be retrained after the installation of control equipment. Phasing in CEMS/PEMS with the emission control equipment is a more rational and cost-effective approach. Therefore, the commission has modified §117.520(c) to require that the monitors will be phased over a four-year period, at the earlier of installing emission controls or March 31, 2005. This phase-in will achieve the end result benefits of specified emissions reduction by 2005. Because the first reduction period has been extended to 2004, the greater uncertainty about NO_x emissions in the first two years of the program (compared to monitors in place by 2002) will be of less consequence.

The EPA commented on the proposed revision to §117.510(b)(2)(B), which would modify the compliance schedule for utility boilers in DFW by allowing utility boilers retired and decommissioned before May 1, 2005 to be excluded from the calculation of the emission reductions to be made by May 1, 2003. The EPA stated that the commission should include a justification of how this approach will implement reductions as expeditiously as practicable, or the rule would not be approvable for the DFW SIP.

The revised schedule will facilitate an orderly installation of NO_x controls by allowing soon-to-be-retired utility boilers to remain online during the construction and startup of emission reduction projects in DFW. This will ensure the continued reliability of the electric power distribution grid

during the transition period, which is necessary in order for the implementation of emission reductions as expeditiously as practicable. The emission reductions from the soon-to-be-retired utility boilers will occur before the critical 2005 ozone season, and therefore will contribute to DFW's attainment of the ozone NAAQS.

COST

BCCA, Entergy, Equistar, ExxonMobil, and Lyondell asserted that most of the emission limitations were developed with a less than complete analysis of the economic feasibility of the resulting controls, or an analysis of the possible economic disbenefit of the proposed controls. BCCA and ExxonMobil stated that the commission appears to have first established an arbitrary NO_x reduction target for point sources (i.e., 90%) and, through an iterative process, back-calculated the emission limits necessary to achieve the desired target. BCCA and ExxonMobil stated that this is "an arbitrary approach to establishing air pollution standards, and circumvents the intent established in the Texas Clean Air Act to establish standards based on a technological and economical review of available control measures."

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 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 described in detail earlier in this preamble, the ESADs are not arbitrary and were developed with sufficient analysis to justify the limits and the technical feasibility of the resulting controls. The proposed rules contained a detailed, but admittedly approximate, estimate of the costs of the controls based on information available to the commission. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the commission must seek to accomplish the goal of protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required

standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

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 rule proposal preamble, 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 ESADs. This demonstrates that the commission has sought to accomplish its duty.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

TCAA, §382.012, also requires the commission to develop a general comprehensive plan for the proper control of the state's air. The control of the air quality includes various measures such as emission limits and controls on point sources through permit and rules, as well as regulation of certain on-road and non-road sources, and, for compliance with the NAAQS, the control plan meets the FCAA requirement to develop a SIP. As discussed earlier in this preamble, this rule adoption is one element of the control strategy for the HGA SIP and it is the adoption and

implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Specifically, this rule adoption comprises a large portion of the control strategy necessary to achieve attainment. Therefore, the requirement to properly control the state's air must also meet the comprehensive plan requirements, implemented through the SIP. Unless the plan meets the SIP requirements in the FCAA, which includes meeting NAAQS, the commission is not in compliance with the TCAA. Therefore, the plan as a whole must be examined to ensure that all legal requirements are met. The Texas Code Construction Act, Texas Government Code, §311.021, requires that it is presumed that the entire statute is intended to be effective. Thus, a reading of TCAA, §382.011 and §382.012, leads to the conclusion that the adopted rules meet the requirements of both the TCAA and FCAA.

BCCA stated that three key options for NO_x control are available: application of retrofit control technology on existing equipment; replacement or consolidation of existing equipment; and shutdown of existing equipment. BCCA asserted that there is no evidence in the proposed rule that the commission weighed and analyzed the costs of the potential control options that operators will be required to use to reach NO_x reduction targets. BCCA stated further that there will be instances where the direct application of retrofit technology will not meet the desired NO_x emission targets and where replacement and consolidation of existing equipment will not be economically feasible. BCCA stated that in those instances, the shutdown of equipment must be considered as the last remaining viable measure to meet the NO_x reduction. BCCA stated that capacity reductions, product line shutdowns, and some plant shutdowns will occur as a result of the proposed rule and asserted that the commission has not

considered the economic impacts of the anticipated capacity reductions and shutdowns that could occur as a result of the proposed emission limitations.

The comments received did not identify specific plants or equipment lines that would be rendered uneconomical as a result of the cost, and therefore there is no indication that there will be widespread shutdowns. In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates that, even with the use of the mass emissions cap and trade program, that choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment that the rules are economically infeasible. ExxonMobil said that cost analyses would have to be done and some production lines would shut down; if this were to occur on a limited scale it could be viewed as the most rational solution to obtaining the goals of a cleaner environment and maintaining an efficient marketplace. 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 rule proposal preamble, 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 ESADs. This demonstrates that the commission has sought to accomplish its duty.

BCCA stated that the estimated total capital cost for affected HGA sources of approximately $2.7 billion is low by more than a factor of two, and suggested that the commission's cost estimates were based on new, grass roots facilities that have been specifically designed for low-NO_x performance technology, as opposed to cost estimates for the retrofitting of existing equipment. CAP, Clear Lake COC, Crown, Dow, Dynegy, ExxonMobil, Houston MPO, Lyondell-Citgo, Phillips 66, REI, and Texas City Mayor Carlos Garza expressed similar concerns about the cost of control technology.

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. BCCA may be correct that the

cost in the preamble 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, BCCA's 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 pre-heat ammonia injection air, thereby lowering the power requirements of the ammonia injection system.

The engine costs were based on specific costs of electric motor conversion of a gas-fired compressor station in Houston, so they also were not based on grass roots installations costs.

The cost estimates in other categories which were based on SCR control used the same cost model

as the heaters and boilers, which as discussed earlier, used actual SCR retrofit data.

The CEMS cost estimates were based on the EPA cost model, *U.S. EPA's Continuous Emission Monitoring System Cost Model, Version 3.0*, a flexible model which details more than 50 individual cost components associated with the purchase and installation of a CEMS. CEMS vendors corroborate costs similar to the EPA model. The commission notes that the number of CEMS/PEMS would be closer to 700 than the 300 in the rule proposal preamble because many of the boilers and heaters in the 40 - 100 MMBtu/hr range are expected to install SCR, which necessitates a NO_X monitor. Using the EPA cost model, the commission estimates the cost of 300 additional CEMS to be approximately $72 million.

BCCA, Entergy, and REI stated that the proposed emission specifications for utility boilers are economically infeasible in wide-scale retrofit applications. BCCA stated that although the proposed rate for utility boilers can be achieved in limited applications, the ESAD is economically unreasonable for many gas-fired boilers.

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. These projects are likely to make older, far less efficient boilers economically worthless anyway by 2005. In addition, the commission is not required to set ESADs which are economically reasonable. Rather, as discussed earlier in this preamble, the commission must seek to accomplish the

requirement to control the quality of the state's air by practical and economically feasible methods. The commission has met those requirements in adopting these rules.

There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the commission must seek to accomplish the goal of protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically

infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

Entergy stated that the commission's cost estimate for gas-fired utility boilers underestimate retrofit costs for the region because the units in the NESCAUM report represented an 85% NO_x reduction (i.e., from 0.20 to 0.030 lb/MMBtu), and asserted that the commission did not take into account the significant incremental expense of controlling by 95% (to 0.010 lb/MMBtu). Entergy stated that as a result, the limits for gas-fired utility boilers are financially inequitable. REI similarly stated that the commission underestimated the costs for utility boilers.

The commission disagrees with the commenter. The actual performance data referenced in the first response in the *TECHNICAL FEASIBILITY - UTILITY BOILERS* section clearly indicates that the selection of 85% reduction in the NESCAUM cost evaluation spreadsheet was not meant to illustrate the technical limits of SCR. The cost differential between 85% and 90% reduction with SCR on a gas-fired boiler is likely to be small; 90% reduction is often the most cost-effective reduction. Entergy doesn't need to make a 95% reduction, because they are operating at 0.15 and

0.16 on their 30-day compliance average under the NO_x RACT rule. In addition, combustion modifications appear to be capable of achieving significantly lower than 0.10 lb/MMBtu on many gas-fired utility boilers today. The flexibility of combining additional combustion and flue gas cleanup controls on these boilers will result in costs similar to those estimated in the cost note. The cost note for REI, at $610 million for a 93% reduction, is similar to the $480 million cost that REI has estimated for their 88% reduction plan. There is no requirement that the commission set limits that are financially equitable among types of equipment.

BCCA and REI stated that typical capacity factors for auxiliary boilers are less than 10%, and therefore the costs for SCR are not economically reasonable given the limited NO_x reduction potential and low service factor.

The commission agrees that SCR is not an appropriate choice for auxiliary boilers because they infrequently operate at high loads. The infrequent operation at high loads means that the cost effectiveness will be extremely poor, regardless of whether SCR is technically infeasible in this application. As noted earlier in the *TECHNICAL FEASIBILITY - AUXILIARY BOILERS* section, the commission has added an alternative emission specification as new §117.106(c)(4) for auxiliary boilers, utility boilers, and stationary gas turbines based on Tier I controls. The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for these units 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. This adopted standard is one which some of the auxiliary boilers are currently meeting with combustion modifications, and which should be technically feasible for the

others with combustion modifications. This change would significantly lower the cost of control if the utility chooses to control these units rather than make up the reductions elsewhere under the cap and trade program. As discussed earlier in this preamble, the commission must seek to accomplish the requirement to control the quality of the state's air by practical and economically feasible methods. The commission has met those requirements in adopting these rules. There is no requirement that the commission must determine that the costs be economically reasonable.

BCCA stated that the commission's cost estimate of $2.1 million dollars per unit ($403 million total for HGA) underestimate the gas turbine retrofit costs for the region. REI similarly stated that the commission underestimated the costs for gas turbines. BCCA asserted that the EPA reference guide used does not adequately represent retrofit costs, but instead is more representative of the cost of new, grassroots SCR installations as noted in the reference document itself. Based on the best engineering data available from BCCA member companies, BCCA estimated that the capital cost for approximately 180 gas-fired turbines in HGA to be retrofitted with SCR controls to achieve the desired NO_x reduction target will be in the $0.8 - 1.2 billion range, depending on the turbine design, power output and use. BCCA, Kinder Morgan, Solar Turbines, and TCC stated that the proposed emission specification imposes an excessively high cost on small gas turbines (less than 10 - 20 MW).

Total annualized costs for turbines were estimated from cost tables 6-6, 6-9, 6-10, and 6-12 of EPA's ACT document, *Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines*, (EPA-453/R-93-007). The turbine cost estimate may well be low, but many of them are among the largest sources of NO_x in the area. In fact, of all point source categories in HGA,

the gas turbine category has NO_x emissions second only to utility boilers. The commission must consider that reductions from these largest sources are a necessary component of the plan, and it may undermine the economic feasibility to not include this group merely based on underestimated costs for a few categories. Regarding the cost for small turbines, as noted earlier in this preamble, the commission has revised the ESAD in §117.106(c)(3) and §117.206(c)(10) for existing stationary gas turbines rated at less than 1.0 MW to 0.15 lb NO_x per MMBtu. This will mitigate the costs somewhat for these smaller turbines. In addition, the market-based control program is expected to minimize the costs necessary to achieve the required reductions. Specifically, 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 rule proposal preamble, 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 ESADs.

There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the commission must seek to accomplish the goal of

protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits,

replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

Enterprise stated that a 90% reduction from the estimated 60 small gas turbines (i.e., up to ten MW) represent only 2,254 tpy of NO_x reductions at a disproportionately higher cost than for the estimated 180 large gas turbines (i.e., ten MW or greater). BCCA, PECO, REI, and Solar Turbines stated that the proposed emission specifications for gas turbines are economically infeasible in wide-scale retrofit applications. BCCA noted that gas turbines can be found in utility plants, industrial plants, and remote pipeline transmission sites, and stated that each location, and in many cases each machine, has its own unique design and operating conditions that need to be considered when determining the cost of a particular NO_x reduction technology.

The commission agrees that in many cases each gas turbine has its own unique design and operating conditions that need to be considered in evaluating feasibility and cost. As discussed elsewhere in this preamble, gas turbine retrofit costs are likely to be higher than estimated in the rule proposal. The costs for the smallest gas turbines (less than 1.0 MW) have been reduced because the adopted ESAD is based on Tier II controls rather than Tier III controls, and the total reduction required for this category of smallest gas turbines is 0.2 tpd less than proposed.

In addition, the market-based control program is expected to minimize the costs necessary to achieve the required reductions. Specifically, 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 rule proposal preamble, 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 ESADs. Therefore, the commission disagrees that the ESAD for gas turbines are economically infeasible.

There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the commission must seek to accomplish the goal of protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has

satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

TECO stated that it would cost $47,500 per ton to add SCR to its four gas-fired boilers which are rated at over 100 MMBtu/hr heat input.

TECO incorrectly calculated the cost per ton by failing to take into account the fact that the emission reductions will continue to occur for the life of the equipment (assumed to be 15 years) rather than for only a single year. Consequently, TECO's estimated cost per ton is significantly

overstated. The 0.010 lb/MMBtu emission specification may be achievable with Tier I controls for the single burner boilers above 100 MMBtu/hr that TECO operates. There are at least three burner vendors with experience in achieving ESAD levels of NO_x in single burner gas-fired boilers, with at least two dozen retrofits. It appears unlikely that TECO will need to install SCRs because of the burner technologies offered by these vendors. Ultralow-NO_x burner technology is less expensive than retrofit of the SCR controls assumed by TECO in its cost estimate; therefore the overall cost of achieving the necessary emission reductions from TECO's boilers will be much lower.

BCCA stated that there is no analysis in the rule proposal preamble to describe the economic feasibility of the proposed retrofit limits for FCCUs, incinerators, dryers, pulping recovery furnaces, steel furnaces, kilns, or other sources. BCCA and TxOGA requested that the commission provide the economic feasibility analysis for the proposed ESADs for FCCUs. BCCA requested that the commission provide the economic feasibility analysis for the proposed ESADs for incinerators.

The cost estimates were published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8287 - 8293). The market-based control program is expected to minimize the costs necessary to achieve the required reductions. Specifically, 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 rule proposal preamble, 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 ESADs.

Regarding stationary IC engines, BCCA, EMA, ExxonMobil, GPA, Kinder Morgan, Pasadena/Donohue, TCC, Texas Eastern, TGC, and TGP stated that the rule proposal preamble cites costs for just one site and stated that this site may not be operating the replacement electric drive motors as base-load equipment. The commenters stated that other recent gas industry experience with electric drive replacement indicates the cost may be higher than cited in the rule proposal preamble. BCCA, GPA, and TGP stated that the economic feasibility cited in the preamble also relies, in part, upon the value of credits generated by shutdown of the replaced engines and stated that at a limit of 0.17 g/hp-hr, replacing engines with electric drive will generate very few credits. ExxonMobil expressed similar concerns regarding replacement of stationary IC engines with electric drive motors. EMA stated that a stationary gaseous-fueled engine rated at greater than 3,000 hp could meet the proposed limit with advanced SCR, but this control would be costly. GPA, Kinder Morgan, Texas Eastern, TGC, and TGP stated that the emission specifications are unattainable without significant capital expenditure. MECA stated that NSCR can achieve NO_x emission reductions of more than 90% from rich-burn engines or engines operated stoichiometrically at a cost of $10 - $15 per bhp, that SCR can achieve NO_x emission reductions of more than 90% from lean-burn engines at a cost of $50 - $125 per bhp, and that lean NO_x catalysts can achieve NO_x emission reductions of more than 80% from lean-burn engines at a cost of

$10 - $20 per bhp.

As described earlier in this preamble, the commission has revised the ESADs for IC engines in order to ensure that the ESADs are technically feasible without wholesale replacement of equipment, thereby significantly reducing the costs. The cost of electrification of stationary IC engines and the cost of upgraded electric transmission lines to sites was based on certified costs of a project completed in 2000 in HGA and was corroborated by an individual knowledgeable with such projects as being very representative of costs of this kind of project. An option for compliance with the ESADs is still the replacement of IC engines with electric drive motors, as in fact has already occurred at some sites due to such factors as the cost savings associated with increased automation and reduced labor costs for engine maintenance. The commission expects continuation of the trend toward replacement of additional IC engines with electric drive.

Wyman-Gordon stated that its furnace mechanical contractor estimated the cost for its five reheat furnaces and four heat treat furnaces to meet the proposed emission rates to be approximately $4.2 million to install low-NO_x burners and approximately $700,000 to adjust the burners to be compatible with the furnaces, for a total of approximately $4.9 million, and noted that this is substantially more than the commission's estimate. Wyman-Gordon commented that the EPA's ACT document, *Alternative Control Techniques Document - NO_x Emissions From Iron and Steel Mills*, states on page 5-8 that heat treat furnaces "operate at a very specific flame point and furnace geometries to achieve a specific 'set point' past which steel processing is most efficient; major problems may occur for a specific furnace without a large amount of equipment reconstruction." Wyman-Gordon stated that the

higher cost to achieve the proposed emission rates is because its furnaces have custom designed and built proprietary burners which already have very low NO_x emission rates as compared to standard burners commonly used in reheat and heat treat furnaces. Wyman-Gordon stated that because the burners are custom built, it is not possible to retrofit the burners with an "off the shelf" low-NO_x package and that instead, each burner would need to be completely rebuilt or replaced to achieve the proposed emission rates. Wyman-Gordon also stated that the new burners would have different flame characteristics than the existing burners, requiring modeling and an engineering study to determine the correct placement to achieve uniform heating in the furnaces, and that the cost estimate does not include the cost of lost production time while each furnace is out of operation.

While the commission strives to make the best cost estimate possible based on the available information, it agrees that individually-prepared vendor cost estimates are likely to be more accurate than generic cost information. Regarding the commenter's cost estimates for installation of low-NO_x burners, the commission notes that Tier I control options other than low-NO_x burners are available to reduce emissions from heat treat furnaces and reheat furnaces. 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 Texas, this is currently achieving 0.04 lb/MMBtu, with expectations of even better performance. Other control options are also available. 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 a combination of the two approaches.

There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the commission must seek to accomplish the goal of protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically

infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

BCCA stated that *U.S. EPA's Continuous Emission Monitoring System Cost Model, Version 3.0* understates the cost of NO_x CEMS. BCCA stated that industry experience with installed retrofit costs under the current Chapter 117 rules was in the $350,000 - $400,000 range. BCCA also stated that the commission underestimated the number of CEMS required since all units equipped with SCR will require installation of a NO_x CEMS. BCCA asserted that the number of new CEMS will be closer to 700, rather than 300, and, based on industry experience of $350,000 per installation and 700 new CEMS required, estimated the cost of new emission monitoring systems to be $245 million.

The EPA cost model is a flexible model which details more than 50 individual cost components associated with the purchase and installation of a CEMS. The commenters did not provide specifics to support their cost estimates, which are more than double the standard EPA model costs for a NO_x CEMS, so it is hard to evaluate these comments. CEMS vendors corroborate costs similar to the EPA model. The commission agrees that the number of CEMS/PEMS would

be closer to 700, because many of the boilers and heaters in the 40 - 100 MMBtu/hr range are expected to install SCR, which necessitates a NO_x monitor. Using the EPA cost model, the commission estimates the cost of 300 additional CEMS to be approximately $72 million.

In addition, based on vendor quotes, it appears that the cost of CEMS has been dropping, such that the EPA cost model overestimates both the initial and annual costs. Further, the adopted rules allow multiple stacks to share one CEMS, as well as allowing PEMS as an alternative to CEMS, which should further reduce the costs of complying with the adopted rules. It is generally recognized that a PEMS, which consists of equipment necessary for the continuous determination and recordkeeping of process gas concentrations and emission rates using process or control device operating parameters measurements and a conversion equation or computer program to produce results in units of the applicable emission limitation, are generally less expensive than a CEMS. Therefore, the costs estimated by the EPA's cost model could be expected to represent an upper bound of the monitoring costs.

BCCA asserted that there is no discussion or consideration of design and implementation timing issues, which will impact the economic feasibility of the required technology applications.

A phased compliance schedule was included in the adopted rules precisely to take into consideration the design and implementation timing issues. In addition, as noted earlier in this preamble, the commission extended the compliance schedule for sources other than investor-owned electric utilities to address design and implementation timing issues, thereby reducing costs.

Also as noted earlier in this preamble, 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 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 rule proposal preamble, 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 ESADs.

BCCA and ExxonMobil asserted that the commission has not considered the cost and economic consequences associated with the proposed December 31, 2004 compliance date. BCCA stated that the time between turnarounds ranges from four to seven years, depending on service, or about five years on average. ExxonMobil requested inclusion in the final rule adoption of the costs of the following: over 800 unscheduled plant shutdowns due to the December 31, 2004 compliance date; reduced future growth and capital investments in the energy industries associated with the inability to secure NO_x emission offsets for plant expansions due to the 90% NO_x reduction requirement; reduced industrial property tax revenues resulting from lower future capital investment; and lost jobs and lower wages in the energy industries resulting from lower capital investments in plants and plant shutdowns.

The commission extended the compliance schedule for sources other than investor-owned electric utilities as described earlier in order to allow implementation of emission reduction projects as efficiently as possible and reduce the unscheduled downtime and any associated costs. This will minimize the need for additional outages for installation of controls by allowing more of them to be accomplished during normal plant turnarounds, while concurrently reducing costs associated with lost production.

The adopted compliance schedule allows more than six years for achieving the required NO_x emission reductions. Based on BCCA's estimate that units undergo scheduled outages for

maintenance every five years on average, it could be expected that 85% of the units would undergo a scheduled shutdown by March 31, 2005. Owners and operators of units subject to the ESADs have been aware of the need to reduce NO_x emissions by 90% at least since May 1998 and of the specific ESADs at least since August 2000. Therefore, scheduled shutdowns in 2001 could be expected to include implementation of NO_x emission control projects. In addition, some structural work can be accomplished while a unit is operating to reduce the actual down time. Further, scheduled outages can be avoided by accelerating scheduled activities to coincide with unplanned outages. The combination of these strategies could be expected to reduce the number of additional shutdowns to install control equipment.

While the requirement to achieve 89% of the reductions by December 31, 2004 is greater than the 85% of the scheduled outages estimated to occur by this same date, it is also reasonable to expect that projects which generate the largest emission reductions and are most cost-effective will be implemented before projects which result in smaller emission reductions at a higher cost per ton than average. There is also an incentive for early implementation of projects which generate the largest emission reductions and are most cost-effective in order to create excess emission reduction credits which can be sold. The use of these newly-generated credits, in conjunction with existing emission reduction credits, can reasonably be expected to facilitate achieving 89% of the reductions by March 31, 2005 even though 85% of the scheduled outages are estimated to occur by this same date.

There are other areas in the state to locate new facilities which would not require that the new

emissions be offset. A shift from HGA to other areas may be one of the ways to deal with air quality problems in HGA.

BCCA stated that there are steps other than application of retrofit technology that must be taken to achieve the 90% reduction target, such as wholesale replacement of sources, consolidation of sources to reduce fuel firing, and shutdown of marginally economic equipment and plants. BCCA stated that it does not believe such steps are economically based emission control standards. BCCA, Equistar, Goodyear, PECO, and TPIEC stated that they do not believe that the commission considered the cost and regional economic impacts associated with such steps.

As described in detail earlier in this preamble, the commission believes the ESADs are technically feasible, albeit with engineering challenges. In a case where an owner or operator evaluates the circumstances of a particular unit and determines, for whatever reason, that equipment replacement and/or consolidation is the best option, that is a business decision which indicates that the owner or operator considers equipment replacement and/or consolidation to be the most cost-effective method of obtaining the necessary emission reductions.

As noted earlier in this preamble, there is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control.

In addition, no commenter has provided detailed revenue and cost information for either

individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

BCCA, Equistar, Lyondell, and TCC stated that post-combustion retrofit controls have limitations which will cause a decrease in operational reliability and loss of production capacity in many applications. BCCA asserted that the commission has not considered or quantified the economic consequences, such as loss of fuel and petrochemical production capacity, as a result of these technological limitations.

NESCAUM's *Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers* (June 1998) 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 operating experience discussion is, according to the NESCAUM report, "anchored in reality" rather than being mere speculation. Of the 11 Group 1 coal-fired utility boilers in the case studies, five were equipped with SCR, five were equipped with SNCR, and one was equipped with gas reburn. Of the ten Group 1 coal-fired utility boilers with SCR or SNCR, there were a total of three forced outages (all in the initial months of operation at the first electric utility boiler SNCR system) after a total of 230 boiler-

months of operation. The NESCAUM report concluded that "the experience with these technologies has been extremely positive. While each project had its challenges, the overall reliability and performance of the secondary control technologies has been extremely good. Technology suppliers appear to have addressed the concerns that have been expressed by the utility industry regarding difficulties in applying these technologies to commercial United States facilities and any impact to facility reliability." In short, there is no reason to expect a decrease in operational reliability with Tier II controls, based upon well-documented experience. Regarding potential loss of capacity, the commission believes that the combined capabilities of Tier I and Tier II technologies will operate in tandem to minimize costs and any potential loss of capacity.

As noted earlier in this preamble, there is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control.

BCCA stated that a 90% NO_x reduction target effectively eliminates the ability to create surplus point source emission reduction credits under the proposed Chapter 101 mass emissions cap and trade program to permit future business expansion in the region. BCCA stated that the proposed level of control provides little or no opportunity for future growth of stationary sources in HGA and that such a "no future growth" plan will eventually put businesses in HGA at an economic and competitive disadvantage in the global marketplace and make them non-competitive for further investment and expansion. BCCA asserted that the commission has not considered the regional economic consequences of what it called a "no future growth" plan. ExxonMobil and Texas Eastern expressed similar concerns

about growth and regional economic consequences.

The commission disagrees with the comment. As provided in the earlier specific examples of units achieving the ESADs, many of these units are operating below the ESADs. This demonstrates that it is possible to use overcompliance to create surplus point source emission reduction credits under the adopted Chapter 101 mass emissions cap and trade program. As noted earlier in this preamble, 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 facility's surplus allowances to meet emission reduction requirements.

The mass emissions cap and trade program will cap the level of NO_x emitted from stationary sources in the HGA area, thus stopping the possible growth of emissions. Any new source will be required to find and retire allowances equal to the amount of their 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 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 rule proposal preamble, 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 ESADs and will not prevent future growth. 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, which the commission expects will result in sufficient available allowances for growth.

BCCA stated that a compliance date of December 31, 2004 will effectively decrease the ethylene industry capacity by 2.8% and cost the HGA ethylene plant operators $330 million dollars in lost sales during the implementation period of 2003 - 2004 when construction would take place. BCCA asserted that this is one example of the economic costs not considered by the commission in understanding the economic impact of the point source rule. BCCA also stated that this product loss will add $1.65 million, on average, to the cost of each ethylene plant furnace SCR retrofit, more than doubling the average cost the commission estimated for a furnace SCR retrofit.

BCCA did not provide analysis of the basis for its estimated loss of ethylene capacity and lost

sales, and added cost to each ethylene plant furnace SCR retrofit. As noted earlier in this preamble, the commission revised the compliance schedule in order to allow implementation of emission reduction projects as efficiently as possible and reduce the unscheduled downtime and any associated costs. This will minimize the need for additional outages for installation of controls by allowing more of them to be accomplished during normal plant turnarounds, while concurrently reducing costs associated with lost production.

The adopted compliance schedule allows at least six years for achieving the required NO_x emission reductions. Based on BCCA's estimate of units undergoing scheduled outages for maintenance every five years on average, it could be expected that 85% of the units would undergo a scheduled shutdown by March 31, 2005. In addition, owners and operators of units subject to the ESADs have been aware of the need to reduce NO_x emissions by 90% at least since May 1998, and the specific ESADs at least since August 2000. Therefore, scheduled shutdowns in 2001 could be expected to include implementation of NO_x emission control projects. In addition, some structural work can be accomplished while a unit is operating to reduce the actual down time. Further, scheduled outages can be avoided by accelerating scheduled activities to coincide with unplanned outages. The combination of these strategies could be expected to reduce the number of additional shutdowns to install control equipment.

While the requirement to achieve 89% of the reductions by March 31, 2005 is greater than the 85% of the scheduled outages estimated to occur by this same date, it is also reasonable to expect that projects which generate the largest emission reductions and are most cost-effective will be

implemented before projects which result in smaller emission reductions at a higher cost per ton than average. There is also an incentive for early implementation of projects which generate the largest emission reductions and are most cost-effective in order to create excess emission reduction credits which can be sold. The use of these newly-generated credits, in conjunction with existing emission reduction credits, can reasonably be expected to facilitate achieving 89% of the reductions by March 31, 2005 even though 85% of the scheduled outages are estimated to occur by this same date.

There are other areas in the state to locate new facilities which would not require that the new emissions be offset. A shift from HGA to other areas may be one of the ways to deal with air quality problems in HGA.

BCCA stated that the engineering challenges associated with the retrofit of existing combustion devices with flue-gas treatment technologies add significantly to the cost of a NO_x control project, and urged the commission to make every attempt to quantify these additional costs and include them in the economic analysis associated with the proposed rules.

The comment implies that the engineering challenges associated with the retrofit of existing combustion devices with flue-gas treatment technologies add to the cost of all Tier II NO_x control projects. In fact, only some of the combustion sources which will be retrofitted with Tier II controls will have more difficult engineering challenges associated with the installation, while other installations will be relatively straightforward. For example, gas turbines constructed after

1990 typically have included extra space in the exhaust duct for the subsequent installation of Tier II controls, making the design and installation of Tier II controls much easier and, therefore, less expensive. For most older gas turbines, the heat recovery sections can be moved or low-temperature SCR added at the back end.

As noted earlier in this preamble, there is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control.

BCCA stated that the NO_x reduction potential and cost effectiveness of combustion control technologies are dependent on a number of factors including: starting NO_x emission level; safe operations conditions such as flame stability; process temperature requirements such a radiant heat release and total heat input; physical burner and combustion device geometry and burner size; fuel type quality and variability (e.g., Btu content, level of hydrogen and olefins); and construction issues such as material and equipment availability (e.g., burners, burner testing, combustion modelers, etc.).

The commission basically agrees with these comments. There is no question that there are a number of challenges in achieving the design emission specifications and that there are a variety of factors which affect the NO_x reduction potential and cost effectiveness of combustion control technologies.

As noted earlier in this preamble, 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 facility's surplus allowances to meet emission reduction requirements.

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 rule proposal preamble, 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 ESADs and will not prevent future growth. 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, which the commission expects will result in sufficient available allowances for growth.

BCCA stated that the NO_x reduction potential and cost effectiveness of SCR technology applications is dependent on a number of factors, including: the starting NO_x emission level; safe operations conditions (e.g., ammonia storage and handling); stack gas temperature, sulfur level, and dust loading, all of which affects technology selection and performance; fuel type quality and variability (e.g., presence of catalyst poisons and plugging agents); and construction issues such as combustion equipment type, physical equipment geometry, equipment availability and size, and physical plant plot space limitations. BCCA and TCC also stated that in many retrofit applications, SCR cannot simply be placed at the end of the flue-gas handling system, but must be designed and constructed to operate at the optimum point within the heat recovery system, with such equipment reconstruction adding significantly to the construction cost and to the production downtime necessary to install the project.

The commission basically agrees with these comments. There is no question that there are a number of challenges in achieving the design emission specifications and that there are a variety of factors which affect the NO_x reduction potential and cost effectiveness of SCR and other retrofit post-combustion control technologies. As noted earlier in this preamble, control options other than SCR (for example, ultralow-NO_x burner technology) are available to reduce emissions. The commission notes that ultralow-NO_x burner technology is less expensive than the SCR controls that BCCA has assumed will be necessary. Other control options are also available. Since technologies other than SCR can achieve significant emission reductions, fewer installations of SCR would be expected than either the commission or BCCA assumed in their respective cost analyses, thereby reducing the overall cost of achieving the necessary emission reductions in HGA.

As noted earlier in this preamble, 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 facility's surplus allowances to meet emission reduction requirements.

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 rule proposal preamble, 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 ESADs and will not prevent future growth. 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, which the commission expects will result in sufficient available allowances for growth.

BCCA stated that there will be many instances where the direct application of retrofit technology will not meet the desired NO_x emission targets or the cost to design the system around the engineering challenges will be prohibitive. BCCA stated that equipment replacement and consolidation would, in most cases, be more costly than if the NO_x retrofit applications were technologically and/or economically feasible. BCCA asserted that the commission has not included the cost of equipment replacement and consolidation that will be necessary as a result of the proposed emission limitations.

As described in detail earlier in this preamble, the commission believes the ESADs are technically feasible, albeit with engineering challenges. In a case where an owner or operator evaluates the circumstances of a particular unit and determines, for whatever reason, that equipment replacement and/or consolidation is the best option, that is a business decision which indicates that the owner or operator considers equipment replacement and/or consolidation to be the most cost-effective method of obtaining the necessary emission reductions.

The units with unique retrofit problems and therefore much higher retrofit costs may be fewer than this comment indicates. The capabilities of control technology continue to grow, adding more compliance options. Older equipment often faces higher costs to retrofit because of factors such as operating controls. In those cases for which replacement is the most cost effective option, there are economic benefits that will be enjoyed that offset the higher cost.

There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every

possible method of control. Rather, the commission must seek to accomplish the goal of protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass

emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

TGP stated that the commission's cost estimate for the electrification of stationary IC engines of $714/hp (not including the cost of upgraded electric transmission lines to the site, which cost approximately $700,000 per mile) overestimates the cost-effectiveness associated with electrification. TGP stated that it has undertaken such electrification projects in Louisiana, Mississippi, Tennessee, and Kentucky, and that based on its experience, the capital cost is approximately $1,099/hp to $1,211/hp. TGP stated that another author *(Economic Considerations for the Use of Electric Motors for Compression on Natural Gas Pipelines*, John P. Fagg, Second Annual Symposium, Electric Power Research Institute) has placed the capital cost for converting a natural gas driven unit to electric drive at $800/hp to $1,500/hp. GPA stated that it estimates the cost of compliance for a 4,000 hp facility to reduce NO_x emissions from 2.0 g/hp-hr to 0.17 g/hp-hr to be $70,000 per ton of NO_x controlled, which it stated is "exorbitant" and an indication that IC engines are disproportionately burdened with high control costs.

GPA incorrectly calculated the cost per ton by failing to take into account the fact that the emission reductions will continue to occur for the life of the equipment (assumed to be 15 years) rather than for only a single year. Consequently, GPA's estimated cost per ton is significantly overstated. However, as described earlier in this preamble, the commission has revised the ESADs for IC engines in order to ensure that the ESADs are technically feasible without wholesale

replacement of equipment, thereby significantly reducing the costs. The cost of electrification of stationary IC engines and the cost of upgraded electric transmission lines to sites was based on certified costs of a project completed in 2000 in HGA and was corroborated by an individual knowledgeable with such projects as being very representative of costs of this kind of project. An option for compliance with the ESADs is still the replacement of IC engines with electric drive motors, as in fact has already occurred at some sites due to such factors as the cost savings associated with increased automation and reduced labor costs for engine maintenance. The commission expects continuation of the trend toward replacement of additional IC engines with electric drive.

BCCA stated that the installation of combustion controls, such as low-NO_x burners will, in many cases, reduce the existing capacity of certain combustion devices by about 10% - 15% relative to conventional burners, and that this furnace capacity must be reestablished by addition of significant new equipment or production capacity is lost. BCCA stated that the heat input replacement cost or production loss associated with this control technology will significantly increase the overall cost of the NO_x reductions and should be included in the overall regional cost impact assessment. BCCA and Dynegy stated that a reduction in system efficiency associated with post-combustion controls increases the overall long-term cost of the NO_x controls.

BCCA did not explain how the reported 10% - 15% reduction in capacity was estimated. The commission believes that the combined capabilities of Tier I and Tier II technologies will operate in tandem to minimize costs and any potential loss of capacity. As noted earlier in this preamble,

there is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control.

The commenters did not provide details on system efficiency difference. However, the NESCAUM report indicated a 0.5% loss in heat rate with SCR, SNCR, and SNCR/SCR hybrid systems. The commission considers this to be minor in light of the associated NO_x reductions.

BCCA stated that the time required to perform SCR retrofits may extend the normal process downtime and result in additional production losses and that such production losses are not typically experienced with combustion hardware changes, which can generally be done during normal major turnarounds. BCCA asserted that the commission has not adequately addressed these issues in the analysis of technical feasibility and cost.

The implementation schedule and the technical feasibility have been analyzed separately in this adoption preamble in order to show as clearly as possible the reasoning the commission used in adopting the ESADs and in developing the compliance schedule. The commission has tried to use the term "technical feasibility" in a sense that does not depend on the schedule. What is technically feasible is a function of the state of current engineering practice. The appropriate schedule for applying the technically feasible controls is a function of the practicability (or difficulty) of a certain rate of application. In other words, control measures which are technically feasible remain so, but there needs to be a feasible schedule to apply them. Responses to

comments concerning the technical feasibility are discussed in detail earlier in this preamble under the heading of *TECHNICAL FEASIBILITY* for the various emission source categories.

The commission agrees that the time required to perform SCR retrofits may extend the normal process downtime. For this and other reasons, the commission revised the compliance schedule as described earlier in order to allow implementation of emission reduction projects as efficiently as possible and reduce the additional scheduled downtime and any associated costs. This will minimize the need for additional outages for installation of controls by allowing more of them to be accomplished during normal plant turnarounds, while concurrently reducing costs associated with lost production.

In addition, some structural work can be accomplished while a unit is operating to reduce the actual down time. Further, scheduled outages can be avoided by accelerating scheduled activities to coincide with unplanned outages. These strategies could be expected to reduce the number of additional shutdowns to install control equipment.

STATUTORY AUTHORITY

The amendment is adopted under the Texas Health and Safety Code, TCAA, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state’s air, such as the SIP; §382.014, concerning Emission Inventory, which

authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; 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.

SUBCHAPTER A: DEFINITIONS

§117.10

§117.10. Definitions.

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

(1) **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 pursuant to 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) **Electric generating facility (EGF)** - A facility that generates electric energy for compensation and is owned or operated by a person in this state, including a municipal corporation, electric cooperative, or river authority.

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

(A) All boilers, auxiliary steam boilers, and stationary gas turbines that generate electric energy for compensation; are owned or operated by a municipality or a Public Utility Commission of Texas regulated utility, or any of its successors; and are entirely located in one of the following ozone nonattainment areas:

(i) Beaumont/Port Arthur;

(ii) Dallas/Fort Worth;

(iii) Houston/Galveston; or

(B) 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.

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

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

enthalpy change of the fluid catalytic cracking unit regenerator off-gases refers to the total heat content of the gas at the temperature it enters the CO boiler, referring to the heat content at 60 degrees Fahrenheit, as being zero.

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

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

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

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

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

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

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

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

(21) **Large DFW system** - All boilers, auxiliary steam boilers, and stationary gas turbines that are located in the Dallas/Fort Worth ozone nonattainment area, 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.

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

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

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

rolling 12-month average; or

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

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

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

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

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

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

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

nonattainment area; or

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

(27) **Maximum rated capacity** - The maximum design heat input, expressed in MMBtu/hr, unless:

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

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

(C) the unit is a stationary gas turbine, in which case the manufacturer's rated heat consumption at the International Standards Organization (ISO) conditions shall be used as the

maximum rated capacity, unless limited by permit condition to a lesser heat input, in which case the limiting condition shall be used as the maximum rated capacity; or

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

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

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

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

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

(32) **Parts per million by volume (ppmv)** - All ppmv emission limits specified in this

chapter are referenced on a dry basis.

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

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

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

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

(37) **Process heater** - Any combustion equipment fired with liquid and/or gaseous fuel which is used to transfer heat from combustion gases to a process fluid, superheated steam, or water for the purpose of heating the process fluid or causing a chemical reaction. The term "process heater" does not apply to any unfired waste heat recovery heater that is used to recover sensible heat from the

exhaust of any combustion equipment, or to boilers as defined in this section.

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

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

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

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

(42) **Stationary internal combustion engine** - A reciprocating engine that remains or will remain at a location (a single site at a building, structure, facility, or installation) for more than 12

consecutive months. Included in this definition is any engine that, by itself or in or on a piece of equipment, is portable, meaning designed to be and capable of being carried or moved from one location to another. Indicia of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine being replaced is included in calculating the consecutive residence time period. An engine is considered stationary if it is removed from one location for a period and then returned to the same location in an attempt to circumvent the consecutive residence time requirement.

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

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

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

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

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

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

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

(48) **Utility boiler** - Any combustion equipment owned or operated by a municipality

or Public Utility Commission of Texas regulated utility, fired with solid, liquid, and/or gaseous fuel, used to produce steam for the purpose of generating electricity.

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

SUBCHAPTER B: COMBUSTION AT MAJOR SOURCES

DIVISION 1: UTILITY ELECTRIC GENERATION

IN OZONE NONATTAINMENT AREAS

§§117.101, 117.103, 117.105, 117.106, 117.108, 117.111, 117.113, 117.114, 117.116, 117.119, 117.121

STATUTORY AUTHORITY

The amendments and new sections are adopted under the Texas Health and Safety Code, TCAA, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air, such as the SIP; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; 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.

§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(12)(A) of this title (relating to Definitions), owned or operated by a municipality or a Public Utility Commission of Texas (PUC) regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC, located within the Beaumont/Port Arthur, Houston/Galveston, or Dallas/Fort Worth ozone nonattainment areas:

(1) utility boilers;

(2) auxiliary steam boilers; and

(3) stationary gas turbines.

(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.

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

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

(a) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, emissions of nitrogen oxides (NO_x) in excess of 0.26 pound per million (MM) Btu heat input on a rolling 24-hour average and 0.20 pound per MMBtu heat input on a 30-day rolling average while firing natural gas or a combination of natural gas and waste oil.

(b) No person shall allow the discharge into the atmosphere from any utility boiler, NO_x emissions in excess of 0.38 pound per MMBtu heat input for tangentially-fired units on a rolling 24-hour averaging period or 0.43 pound per MMBtu heat input for wall-fired units on a rolling 24-hour averaging period while firing coal.

(c) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of 0.30 pound per MMBtu heat input on a rolling 24-hour

averaging period while firing fuel oil only.

(d) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of the heat input weighted average of the applicable emission limits specified in subsections (a) - (c) of this section on a rolling 24-hour averaging period while firing a mixture of natural gas and fuel oil, as follows:

Figure: 30 TAC §117.105(d) (No change.)

Emission Limit = [a(0.26) + b(0.30)]/(a + b)

Where:

a = the percentage of total heat input from natural gas.
b = the percentage of total heat input from fuel oil.

(e) Each auxiliary steam boiler which is an affected facility as defined by New Source Performance Standards (NSPS) 40 Code of Federal Regulations (CFR), Part 60, Subparts D, Db, or Dc shall be limited to the applicable NSPS NO_x emission limit, unless the boiler is also subject to a more stringent permit emission limit, in which case the more stringent emission limit applies. Each auxiliary boiler subject to an emission specification under this subsection is not subject to the emission specifications of subsection (a) or (c) of this section.

(f) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a megawatt (MW) rating greater than or equal to 30 MW and an annual electric output in MW-hours (MW-hr) of greater than or equal to the product of 2,500 hours and the MW rating of the unit,

NO_x emissions in excess of a block one-hour average of:

(1) 42 parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis, while firing natural gas; and

(2) 65 ppmv at 15% O_2, dry basis, while firing fuel oil.

(g) No person shall allow the discharge into the atmosphere from any stationary gas turbine used for peaking service with an annual electric output in MW-hr of less than the product of 2,500 hours and the MW rating of the unit NO_x emissions in excess of a block one-hour average of:

(1) 0.20 pound per MMBtu heat input while firing natural gas; and

(2) 0.30 pound per MMBtu heat input while firing fuel oil.

(h) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler subject to the NO_x emission limits specified in subsections (a) - (e) of this section, carbon monoxide (CO) emissions in excess of 400 ppmv at 3.0% O_2, dry (or alternatively, 0.30 pound per 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:

(1) a one-hour average for units not equipped with a continuous emissions monitoring

system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

(2) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for CO.

(i) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to ten MW, CO emissions in excess of a block one-hour average of 132 ppmv at 15% O_2, dry basis.

(j) No person shall allow the discharge into the atmosphere from any unit subject to this section, ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(k) For purposes of this subchapter, the following shall apply:

(1) The lower of any permit NO_x emission limit in effect on June 9, 1993 under a permit issued pursuant to Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) and the NO_x emission limits of subsections (a) - (g) of this section shall apply, except that gas-fired boilers operating under a permit issued after March 3, 1982, with an emission limit of 0.12 pound NO_x per MMBtu heat input, shall be limited to that rate for the purposes of this subchapter.

(2) For any unit placed into service after June 9, 1993 and prior to the final compliance

date as specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas) or approved under the provisions of §117.540 of this title (relating to Phased Reasonably Available Control Technology (RACT)), as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 pursuant to Chapter 116 of this title and the emission limits of subsections (a) - (g) of this section shall apply. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.107 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

(l) This section shall no longer apply:

(1) to any utility boiler in the Beaumont/Port Arthur ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.510(a)(2) of this title;

(2) to any utility boiler in the Dallas/Fort Worth ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.510(b)(2) of this title; and

(3) in the Houston/Galveston ozone nonattainment area after the appropriate

compliance date(s) for emission specifications for attainment demonstrations given in §117.510(c)(2) of this title. For purposes of this paragraph, this means that the RACT emission specifications of this section remain in effect until the emissions allocation for a unit under the Houston/Galveston mass emissions cap are equal or less than the allocation that would be calculated using the RACT emission specifications of this section.

§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 Trading).

(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 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, 0.010; and

(B) coal-fired or oil-fired:

(i) wall-fired, 0.030; and

(ii) tangential-fired, 0.030;

(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:

(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.

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

(1) 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 (relating to Trading).

(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, an owner or operator may not use the alternative methods specified in §117.570 of this title to comply with the NO_x emission specifications of this section. In addition, the following requirements apply.

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

(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.

§117.108. 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(12)(A) of this title (relating to Definitions), that would otherwise be subject to the NO_x emission rates of §117.106 of this title must be included in the system cap.

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

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

Figure: 30 TAC §117.108(c)(1)

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

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 the system highest 30-day period in the nine months of July, August, and September 1997, 1998, and 1999;

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

(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;

(II) EGFs which qualify for a permit by rule under Chapter

106 of this title; and

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

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

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

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

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

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

$$\text{NO}_x \text{ maximum daily cap (lb/day)} = \sum_{i=1}^{N} \left(H_{Mi} \times R_i\right)$$

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.

§117.111. Initial Demonstration of Compliance.

(a) The owner or operator of all units which are subject to the emission limitations of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas) must test the units as follows.

(1) Test for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (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) Testing shall be performed in accordance with the schedules specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas).

(b) The tests required by subsection (a) of this section shall be used for determination of initial compliance with the emission limits of this division. Test results shall be reported in the units of the applicable emission limits and averaging periods. If compliance testing is based on 40 Code of Federal Regulations, Part 60, Appendix A reference methods, the report must contain the information specified in §117.211(g) of this title (relating to Initial Demonstration of Compliance).

(c) Continuous emissions monitoring systems (CEMS) or predictive emissions monitoring

systems (PEMS) required by §117.113 of this title (relating to Continuous Demonstration of Compliance) shall be installed and operational before testing under subsection (a) of this section. 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.

(d) Initial compliance with the emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.113 of this title shall be demonstrated after monitor certification testing using the NO_x CEMS or PEMS as follows:

(1) To comply with the NO_x emission limit in pound per million (MM) Btu on a rolling 30-day average, NO_x emissions from a unit are monitored for 30 successive unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission limit. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) To comply with the NO_x emission limit in pound per MMBtu on a rolling 24-hour average, NO_x emissions from a unit are monitored for 24 consecutive operating hours and the 24-hour average emission rate is used to determine compliance with the NO_x emission limit. The 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period. Compliance with the NO_x emission limit for fuel oil firing shall be determined based on the first 24 consecutive operating hours a unit fires fuel oil.

(3) For EGFs complying with §117.108 of this title (relating to System Cap), a rolling 30-day average of total daily pounds of NO_x emissions from the EGFs are monitored (or calculated in accordance with §117.108(e) of this title) for 30 successive system operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission limit. The 30-day average emission rate is calculated as the average of all daily emissions data recorded by the monitoring and recording system during the 30-day test period. There must be no exceedances of the maximum daily cap during the 30-day test period.

(4) To comply with the NO_x emission limit in pounds per hour or parts per million by volume at 15% O_2 dry basis, on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable, after CEMS or PEMS certification testing required in §117.113 of this title is used to determine compliance with the NO_x emission limit.

(5) To comply with the CO emission limit in parts per million by volume on a rolling 24-hour average, CO emissions from a unit are monitored for 24 consecutive hours and the rolling 24-hour average emission rate is used to determine compliance with the CO emission limit. The rolling 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period.

§117.113. Continuous Demonstration of Compliance.

(a) NO_x monitoring. The owner or operator of each unit subject to the emission specifications of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas), shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS), predictive emissions monitoring system (PEMS), or other system specified in this section to measure nitrogen oxides (NO_x) on an individual basis.

(b) Carbon monoxide (CO) monitoring. The owner or operator shall monitor CO exhaust emissions from each unit subject to the emission specifications of this division using one or more of the following methods:

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

(A) CEMS in accordance with subsection (c) 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:

(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 the annual relative accuracy test audit of the NO_x and diluent analyzer.

(c) CEMS requirements.

(1) Any CEMS required by this section shall be installed, calibrated, maintained, and operated in accordance with 40 CFR, Part 75 or 40 CFR, Part 60, as applicable.

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

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

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

(d) Acid rain peaking units. The owner or operator of each peaking unit as defined in 40 CFR Part §72.2, may:

(1) monitor operating parameters for each unit in accordance with 40 CFR Part 75, Appendix E, §1.1 or §1.2 and calculate NO_x emission rates based on those procedures; or

(2) use CEMS or PEMS in accordance with this section to monitor NO_x emission rates.

(e) Auxiliary boilers. The owner or operator of each auxiliary boiler as defined in §117.10 of this title (relating to Definitions) shall:

(1) install, calibrate, maintain, and operate a CEMS in accordance with this section; or

(2) comply with the appropriate (considering boiler maximum rated capacity and annual heat input) industrial boiler monitoring requirements of §117.213 of this title (relating to Continuous Demonstration of Compliance).

(f) PEMS requirements. The owner or operator of any PEMS used to meet a pollutant monitoring requirement of this section must comply with the following. The required PEMS and fuel flow meters shall be used to demonstrate continuous compliance with the emission limitations of this division.

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

(2) Monitor diluent, either oxygen or carbon dioxide:

(A) using a CEMS

(i) in accordance with subsection (b) 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 for units subject to the requirements of 40 CFR 75 shall meet the requirements of 40 CFR 75, Subpart E, §§75.40 - 75.48.

(4) Any PEMS for units not subject to the requirements of 40 CFR 75 shall meet the requirements of either:

(A) 40 CFR 75, Subpart E, §§75.40 - 75.48; or

(B) §117.213(f) of this title.

(g) Stationary gas turbine monitoring for NO_x RACT. The owner or operator of each stationary gas turbine subject to the emission specifications of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), instead of monitoring emissions in accordance with the monitoring requirements of 40 CFR 75, may comply with the following monitoring requirements:

(1) for stationary gas turbines rated less than 30 megawatt (MW) or peaking gas turbines (as defined in §117.10 of this title) which use steam or water injection to comply with the emission specifications of §117.105(g) of this title:

(A) install, calibrate, maintain and operate a CEMS or PEMS in compliance with this section; or

(B) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. The system shall be accurate to within $\pm$ 5.0%. 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 §117.105 of this title.

(2) for stationary gas turbines subject to the emission specifications of §117.105(f) of this

title, install, calibrate, maintain and operate a CEMS or PEMS in compliance with this section.

(h) Totalizing fuel flow meters. The owner or operator of units listed in this subsection shall install, calibrate, maintain, and operate totalizing fuel flow meters to individually and continuously measure the gas and liquid fuel usage. A computer which collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The units are:

(1) for units which are subject to §117.105 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 §117.106 of this title (relating to Emission Specifications for Attainment Demonstrations):

(A) any unit subject to the emission specifications of this division;

(B) any stationary gas turbine with an MW rating greater than or equal to 1.0 MW operated more than 850 hours per year (hr/yr); and

(C) any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.103(a)(2) of this title (relating to Exemptions); and

(2) for units in the Houston/Galveston ozone nonattainment area ozone nonattainment area which are subject to §117.106 of this title:

(A) utility boilers;

(B) auxiliary steam boilers; and

(C) stationary gas turbines.

(i) Run time meters. The owner or operator of any stationary gas turbine using the exemption of §117.103(a)(3) or (b) of this title shall record the operating time with an elapsed run time meter approved by the executive director.

(j) Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemptions of §117.103(a)(2) or (3) of this title, shall notify the executive director within seven days if the applicable limit is exceeded.

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

(k) Data used for compliance.

(1) After the initial demonstration of compliance required by §117.111 of this title (relating to Initial Demonstration of Compliance) the methods required in this section shall be used to determine compliance with the emission specifications of §117.105 or §117.106(a) or (b) of this title. Compliance with the emission limitations may also be determined at the discretion of the executive director using any commission compliance method.

(2) For units subject to the emission specifications of §117.106(c) of this title, the methods required in this section and §117.114 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 §117.105 of this title is selected, no unit subject to §117.105 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117.105 of this title. If compliance with §117.107 of this title is selected, no unit subject to §117.107 of this title shall be operated at an emission rate higher than that approved

by the executive director pursuant to §117.115(b) of this title (relating to Final Control Plan Procedures).

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

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

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

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

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

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

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

(c) Emission allowances.

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

(2) For units not operating with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS), the following apply.

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

(B) Retesting as specified in subsection (b) of this section may be conducted at the discretion of the owner or operator after any modification which could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas

recirculation (FGR), and fuel-lean and conventional (fuel-rich) reburn.

(C) The NO_x emission rate determined by the retesting shall establish a new emission factor to be used to calculate actual emissions 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.

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

(a) The owner or operator of utility boilers listed in §117.101 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit to the executive director a final control report to show compliance with the requirements of §117.106 of this title (relating to Emission Specifications for Attainment Demonstrations). The report must include:

(1) the section under which NO_x compliance is being established for the utility boilers within the electric generating system, either:

(A) §117.106 of this title; or

(B) §117.108 of this title (relating to System Cap); and as applicable,

(C) §117.570 of this title (relating to Trading);

(2) the methods of control of NO_x emissions for each utility boiler;

(3) the emissions measured by testing required in §117.111 of this title (relating to Initial Demonstration of Compliance);

(4) the submittal date, and whether sent to the Austin or the regional office (or both), of any compliance stack test report or relative accuracy test audit report required by §117.111 of this title which is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any utility boiler with a claimed exemption from the emission specification of §117.106 of this title.

(b) For sources complying with §117.108 of this title, in addition to the requirements of subsection (a) of this section, the owner or operator shall submit:

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

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

(A) the average daily heat input H_i specified in §117.108(c)(1) of this title;

(B) the maximum daily heat input H_{mi} specified in §117.108(c)(2) of this title;

(C) the method of monitoring emissions; and

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

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

(c) The report must be submitted by the applicable date specified for final control plans in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas). The plan must be updated with any emission compliance measurements submitted for units using continuous emissions monitoring system or predictive emissions monitoring system and complying with the system cap rolling 30-day average emission limit, according to the applicable schedule given in §117.510 of this title.

§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 executive director 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 executive director and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.111 of this title or any CEMS or PEMS performance evaluation conducted under §117.113 of this title:

(1) 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, pursuant to §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.

§117.121. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), or the carbon monoxide (CO) or ammonia limits of §117.106(d) of this title (relating to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.105 of this title or the CO or ammonia limits in §117.106(d) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) must determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through system-wide averaging at maximum capacity.

(b) Any person affected by the executive director's decision to deny an alternative case specific emission specification may file a motion for reconsideration. The requirements of §50.39 of this title (relating to Motion for Reconsideration) or §50.139 of this title (relating to Overturn Executive

Director's Decision) apply. However, only a person affected may file a motion for reconsideration. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the EPA in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas).

DIVISION 2: UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS

§117.138

STATUTORY AUTHORITY

The amendment is adopted under the Texas Health and Safety Code, TCAA, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state’s air, such as the SIP; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; 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.

§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(12)(B) of this title (relating to Definitions), that would otherwise be subject to the NO_x emission limits of §117.135 of this title must be included in the system cap.

(c) 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

§§117.201, 117.203, 117.205-117.208, 117.210, 117.211, 117.213, 117.214, 117.216, 117.219, 117.221

STATUTORY AUTHORITY

The amendments and new sections are adopted under the Texas Health and Safety Code, TCAA, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air, such as the SIP; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; 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.

§117.201. Applicability.

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

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

(2) stationary gas turbines;

(3) stationary internal combustion engines;

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

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

(6) duct burners used in turbine exhaust ducts;

(7) pulping liquor recovery furnaces;

(8) lime kilns;

(9) lightweight aggregate kilns;

(10) heat treating furnaces and reheat furnaces;

(11) magnesium chloride fluidized bed dryers; and

(12) incinerators.

§117.203. Exemptions.

(a) Units exempted from the provisions of this division (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas), except as may be specified in §117.209(c)(1) of this title (relating to Initial Control Plan Procedures), 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:

(A) used in research and testing, or used for purposes of performance verification and testing, or used solely to power other engines or gas turbines during start-ups, or operated exclusively for firefighting and/or flood control, or used in response to and during the existence of any officially declared disaster or state of emergency, or used directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals, or used as chemical processing gas turbines; or

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

(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; and

(10) diesel-fired stationary internal combustion engines.

(b) The exemptions in paragraphs (1), (2), (6)(B), (7), and (8)(A) of subsection (a) shall no longer apply in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title.

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

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

(a) No person shall allow the discharge of air contaminants into the atmosphere to exceed the emission limits of this section, except as provided in §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117.223 of this title (relating to Source Cap).

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

(A) gas-fired boilers and process heaters operating under a permit issued after March 3, 1982, with an emission limit of 0.12 pound NO_x per million British thermal units (Btu) heat input, shall be limited to that rate for the purposes of this subchapter; and

(B) gas-fired boilers and process heaters which have had NO_x reduction projects permitted since November 15, 1990 and prior to June 9, 1993 that were solely for the purpose of making early NO_x reductions, shall be subject to the appropriate emission limit of subsection (b) of this section. The affected person shall document that the NO_x reduction project was solely for the purpose of obtaining early reductions, and include this documentation in the initial control plan required in §117.209 of this title (relating to Initial Control Plan Procedures).

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

(A) the limit explicitly stated in pound NO_x per million Btu (MMBtu) of heat input by permit provision (converted from low heating value to high heating value, as necessary); or

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

(3) For any unit placed into service after June 9, 1993 and before the final compliance date as specified in §117.520 of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) or the final compliance date as approved under the provisions of §117.540 of this title (relating to Phased Reasonably Available Control Technology (RACT)), as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 pursuant to Chapter 116 of this title and the emission limits of subsections (b) - (d) of this section shall apply. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.207 or §117.223 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

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

(1) gas-fired boilers, as follows:

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

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

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

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

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

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

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

(A) based on air preheat temperature:

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

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

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

(B) based on firebox temperature:

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

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

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

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

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

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

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

Figure: 30 TAC §117.205(b)(6)

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

EL_2 = Time-weighted emission limitation for each 30-day period, in lb NO_x/MMBtu of heat input.
EL_1 = Appropriate emission limitation for gas-fired boiler from §117.205(b)(1)(A) - (F) of this title or gas-fired process heaters from §117.205(b)(2)(A) - (B) of this section, in lb NO_x/MMBtu of heat input.
1.25 = Factor used as a multiplier times the appropriate emission limitation when firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period.
T_1 = Time in hours when firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period during each 30-day period. The time period when hydrogen rich fuel is combusted must, at a minimum, be a consecutive eight-hour period to be used in the determination of T_1.
T_2 = Time in hours when firing gaseous fuel or hydrogen rich fuel (for less than eight consecutive hours) during each 30-day period;

(7) for units which operate with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.213 of this title (relating to Continuous Demonstration of Compliance), the emission limits shall apply as:

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

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

(8) for units which do not operate with a NO_x CEMS or PEMS under §117.213 of this title, the emission limits shall apply in pounds per hour, as specified in paragraph (7)(B) of this subsection.

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

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

(1) rated 150 hp or greater and located in the Houston/Galveston ozone nonattainment area; or

(2) rated 300 hp or greater and located in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment area.

(e) No person shall allow the discharge into the atmosphere from any gas-fired, lean-burn, stationary, reciprocating internal combustion engine rated 300 hp or greater and located in the Beaumont/Port Arthur ozone nonattainment area, emissions in excess of 3.0 g NO_x/hp-hr and 3.0 g CO/hp-hr, either as:

(1) a block one-hour average limit; or

(2) a 30-day rolling average limit. The owner or operator must ensure compliance with a 30-day rolling average using:

(A) a PEMS or CEMS under §117.213 of this title; or

(B) a monitoring system which:

(i) computes predicted emissions as a function of engine speed and torque using curves or equations supplied by the engine manufacturer or developed through engine testing, which:

(I) may be adjusted by engine testing; and

(II) must be shown to be consistent with the required initial and biennial compliance testing; and

(ii) monitors and records data representative of engine torque and speed at sufficient frequency to accurately compute the 30-day average NO_x.

(f) No person shall allow the discharge into the atmosphere from any boiler or process heater

subject to NO_x emission specifications in subsection (a) or (b) of this section, CO emissions in excess of the following limitations:

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

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

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

(g) No person shall allow the discharge into the atmosphere from any unit subject to a NO_x emission limit in this section, (including an alternative to the NO_x limit in this section under §117.207 or §117.223 of this title), ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(h) Units exempted from the emissions specifications of this section include the following:

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

(2) any low annual capacity factor boiler, process heater, stationary gas turbine, or

stationary internal combustion engine as defined in §117.10 of this title (relating to Definitions);

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

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

(5) duct burners used in turbine exhaust ducts;

(6) any lean-burn, stationary, reciprocating internal combustion engine located in the Houston/Galveston or Dallas/Fort Worth ozone nonattainment area;

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

(8) 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;

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

(10) 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.

(i) This section shall no longer apply:

(1) to any gas-fired boiler or process heater in the Beaumont/Port Arthur ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.520(a)(3) of this title; and

(2) in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.520(c)(2) of this title. For purposes of this paragraph, this means that the RACT emission specifications of this section remain in effect until the emissions allocation for a unit under the Houston/Galveston mass emissions cap are equal or less than the allocation that would be calculated using the RACT emission specifications of this section.

§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 (MM) Btu/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 or the following:

(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; 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;

(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, 0.17 g NO_x/hp-hr;

(B) gas-fired lean-burn engines, 0.50 g NO_x/hp-hr, except as specified in subparagraph (C) of this paragraph; and

(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;

(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; or

(B) 0.030 lb NO_x per MMBtu; and

(17) as an alternative to the emission specifications in paragraphs (1) - (16) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb NO_x per MMBtu.

(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 Trading).

(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.

(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) of this title.

(h) Prohibition of circumvention. In the Houston/Galveston ozone nonattainment area, the owner or operator of units which utilize liquid or gaseous streams containing chemical-bound nitrogen as a source of fuel or combustion air shall not direct these streams to flares or other units which are not subject to an emission specification in subsection (c) of this section, unless:

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

(2) NO_x emissions from this opt-in unit are determined using a CEMS or PEMS which meets the requirements of §117.213(e) or (f) of this title or through stack testing which meets the requirements of §117.211(e) of this title (relating to Initial Demonstration of Compliance).

§117.207. Alternative Plant-wide Emission Specifications.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations) by achieving equivalent NO_x emission reductions obtained by compliance with a plant-wide emission limitation. Any owner or operator who elects to comply with a plant-wide emission limit shall reduce emissions of NO_x from affected units so that if all such units were operated at their maximum rated capacity, the plant-wide emission rate of NO_x from these units would not exceed the plant-wide emission limit as defined in §117.10 of this title (relating to Definitions).

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

(1) For boilers and process heaters which operate with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) in accordance with §117.213 of this title (relating to Continuous Demonstration of Compliance), the emission limits shall apply in:

(A) the units of the applicable standard (the mass of NO_x emitted per unit of energy input (pound NO_x per million (MM) Btu) or parts per million by volume), on a rolling 30-day average period; or

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

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

(3) For stationary gas turbines, the emission limits shall apply as the NO_x concentration in parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis on a block one-hour average.

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

(c) An owner or operator of any gaseous and liquid fuel-fired unit which derives more than 50% of its annual heat input from gaseous fuel shall use only the appropriate gaseous fuel emission limit of §117.205 or §117.206 of this title at maximum rated capacity in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate while firing gas, calculated in accordance with subsection (a) of this section. The owner or operator shall also:

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

(2) comply with the liquid fuel emission limit of §117.205 of this title while firing liquid

fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing allowable emission rate and the liquid fuel emission limit of §117.205 of this title while operating on liquid and gaseous fuel concurrently.

(d) An owner or operator of any gaseous and liquid fuel-fired unit which derives more than 50% of its annual heat input from liquid fuel shall use a heat input weighted sum of the appropriate gaseous and liquid fuel emission specifications of §117.205 or §117.206 of this title in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate, calculated in accordance with subsection (a) of this section.

(e) An owner or operator of any unit operated with a combination of gaseous (or liquid) and solid fuels shall use a heat input weighted sum of the appropriate emission specifications of §117.205 of this title in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate, calculated in accordance with subsection (a) of this section.

(f) Units exempted from emission specifications in accordance with §117.205(h) and §117.206(g) of this title are also exempt under this section and shall not be included in the plant-wide emission limit, except as follows. The owner or operator of exempted units as defined in §117.205(h) and §117.206(g) of this title may opt to include one or more of an entire equipment class of exempted units into the alternative plant-wide emission specifications.

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

(2) The ammonia and carbon monoxide emission specifications of §117.205 and §117.206 of this title apply to the opt-in units.

(3) The individual NO_x emission limit that is to be used in calculating the alternative plant-wide emission specifications is the lowest of any applicable permit emission specification determined in accordance with §117.205(a) of this title, the specification of paragraph (4) of this subsection, or when applicable, subsection (i) of this section.

(4) The equipment classes which may be included in the alternative plant-wide emission specifications and the NO_x emission rates that are to be used in calculating the alternative plant-wide emission specifications are listed in the table titled §117.207(f) OPT-IN UNITS.

Figure: 30 TAC §117.207(f)(4)

§117.207(f) OPT-IN UNITS

Equipment Class/Description	Emission Specification
fluid catalytic cracking unit carbon monoxide (CO) boilers	50% NO_x reduction across the inlet of the CO boiler to the outlet of the CO boiler, with the outlet concentration in ppmv converted into lb NO_x/MMBtu of heat input
lean-burn, gas-fired, stationary, reciprocating internal combustion engines rated 150 hp or greater	5.0 g NO_x/hp-hr under all operating conditions
boilers or process heaters with a maximum rated capacity (MRC): 40 MMBtu/hr $\leq$ MRC $<$ 100 MMBtu/hr	the emission specifications in §117.205(a) of this title for the applicable type of unit
stationary gas turbines with a MW rating: 1.0 MW $\leq$ MW rating $<$ 10.0 MW	42 ppmv NO_x at 15% O_2, dry basis
boilers and industrial furnaces which are regulated as existing facilities by EPA at 40 Code of Federal Regulations (CFR) Part 266, Subpart H	the appropriate emission limitation in §117.205(b) of this title

(g) Solely for the purposes of calculating the plant-wide emission limit, the allowable NO_x emission rate (in pounds per hour) for each affected unit shall be calculated from the lowest of the emission specifications of §117.205 of this title, or when applicable, §117.206 of this title, or any applicable permit emission specification identified in subsection (i) of this section, as follows.

(1) For each affected boiler and process heater, the rate is the product of its maximum rated capacity and its NO_x emission specification in pound per MMBtu.

(2) For each affected stationary internal combustion engine, the rate is the product of the applicable NO_x emission specification and the engine manufacturer's rated heat input (expressed in

MMBtu/hr) at the engine's hp rating; divided by the product of the engine manufacturer's rated heat rate (expressed in Btu/hp-hr) at the engine's hp rating and $454(10^6)$.

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

Figure: 30 TAC §117.207(g)(3) (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 §117.205(c) of this title (expressed in ppmv NO_x at 15% O_2, dry basis).
%H_2O	=	the volume percent of water in the stack gases, as calculated from the manufacturer's data, or other data as approved by the executive director, at MW rating and ISO flow conditions.
%O_2	=	the volume percent of O_2 in the stack gases on a wet basis, as calculated from the manufacturer's data, or other data as approved by the executive director, at MW rating and ISO flow conditions.

(4) Each affected gas-fired boiler and process heater firing gaseous fuel which contains more than 50% hydrogen (H_2) by volume, over an annual basis, may be adjusted with a multiplier of up to 1.25 times the product of its maximum rated capacity and its NO_x emission specification of §117.205 of this title.

(A) Double application of the H_2 content multiplier using this paragraph and

§117.205(b)(6) of this title is not allowed.

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

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

(D) This paragraph is not applicable for establishing compliance with §117.206 of this title.

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

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

(2) increase limits set by permit; or

(3) establish compliance with §117.206 of this title.

(i) When using this section for establishing alternative compliance with §117.206 of this title, the individual NO_x emission limit that is to be used in calculating the alternative plant-wide emission specifications is the lowest of the specification of §117.206 of this title, the actual emission rate as of September 1, 1997, and any applicable permit emission specification:

(1) for units in the Beaumont Port Arthur ozone nonattainment area, in effect on September 10, 1993;

(2) for units in the Dallas/Fort Worth ozone nonattainment area, in effect on September 1, 1997.

§117.208. Operating Requirements.

(a) The owner or operator shall operate any unit subject to the emission limitations of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) in compliance with those limitations.

(b) The owner or operator shall operate any unit subject to the plant-wide emission limit of §117.207 of this title (relating to Alternative Plant-wide Emission Specifications) such that the assigned maximum nitrogen oxides (NO_x) emission rate for each unit expressed in units of the applicable emission limit and averaging period, is in accordance with the list approved by the executive director pursuant to §117.215 of this title (relating to Final Control Plan Procedures).

(c) The owner or operator shall operate any unit subject to the source cap emission limits of §117.223 of this title (relating to Source Cap) in compliance with those limitations.

(d) All units subject to the emission limitations of §§117.205, 117.206(a) and (b), 117.207, or 117.223 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Emission Specifications for Attainment Demonstrations; Alternative Plant-wide Emission Specifications; and Source Cap) shall be operated so as to minimize NO_x emissions, consistent with the emission control techniques selected, over the unit's operating or load range during normal operations. Such operational requirements include the following.

(1) Each boiler, except for wood-fired boilers, 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 boiler and process heater controlled with induced draft FGR to reduce NO_x emissions shall be operated such that the operation of FGR over the operating range is not restricted by artificial means.

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

(5) Each unit controlled with post combustion control techniques 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.

(6) 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.

(7) 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 after each occurrence of engine maintenance which may reasonably be expected to increase emissions, 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.

§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. EGFs are not subject to this section if electric output is entirely dedicated to industrial customers. “Entirely dedicated” may include up to two weeks per year of service to the electric grid when the industrial customers’ load sources are not operating.

(b) 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 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; and

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

(i) EGFs for which the owner or operator has submitted, under Chapter 116 of this title, an application determined to be

administratively complete by the executive director;

(ii) EGFs which qualify for a permit by rule under Chapter 106 of this title; and

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

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

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

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

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

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

(D) stationary gas turbines:

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

(ii) rated at less than 1.0 MW:

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

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

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

(F) stationary, reciprocating, dual-fuel internal combustion engines:

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

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

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

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

Figure: 30 TAC §117.210(c)(2)

$$\text{NO}_x \text{ maximum daily cap (lb/day)} = \sum_{i=1}^{N} \left(H_{Mi} \times R_i\right)$$

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 §117.213 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 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.

§117.211. Initial Demonstration of Compliance.

(a) The owner or operator of all units which are subject to the emission limitations of this division (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) must test the units as follows.

(1) Test for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions while firing gaseous fuel or, as applicable:

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

(B) liquid and solid fuel.

(2) Units which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions.

(3) Test all units belonging to equipment classes which are elected to be included in

(A) the alternative plant-wide emission specifications as defined in §117.207(f) of this title (relating to Alternative Plant-Wide Emission Specifications); or

(B) the source cap as defined in §117.223(b)(4) of this title (relating to Source Cap).

(4) Initial demonstration of compliance testing shall be performed 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).

(b) The initial demonstration of compliance tests required by subsection (a) of this section shall use the test methods referenced in subsection (e) or (f) of this section and shall be used for determination of initial compliance with the emission limits of this division. Test results shall be reported in the units of the applicable emission limits and averaging periods.

(c) Any continuous emissions monitoring system (CEMS) or any predictive emissions

monitoring system (PEMS) required by §117.213 of this title (relating to Continuous Demonstration of Compliance) shall be installed and operational before conducting testing under subsection (a) of this section. Verification of operational status shall, as a minimum, include completion of the initial relative accuracy test audit and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system.

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

(e) Compliance with the emission specifications of this division for units operating without CEMS or PEMS shall be demonstrated 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:

(1) Test Method 7E or 20 (40 Code of Federal Regulations (CFR), Part 60, Appendix A) for NO_x;

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

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

(4) Test Method 2 (40 CFR 60, Appendix A) for exhaust gas flow and following the measurement site criteria of Test Method 1, §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, §3.2 (40 CFR 60, Appendix B);

(5) 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 alternate methods as approved by the executive director and EPA; or

(6) 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:

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

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

(f) Initial compliance with the emission specifications of this division for units operating with

CEMS or PEMS in accordance with §117.213 of this title, shall be demonstrated after monitor certification testing using the CEMS or PEMS as follows.

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

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

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

(4) For units complying with §117.223 of this title, a rolling 30-day average of total daily pounds of NO_x emissions from the units are monitored (or calculated in accordance with §117.223(c) of this title) for 30 successive source operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission limit. The 30-day average emission rate is calculated as the average of all daily emissions data recorded by the monitoring and recording system

during the 30-day test period. There must be no exceedances of the maximum daily cap during the 30-day test period.

(g) Compliance stack test reports must include the following minimum contents.

(1) Introductory information. Provide background information pertinent to the test, including:

(A) company name, address, and name of company official responsible for submitting report;

(B) name and address of testing organization;

(C) names of persons present, dates and location of test;

(D) schematic drawings of the unit being tested, showing emission points, sampling sites, and stack cross section with the sampling points labeled and dimensions indicated;

(E) description of the process being sampled; and

(F) facility identification number (FIN) used to identify the unit in the final control plan.

(2) Summary information. Provide summary information, including:

(A) a summary of emission rates found, reported in the units of the applicable emission limits and averaging periods, and compared with the applicable emission limit;

(B) the maximum rated capacity, normal maximum capacity, and actual operating level of the unit during the test (in MMBtu/hr, horsepower (hp), or megawatts (MW), as applicable), and description of the method used to determine such operating level;

(C) the operating parameters of any active NO_x control equipment during the test, (for example, percent flue gas recirculation, ammonia flow rate, etc); and

(D) documentation that no changes to the unit have occurred since the compliance test was conducted that could result in a significant change in NO_x emissions.

(3) Procedure. Describe the procedures used and operation of the sampling train and process during the test, including:

(A) a schematic drawing of the sampling devices used with each component designated and explained in a legend;

(B) a brief description of the method used to operate the sampling train and

procedure used to recover samples; and

(C) deviation from reference methods, if any.

(4) Analytical technique. Provide a brief description of all analytical techniques used to determine the emissions from the source.

(5) Data and calculations. Include all data and calculations, of:

(A) field data collected on raw data sheets;

(B) log of process operating levels, including fuel data;

(C) laboratory data, including blanks, tare weights, and results of analysis; and

(D) emission calculations.

(6) Chain of custody. Include a listing of the chain of custody of the emission or fuel test samples, as applicable.

(7) Appendix. Provide:

(A) calibration work sheets for sampling equipment;

(B) collection of process logs of process parameters;

(C) brief resume/qualifications of test personnel; and

(D) description of applicable continuous monitoring system, as applicable.

(8) Monitor certification reports. Monitor certification reports must contain:

(A) information which demonstrates compliance with the certification requirements of §117.213(e) or (f) of this title for CEMS or PEMS, as applicable; and

(B) the relative accuracy test audit information specified in 40 CFR 60, Appendix B, Performance Specification 2, §9.

§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; and

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

(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 $\pm$ 5.0%.

(B) The steam-to-fuel or water-to-fuel ratio monitoring data shall constitute the method for demonstrating continuous compliance with the applicable emission specification of §117.205

or §117.207 of this title.

(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 850 hours per year exemption of §117.203(a)(6)(B) of this title shall record the operating time with an elapsed run time meter.

(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 pursuant to §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. 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.

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

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

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

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

(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.

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

(a) The owner or operator of units listed in §117.206(a) and (b) of this title (relating to Emission Specifications for Attainment Demonstrations) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.206 of this title. The report must include:

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

(A) Section 117.206 of this title;

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

(C) Section 117.570 of this title (relating to Trading);

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

(3) the emissions measured by testing required in §117.211 of this title (relating to Initial Demonstration of Compliance);

(4) the submittal date, and whether sent to the Austin or the regional office (or both), of any compliance stack test report or relative accuracy test audit report required by §117.211 of this title which is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any unit with a claimed exemption from the emission specification of §117.206 of this title.

(b) For sources complying with §117.223 of this title, in addition to the requirements of subsection (a) of this section, the owner or operator shall submit:

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

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

(A) the average daily heat input H_i specified in §117.223(b)(1) and (k) or (l) of this title;

(B) the maximum daily heat input H_{mi} specified in §117.223(b)(2) and (k) or (l) of this title;

(C) the method of monitoring emissions; and

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

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

(c) The report must be submitted to the executive director by the applicable date specified for final control plans in §117.520(a) or (b) of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas). The plan must be updated with any emission compliance measurements submitted for units using continuous emissions monitoring system or predictive emissions monitoring system and complying with the source cap rolling 30-day average emission limit, according to the applicable schedule given in §117.520 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

executive director, 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 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 low annual capacity factor exemption of §117.205(h)(2), 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;

(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; and

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

§117.221. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or the carbon monoxide (CO) or ammonia limits of §117.206(e) of this title (relating to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.205 of this title or the CO or ammonia limits in §117.206(e) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) must determine that such specifications are the result of the lowest emission limitation

the unit is capable of meeting after the application of reasonably available control technology; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through plant-wide averaging at maximum capacity.

(b) Any person affected by the executive director's decision to deny an alternative case specific emission specification may file a motion for reconsideration. The requirements of §50.39 of this title (relating to Motion for Reconsideration) or §50.139 of this title (relating to Motion to Overturn Executive Director’s Decision) apply. However, only a person affected may file a motion for reconsideration. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by EPA in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas).

SUBCHAPTER D: SMALL COMBUSTION SOURCES

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

§§117.471, 117.473, 117.475, 117.478, 117.479

STATUTORY AUTHORITY

The new sections are adopted under the Texas Health and Safety Code, TCAA, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air, such as the SIP; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; 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.

§117.471. Applicability.

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

(1) boilers and process heaters; and

(2) stationary, reciprocating internal combustion engines.

§117.473. Exemptions.

(a) This division (relating to Boilers, Process Heaters, and Stationary Engines at Minor Sources) does not apply to the following:

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

(2) the following engines:

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

(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 for firefighting and/or flood control;

(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) emergency generators that do not operate more than 100 hours per calendar year, provided that records are maintained as specified in §117.479(h) of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements); and

(I) diesel-fired engines.

(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.

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

§117.475. Emission Specifications.

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

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

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

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

(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, 0.50 gram per horsepower-hour (g/hp-hr); and

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

§117.478. Operating Requirements.

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

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

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

(4) 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.

§117.479. Monitoring, Recordkeeping, and Reporting Requirements.

(a) Totalizing fuel flow meters.

(1) The owner or operator of each boiler, process heater, or engine subject to the emission limitations of §117.475 of this title (relating to Emission Specifications) shall install, calibrate, maintain, and operate totalizing fuel flow meters to individually and continuously measure the gas and liquid fuel usage. A computer which collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer.

(2) 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 at Minor Sources).

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

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

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

(3) 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 boilers, process heaters, or engines equipped with CEMS or PEMS, the CEMS or PEMS shall be installed and operational before testing under this subsection. Verification of operational status shall, as a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(6) Initial compliance with the emission specifications of §117.475 of this title for boilers, process heaters, or engines operating with CEMS or PEMS shall be demonstrated after monitor certification testing using the NO_x CEMS or PEMS.

(7) 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 exempted based on run time under §117.473(a)(2)(H) of

this title (relating to Exemptions) or §117.478(b)(5) of this title. The records shall be maintained for at least two years and shall be made available upon request to representatives of the executive director, EPA, or any local air pollution control agency having jurisdiction.

SUBCHAPTER E: ADMINISTRATIVE PROVISIONS

§§117.510, 117.520, and 117.534

STATUTORY AUTHORITY

The amendments and new section are adopted under the Texas Health and Safety Code, TCAA, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state’s air, such as the SIP; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; 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.

§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 pursuant to 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) Section 117.108 of this title (relating to System Cap); or

(II) Section 117.570 of this title (relating to Trading);

(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-) Section 117.108 of this title (relating to System Cap); or

(-b-) Section 117.570 (relating to Trading);

(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 pursuant to 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) the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date), install any totalizing fuel flow meters, and emissions monitors required by §117.114 of this title; 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 pursuant to §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 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 46% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.108 of this title;

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

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

(C) For any unit subject to §117.106(c) of this title for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph (2)(A)(ii) of this subsection, the owner or operator shall submit to the executive director as soon as practicable, but no later than March 31, 2007, the results of

(i) stack tests conducted pursuant to §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.

§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) (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 Trading);

(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 subparagraphs (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) the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date), install any totalizing fuel flow meters, and emissions monitors required by §117.114 of this title; 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 pursuant to §117.211 of this title; or, as applicable,

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

title;

(B) The owner of 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 that at least 44% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.210 of this title;

(II) March 31, 2005, demonstrate that at least 89% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day

average emissions measured in the 1997 - 1999 period and the system cap limit of §117.210 of this title; and

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

(C) For any units subject to §117.206(c) of this title for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph (2)(A) of this subsection, the owner or operator shall submit to the executive director as soon as practicable, but no later than March 31, 2007, the results of:

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

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

(D) For non-EGFs, the owner or operator shall comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) as soon as practicable, but no later than the appropriate dates specified in that program.

§117.534. Compliance Schedule for Boilers, Process Heaters, and Stationary Engines 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 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 required by §117.479 of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements) and begin keeping records of fuel usage at the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date);

(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 pursuant to §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 pursuant to §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; and

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

(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 required by §117.479 of this title and begin keeping records of fuel usage at the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date);

(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 pursuant to §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; and

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