The Texas Natural Resource Conservation Commission (TNRCC or commission) proposes 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 proposes 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 proposes new §§117.471, 117.473, 117.475, 117.478, and 117.479 in Subchapter D, to be added as a new Division 2, concerning Boilers, Process Heaters, and Stationary Engines at Minor Sources. The proposed revisions to Chapter 117 and to the state implementation plan (SIP) would 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 engines; fluid catalytic cracking units (including catalyst regenerators and associated carbon monoxide (CO) boilers and furnaces); pulping liquor recovery furnaces, lime kilns, lightweight aggregate kilns, heat treating furnaces, reheat furnaces, magnesium chloride fluidized bed dryers, incinerators, and hazardous waste-fired boilers and industrial furnaces (BIF units). The commission proposes 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 proposed revisions 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 PROPOSED RULES

The HGA ozone nonattainment area is classified as Severe-17 under the 1990 Amendments to the FCAA (42 USC), and therefore is required to attain the one-hour ozone standard of 0.12 parts per million (ppm) by November 15, 2007. 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. 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 statewide 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 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.

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.

The current SIP revision contains rules, enforceable commitments, and photochemical modeling analyses 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.

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 Houston nonattainment area will need to ultimately reduce $NO_x$ more than 750 tons per day (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. Point source $NO_x$ rules also should contribute to a successful demonstration of transportation conformity in the HGA area.

The commission solicits comment on additional flexibilities relating to rule content and implementation which have not been addressed in this or other concurrent rulemakings. These flexibilities may be available for both mobile and stationary sources. Additional flexibilities may also be achieved through innovative and/or emerging technology which may become available in the future. Additional sources of funds for incentive programs may become available to substitute for some of the measures considered here.

The attainment demonstration modeling produces a target emission rate of about 66.7 tons of $NO_x$ per day in 2007 from industrial point sources. 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 7/13/00**

| Category | 1997 Emissions (tpd) | % of Total Point | Chapter 117 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 - 0.030 |
| Turbines (+Duct Burners) | 155.65 | 23.3 | 17%; 30 tpd | 60%; 93.8 tpd | 89%; 138 tpd | 91%; 141 tpd | 0.015 |
| 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 | 56%; 48.4 tpd | 75%; 65 tpd | 91%; 79 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%; 20 tpd | various |
| Overall Point Source | 667.56 | 100.0 | 12%; 91 tpd | 42%; 279 tpd | 84%; 561 tpd | 90%; 599 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 by Subcategory 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 BY SUBCATEGORY**
**FOR HOUSTON/GALVESTON NONATTAINMENT AREA COUNTIES**

| 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 | 90%; 00.26 tpd | 98%; 00.29 tpd | 0.010 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 | 6.86 | | 62 | 60%; 4.12 tpd | 90%; 6.17 tpd | 90%; 6.17 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 |
| 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%; 93.76 tpd | 89%; 138.14 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 | 14.93 | | 216 | 49%; 7.32 tpd | 86%; 12.84 tpd | 86%; 12.84 tpd | 0.015 lb/MMBtu |
| <100MMBtuh | 6.98 | | 726 | 62%; 4.33 tpd | 0%; 0 tpd | 62%; 4.33 tpd | 0.036 lb/MMBtu |
| Gas-fired <40 MMBtuh | 0.05 | | 1 | 33%; 0.02 tpd | 85%; 0.04 tpd | 90%; 0.04 tpd | 2 lb/M gal |
| Oil-fired | 110.12 | 16.5 | 1367 | 50%; 54.87 tpd | 84%; 92.23 tpd | 88%; 96.56 tpd | |
| Total Process Heaters | | | | | | | |

| 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 | | | | | | | |
| Gas-fired at sites ≥3,000 hp | 73.10 | | 343 | replace w/electric | replace w/electric | 98%; 71.46 tpd | 0.17 g/hp-hr |
| Gas-fired at sites <3,000 hp | 7.60 | | 118 | 60%; 4.57 tpd | 80%; 6.10 tpd | 92%; 7.04 tpd | 0.50 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 | 60%; 0 tpd | 80%; 0 tpd | 92%; 0 tpd | 0.50 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 | 56%; 48 tpd | 75%; 65 tpd | 91%; 78.50 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 | 12.28 | | 41 | 0%; 0 tpd | 81%; 9.95 tpd | 81%; 9.95 tpd | 0.015 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 | 90%; 0.91 tpd | 90%; 0.91 tpd | 0.020 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%; 74.82 tpd | 92%; 79.14 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 | | 14 | 0%; 0 tpd | 90%; 13.44 tpd | 90%; 13.44 tpd | 10 ppmv @0%O2 |
| Incinerators ≥40 MMBtuh | 4.02 | | 23 | 0%; 0 tpd | 90%; 3.62 tpd | 90%; 3.62 tpd | 10% of '97 rate |
| 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 | | 2 | 35%; 0.06 tpd | 0%; 0 tpd | 35%; 0.06 tpd | 0.09 lb/MMBtu |
| Steel Furnace ≥20 Reheat | 0.66 | | 7 | 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 | 1335 | 2%; 0.69 tpd | 58%; 19.10 tpd | 60%; 19.79 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 internal combustion engines; fluid catalytic cracking units (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; and BIF units.

To develop the information in this table and analyze the reductions obtainable by potential $NO_x$ emission rate limits (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 1997 ozone season 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 can not be reasonably controlled (for example, flares), it is necessary that the larger emission categories, especially electric utility boilers, stationary gas turbines, heaters, engines, and ICI boilers, achieve more than a 90% reduction in order for the overall emission reductions from $NO_x$ point sources to meet the 90% goal 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 rate limits 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, being noticed for public hearings and comment concurrently in a separate section of this issue of the *Texas Register*.

SECTION BY SECTION DISCUSSION

The primary purpose of the proposed revisions to Chapter 117 and to the SIP is to establish new emission limits for the ozone attainment demonstrations. However, another purpose of these proposed 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, and stationary internal combustion engines and stationary gas turbines. The proposed revisions will establish emission limits for boilers; process heaters and furnaces; stationary internal combustion engines and stationary gas turbines; duct burners used in turbine exhaust ducts; fluid catalytic cracking units (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; and BIF units which are currently exempt from the $NO_x$ RACT limits in §117.105 and §117.205. While the proposed attainment demonstration emission limits are more stringent than RACT, these limits 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 proposed changes to §117.10, concerning Definitions, 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 proposed changes to §117.10 also add a definition of "electric generating facility (EGF)" which is consistent with the corresponding definition in §117.330(12), concerning Definitions. Subsequent definitions in §117.10 are renumbered to accommodate the proposed new definition of "electric generating facility (EGF)."

In addition, the proposed changes 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 proposed changes 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 internal combustion engines. Because the emission reductions approaching the tpd emission rate required by the attainment demonstration necessitate further reductions from essentially all categories, the proposed revisions broaden the applicability of the definition of unit to include any other stationary source of $NO_x$ at a major source. Finally, the proposed changes to §117.10 revise the renumbered §117.10(34) 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(10) and the usage of these terms in the rules.

The proposed changes 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 proposed changes 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(38), and update a reference to the renumbered §117.10(12).

The proposed changes 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 proposed changes 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 proposed 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, is proposed to be 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 proposed changes 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 limits of §117.106, concerning Emission Specifications for Attainment Demonstrations, and §117.108. This revision is proposed 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 proposed broadening of the exemption in the renumbered §117.103(c) will address this concern.

The proposed 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 less than ten megawatts (MW) in capacity and which emit no more than 0.015 lb $NO_x$/MMBtu heat input. The commission is proposing this exemption to facilitate the distributed generation of electricity through authorization of relatively small electricity-producing units.

The proposed changes 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. In addition, the proposed changes to §117.105 correct the title of §117.510 in §117.105(k)(2). The proposed changes to §117.105 also 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 limits. This will avoid any potential conflicts of RACT limits and the new more stringent attainment demonstration limits.

The proposed changes to §117.106 specify new $NO_x$ limits for electric utility boilers located in HGA. The proposed limits are essential components of and consistent with the HGA Attainment Demonstration SIP, being noticed for public hearings and comment concurrently in a separate section of this issue of the *Texas Register*. The proposed emission limits 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 limits were developed is described in the Background and Summary of the Factual Basis for the Proposed Rules section of this preamble.

The proposed revisions 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 proposed new §117.106(c).

The proposed $NO_x$ emission limits for electric utility boilers located in HGA are being added as a new §117.106(c) and are based on a daily rate for electric utility boilers. 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 limits of §117.106(c) also apply as specified in §117.108 and in the emissions banking and trading program of Chapter 101, Subchapter H, Division 3, concerning Mass Emissions Cap and Trade Program, being noticed for public hearings and comment concurrently in this issue of the *Texas Register*.

The proposed limits of §117.106(c) for electric utility boilers 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 proposed $NO_x$ emission limit for electric utility boilers in HGA is discussed in the Background and Summary of the Factual Basis for the Proposed Rules section of this preamble. The proposed emission limits 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, and 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 will achieve a 93% emission reduction and generate an estimated 184.26 tpd $NO_x$ reductions from HGA electric utility boiler emissions. The proposed 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.

The proposed emission limits of 0.015 lb $NO_x$/MMBtu heat input for stationary gas turbines will achieve a 91% emission reduction in conjunction with the proposed emission limit of 0.015 lb $NO_x$ per MMBtu heat input for stationary gas turbines and duct burners in §117.206(c)(11) and (12), respectively, concerning Emission Specifications for Attainment Demonstrations, and generate an estimated total of 141.00 tpd $NO_x$ reductions from these units in HGA, based on the 1997 emissions inventory. The proposed 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 proposed to be renumbered as §117.106(d) and (e). The proposed revisions 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 proposed $NO_x$ limits. 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 proposes to exclude 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 revisions 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 emissions banking and trading program of Chapter 101, Subchapter H, Division 3, being noticed for public hearings and comment concurrently in this issue of the *Texas Register*. The owners and operators of the equipment addressed by these proposed Chapter 117 revisions will be required to use the compliance flexibility provided by the proposed 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 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 proposed §117.106 emission limits 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 proposed changes 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 proposed changes to §117.108 also revise §117.108(a) - (i) and (k) by replacing references to "utility boiler" with the term "EGF." In addition, the proposed changes 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 proposed changes 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 proposed changes 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 proposed changes 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 solicits 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.

The proposed changes 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 proposed changes 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 proposed changes 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 proposed changes 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(37).

In addition, the proposed changes 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 proposed

Chapter 101 mass emissions cap and trade program. 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 proposed changes 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 proposed changes 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 attainment demonstration emission specifications 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 proposed revisions to the catchlines in §117.113(l) clarify that this subsection applies to the $NO_x$ RACT emission specifications of §117.105.

The proposed new §117.114 applies to units in HGA which are subject to the attainment demonstration limits of §117.106(c) and specifies monitoring and testing requirements. The proposed new §117.114(a) requires monitoring for $NO_x$, CO, and fuel flow as specified in §117.113(a) - (f) and (g). The proposed new §117.114(b) requires testing of each unit which is subject to the emission limits 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 proposed Chapter 101 mass emissions cap and trade program, the proposed §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 proposed Chapter 101 mass emissions cap and trade program.

The proposed changes to §117.116, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, revise the requirements in §117.116(a)(1), (2), and (5) to apply to auxiliary boilers and stationary gas turbines in HGA and, in conjunction with these changes, revise

§117.116(a) to refer to units listed in §117.101, rather than to utility boilers listed in §117.101. While this change broadens the scope of the final control plan procedures, it will not add any requirements to auxiliary boilers and stationary gas turbines in BPA and DFW because the proposed changes to §117.116(a)(1), (2), and (5) specify that these paragraphs only apply to utility boilers in BPA and DFW. In addition, the remaining paragraphs in §117.116 do not apply to auxiliary boilers and stationary gas turbines in BPA and DFW.

The proposed changes to §117.116 also revise §117.116(a)(1) to reference the Chapter 101 mass emissions cap and trade program being proposed concurrently in this issue of the *Texas Register*. This revision is necessary because the owners and operators of the equipment addressed by these proposed Chapter 117 revisions will be required to use the compliance flexibility provided by the proposed 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 proposed changes to §117.116 also revise §117.116(a)(3) and (4) to add a reference to the requirements of §117.114.

The proposed changes 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 proposed changes 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(37).

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

The proposed changes 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: fluid catalytic cracking units (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; 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 proposed changes 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 regulated utility, are included in the applicability of §117.201, rather than §117.101.

The proposed changes 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 proposed §117.206(c)(14), which establishes emission limits for these units in HGA.

In addition, the exemption in the existing §117.203(3) for electric utility power generating boilers is proposed for deletion. 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 proposed changes to the renumbered §117.203(a)(4) and (5) specify that the exemptions for incinerators, fume abaters, 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 revisions to the renumbered §117.203(a)(4) and (5) are necessary for consistency with the proposed §117.206(c)(12) - (16), which establish emission limits for certain units in these categories in HGA.

The proposed changes 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 proposed 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 proposed changes to §117.203 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 the proposed §117.206(c), which establishes emission limits for these units in HGA.

The proposed 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 less than ten MW in capacity and which emit no more than 0.015 lb $NO_x$/MMBtu heat input. The commission is proposing this exemption to facilitate the distributed generation of electricity through authorization of relatively small electricity-producing units.

The proposed changes 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 proposed change is based on a rule interpretation (Code Number R7-205.001) made by the agency's Air Rule Interpretation Team.

The proposed changes 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 (33), respectively.

In addition, the proposed changes 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 proposed changes 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 proposed changes to §117.205 revise the language for fluid catalytic cracking units and duct burners in §117.205(h)(4) and (5) for consistency with the corresponding language in §117.201(4) and (6). The proposed changes to §117.205 also add new paragraphs (8) - (11) for new units placed into service after November 15, 1992; ICI boilers and process heaters with a maximum rated capacity of less than 40 MMBtu per hour; 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 internal combustion engines with a horsepower (hp) rating of less than 150 hp and 300 hp in HGA and BPA, respectively.

Finally, the proposed changes 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 limit. This will avoid any potential conflicts of RACT limits and the new more stringent attainment demonstration limits.

The proposed changes 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 proposed changes to §117.206(b)(2) abbreviate the terms "horsepower" and "carbon monoxide."

The proposed changes to §117.206, add a new §117.206(c) which specifies $NO_x$ limits for boilers, process heaters, stationary internal combustion engines, stationary gas turbines, fluid catalytic cracking units (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 at major sources of $NO_x$ in HGA. For units in HGA, the emission limits in the new §117.206(c) will be used in the proposed Chapter 101, Subchapter H, Division 3, to establish emission allocations and shall be the lower of any applicable permit limit or the emission limits described in the following paragraphs.

The proposed limits are essential components of and consistent with the HGA Attainment Demonstration SIP, being noticed for public hearings and comment concurrently in a separate section of this issue of the *Texas Register*. The proposed emission limits 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 proposed revisions 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 limits were developed is described in the Background and Summary of the Factual Basis for the Proposed Rules section of this preamble.

The proposed emission limits 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 proposed emission limit in §117.206(c)(2) of ten ppmv $NO_x$ (at 0.0% $O_2$, dry basis) for fluid catalytic cracking units (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.

The proposed emission limit in §117.206(c)(3) of 0.015 lb $NO_x$ per MMBtu heat input for BIF units will achieve an 81% $NO_x$ emission reduction and generate an estimated 9.95 tpd $NO_x$ reductions in HGA, based on the 1997 emissions inventory.

The proposed emission limit 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 proposed emission limit in §117.206(c)(5) of 0.020 lb $NO_x$ per MMBtu heat input for wood fuel-fired boilers will achieve a 90% $NO_x$ emission reduction and generate an estimated 0.91 tpd $NO_x$ reductions in HGA, based on the 1997 emissions inventory.

The proposed emission limit 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 proposed emission limit 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 proposed emission limits 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 proposed emission limits for stationary reciprocating internal combustion engines in §117.206(c)(9) are: 0.17 g $NO_x$/hp-hr for gas-fired engines at sites with a total hp rating of 3,000 hp or more in 1997 or later; 0.50 g $NO_x$/hp-hr for gas-fired engines at sites with a total hp rating of less than 3,000 hp in 1997 or later; 0.50 g $NO_x$/hp-hr for existing dual-fuel, stationary reciprocating internal combustion engines; and 0.17 g $NO_x$/hp-hr for dual-fuel, stationary reciprocating internal combustion engines initially placed into service after December 31, 2000. These emission limits will achieve a 94% $NO_x$

emission reduction and generate an estimated 78.50 tpd $NO_x$ reductions in HGA, based on the 1997 emissions inventory.

The proposed emission limits 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 will achieve a 91% $NO_x$ emission reduction in conjunction with the proposed emission limit 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 141.00 tpd $NO_x$ reductions in HGA, based on the 1997 emissions inventory.

The proposed emission limit for pulping liquor recovery furnaces in §117.206(c)(12) of 0.050 lb $NO_x$ per MMBtu heat input 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 proposed emission limits 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 proposed emission limits 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 proposed emission limit for magnesium chloride fluidized bed dryers in §117.206(c)(15) of a 90% reduction from the emission factor used to calculate the 1997 ozone season 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 proposed emission limit for incinerators in §117.206(c)(16) of a 90% reduction from the emission factor used to calculate the 1997 ozone season daily $NO_x$ emissions will achieve a 61% $NO_x$ emission reduction and generate an estimated 3.62 tpd $NO_x$ reductions in HGA, based on the 1997 emissions inventory.

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 proposed changes 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 (33), respectively. For HGA, a new §117.206(d)(2) specifies that the averaging time for the attainment demonstration emission limits 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 proposed $NO_x$ 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 proposed change 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.

With the exception of the availability of alternative CO and ammonia limits through §117.221, the revisions 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 noticed for public hearings and comment concurrently in this issue of the *Texas Register*. The owners and operators of the equipment addressed by these proposed Chapter 117 revisions will be required to use the compliance flexibility provided by the proposed 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 proposed changes to §117.206 also 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 proposed changes 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.

The proposed changes to §117.207, concerning Alternative Plant-wide Emission Specifications, update cross-references to renumbered rules. The proposed changes 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 (33), respectively.

In addition, the proposed changes 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 proposed changes 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(37) and (38), respectively.

Finally, the proposed changes 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 proposed changes 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, and 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(37).

The proposed 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 proposed new §117.210, would create a flexible method of complying with the $NO_x$ emission specifications proposed in §117.206 for units which meet the definition of EGF. The proposed section is patterned on the existing source cap compliance option in §117.108 for electric utilities. The proposed 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 proposed changes to §117.211, concerning Initial Demonstration of Compliance, 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 proposed changes 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. 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 proposed 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 proposed changes 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)(10) - (11), and revise §117.213(b)(2)(A) and §117.213(c)(2)(A) to reflect the addition of the new §117.205(h)(8) - (11). 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 proposed changes to §117.213 also add new §117.213(c)(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 proposed changes 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 attainment demonstration emission specifications 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 proposed changes to §117.213 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(37); and revise §117.213(i) to reflect the renumbering of §117.203(6)(B) as §117.203(a)(6)(B).

Finally, the proposed revisions 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 proposed new §117.214 applies to units in HGA which are subject to the attainment demonstration limits of §117.206(c) and specifies monitoring and testing requirements. The proposed new §117.214(a) requires monitoring for $NO_x$, CO, and fuel flow as specified in §117.213(a) and (c) - (f). The proposed new §117.214(b) requires testing of each unit which is subject to the emission limits of §117.106(c). The testing requirements are consistent with the testing previously required of these units for $NO_x$ RACT under §117.211.

Regarding emission allowances for the proposed Chapter 101 mass emissions cap and trade program, the proposed §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 proposed Chapter 101 mass emissions cap and trade program.

The proposed changes to §117.216, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, revise §117.216(a)(1) to reference the proposed system cap of 117.210 and the Chapter 101 mass emissions cap and trade program being proposed concurrently in this issue of the *Texas Register*. This revision is necessary because the owners and operators of the equipment addressed by these proposed Chapter 117 revisions will be required to use the compliance flexibility provided by the proposed 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 proposed changes to §117.219, concerning Notification, Recordkeeping, and Reporting Requirements, amend §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 proposed changes 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.

In addition, the proposed changes 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(37).

The proposed changes 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(38), 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(37).

In addition, the proposed revisions to §117.219(f) also 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). Finally, the proposed changes to the renumbered §117.219(f)(3)(A)(i) correct a typographical error in a reference to §117.208(d)(7).

The proposed changes 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 proposed 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 internal combustion 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 proposed limits are essential components of and consistent with the HGA Attainment Demonstration SIP, being noticed for public hearings and comment concurrently in a separate section of this issue of the *Texas Register*. The proposed emission limits 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 limits were developed is described in the Background and Summary of the Factual Basis for the Proposed Rules section of this preamble.

The proposed 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 internal combustion 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 proposed new §117.473 exempts boilers and process heaters with a maximum rated capacity of 2.0 MMBtu/hr or less. This exemption level is proposed because units with a maximum rated capacity of

2.0 MMBtu/hr or less are already regulated under Subchapter D, Division 1, concerning Water Heaters, Small Boilers, and Process Heaters.

In addition, the following engines are exempt in the proposed 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 proposed new §117.473 also exempts stationary reciprocating internal combustion engines with a hp rating of 50 hp or less.

In addition, the proposed 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 proposed 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 less than ten MW in capacity and which emit no more than 0.015 lb $NO_x$/MMBtu heat input. The commission is proposing this exemption to facilitate the distributed generation of electricity through authorization of relatively small electricity-producing units.

The proposed new §117.475 establishes a proposed emission limit 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 proposed new §117.475 also establishes a proposed emission limit of 0.50 g $NO_x$/hp-hr for gas-fired stationary reciprocating internal combustion engines in HGA at non-major stationary sources of $NO_x$.

The proposed new §117.478 specifies techniques to be used to minimize $NO_x$ emissions. The proposed §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 proposed 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 proposed 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 proposed 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 proposed new §117.478(b)(5) requires engines to be checked for proper operation measuring and recording $NO_x$ 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. The proposed 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 proposed new §117.478(b)(5) allows the use of portable $NO_x$ analyzers.

The proposed 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 proposed 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 proposed Chapter 101 mass emissions cap and trade program.

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

The proposed new §117.479(e) specifies the testing requirements for boilers, process heaters, and engines which are subject to the emission limits of §117.475. These requirements are based upon the existing requirements of §117.211. The proposed §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 proposed Chapter 101 mass emissions cap and trade program.

The proposed 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 proposed Chapter 101 mass emissions cap and trade program.

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

The proposed changes 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 proposed emission specifications for attainment demonstrations. The commission is proposing a staged four-year implementation schedule for compliance with the new HGA emission specifications. First, one-third of the total reductions required to comply with the attainment demonstration emission specifications is required by December 31, 2002. The second one-third of the reductions is required by December 31, 2003. The final one-third of the reductions is required by December 31, 2004. A combination of combustion controls and flue gas cleanup controls will be necessary on many units.

The proposed revisions 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 before the critical

2005 ozone season. To qualify for this compliance date extension, a boiler must be designated by the Public Utility Commission of Texas 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 proposed changes 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 proposed changes to §117.510 also make a variety of minor punctuation corrections throughout the section. Finally, the proposed changes 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 proposed changes 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 proposed emission specifications for attainment demonstrations. The commission is proposing a staged four-year implementation schedule for compliance with the new HGA emission specifications. First, one-third of the total reductions required to comply with the attainment demonstration emission specifications is required by December 31, 2002. The second one-third of the reductions is required by December 31, 2003. The final one-third of the reductions is required by December 31, 2004. A combination of combustion controls and flue gas cleanup controls will be necessary on many units.

In addition, the proposed changes 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 proposed changes 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 proposed changes 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 proposed new §117.534 specifies the compliance schedule for boilers, process heaters, and stationary engines at minor sources in HGA.

PUBLIC UTILITY REGULATORY ACT DETERMINATION

As described earlier in this preamble, the commission proposes these revisions to Chapter 117 and the SIP in order to reduce $NO_x$ emissions and demonstrate attainment in the HGA ozone nonattainment area. Accordingly, the commission makes the following determination, as required by the Public Utility Regulatory Act (PURA), Texas Utilities Code (TUC), §39.263(c)(1)(A) and §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.

FISCAL NOTE:  COSTS TO STATE AND LOCAL GOVERNMENTS

John Davis, Technical Specialist in the Strategic Planning and Appropriations Section, has determined that for the first five-year period the proposed amendments are in effect, there will be no significant fiscal implications for most units of state government and most units of local government as a result of administration or enforcement of the proposed amendments.  However, there will be significant fiscal implications to the University of Houston and Baylor College of Medicine because they will be required to install emission controls on stationary sources of $NO_x$ emissions as a result of the proposed rules.

The proposed amendments would require a wide variety of stationary sources of $NO_x$ emissions in HGA 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; ICI boilers; duct burners used in turbine exhaust ducts; process heaters and furnaces; stationary internal combustion engines; fluid catalytic cracking units (including catalyst regenerators and associated CO boilers and furnaces); pulping liquor recovery furnaces; lime kilns; lightweight aggregate kilns; heat treating and reheat furnaces; magnesium chloride fluidized bed dryers; incinerators; and BIF units.

These standards and specifications are part of the strategy to reduce emissions of $NO_x$ necessary for the counties in the HGA ozone nonattainment area to be able to demonstrate attainment with the NAAQS for ozone. The proposed amendments are a necessary and essential component of the proposed HGA Attainment Demonstration SIP. A SIP is a plan developed for any region where existing (measured and estimated) ambient levels of pollutant exceeds the levels specified in a national standard. The plan sets forth a control strategy that provides emission reductions necessary for attainment and maintenance of the national standards.

For sources with a design capacity to emit $NO_x$ in amounts greater than or equal to ten tons per year (tpy), the commission is proposing a staged four-year implementation schedule for compliance with the new HGA emission specifications. First, one-third of the total reductions required to comply with the attainment demonstration emission specifications are required by December 31, 2002. The second one-third of the reductions are required by December 31, 2003. The final one-third of the reductions are required by December 31, 2004. For sources with a design capacity to emit $NO_x$ in amounts less than ten tpy, the final compliance date is December 31, 2002.

Most of the sources which will have to comply with the proposed rules are currently subject to air permits and are already being inspected for compliance. Consequently, only a limited number of additional facilities will need to be inspected for compliance with the proposed amendments. The commission anticipates that enforcement of these rules will not significantly increase the number of facilities currently inspected by the state and local governments.

The commission estimates that there may be other state and local government facilities affected by the proposed amendments that have not been identified in this fiscal note. State and local government facilities with equipment affected by the proposed amendments would be required to adhere to the proposed standards. Costs to those units would be similar as presented in this fiscal note.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that four ICI boilers at the Baylor College of Medicine and three ICI boilers at the University of Houston and will be affected by the proposed amendments. The ICI boilers at the Baylor College of Medicine have a maximum capacity less than 40 MMBtu/hr. The new $NO_x$ emission standard for this type of boiler is 0.036 lb/MMBtu. It is estimated that the these boilers will have to reduce emissions by 0.01 tpd through the use of combustion modifications, such as low-$NO_x$ burners (LNB) or FGR. Total capital costs for the combustion modifications are estimated at $3,100 per MMBtu/hr, and the annual costs are estimated at $600 per MMBtu/hr. These cost estimates were derived from cost models on page E-23 of EPA's alternative control techniques (ACT) document, *Alternative Control Techniques Document -- $NO_x$ Emissions from Industrial/Commercial/Institutional (ICI) Boilers*. Total capital costs for the Baylor College of Medicine ICI gas-fired boilers are approximately $257,000 with an annual cost of $52,200. The average capital cost for each affected boiler is approximately $65,000 with an average annual cost of $13,000. Cost effectiveness for the proposed emission reductions is approximately $15,000 per ton of $NO_x$ reduced.

The three ICI boilers at the University of Houston are larger units, with capacities greater than 40 MMBtu/hr but less than 100 MMBtu/hr. The new $NO_x$ emission standard for this type of boiler is

0.015 lb/MMBtu. It is estimated that these ICI boilers will have to reduce emissions by 0.04 tpd through the use of SCR. In order to determine costs related to these ICI boilers, a spreadsheet provided by NESCAUM was used. This spreadsheet determines SCR costs based on the capacity of the affected unit. Capital costs for SCR on these boilers ranges from $70/kilowatt (kW) to $76/kW. Total capital costs for the University of Houston as a result of the proposed amendments are approximately $1.4 million with an annual cost of $384,000. The average capital cost for each affected boiler is approximately $467,000 with an average annual cost of $128,000. Cost effectiveness for the proposed emission reductions is approximately $27,000 per ton of $NO_x$ reduced.

PUBLIC BENEFIT AND COSTS

Mr. Davis has also determined that for each year of the first five years the proposed amendments to Chapter 117 are in effect, the public benefit anticipated from enforcement of and compliance with the proposed amendments will be a reduction of public exposure to $NO_x$ emitted from affected stationary sources, a reduction of ground-level ozone in ozone nonattainment areas, and conformance with the requirements of the FCAA, 42 USC, §§7410, 7502(a)(2), and 7511a(d) and (f).

The proposed amendments would require a wide variety of stationary sources of $NO_x$ emissions in HGA 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; ICI boilers; duct burners used in turbine exhaust ducts; process heaters and furnaces; stationary internal combustion engines; fluid catalytic cracking units (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; and BIF units.

The proposed amendments do not specify a particular control technology to achieve the emission limits and there are a variety of control technologies or combinations of control technologies which may be used to comply, depending on the specific circumstances of each affected source. In addition, the Chapter 101 mass emissions cap and trade program being proposed concurrently in this issue of the *Texas Register* establishes compliance flexibility through a mass emissions cap and trade program, which allows compliance to be established through the use of surplus reductions created from other sources.

There may be individual sources for which the equipment actual control costs are higher than those identified in this cost note. The numbers of sources affected by these rules are approximations which do not include all new sources which have been placed into service after 1997. Because these new sources have been permitted under rules which require the new emissions to be offset from existing sources, the counted number of sources will not vary significantly because of offsetting source shutdowns from obsolete equipment. The commission anticipates costs for units not addressed in this fiscal note would be similar to the overall findings of this analysis. Additionally, the commission has included cost for units affected by the proposed amendments that did not report any emission rate data for 1997. No rate data could indicate the unit has been shut down; however, for the purpose of this note, costs were estimated for these units and included in the overall total.

The proposed emission limit for electric utility boilers is 0.010 lb $NO_x$/MMBtu heat input for gas-fired boilers and auxiliary steam boilers, 0.030 lb $NO_x$/MMBtu heat input for oil- or coal-fired, tangential-fired boilers, and 0.030 lb $NO_x$/MMBtu heat input for oil- or coal-fired, wall-fired boilers. The proposed 93% emission reduction, calculated from the average emissions of the electric utility boilers in the area during the baseline period, is expected to necessitate combustion modifications and SCR on the affected electric utility boilers.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that 25 utility boilers and seven auxiliary boilers in HGA will be affected by the proposed amendments. It is estimated that these boilers will be required to reduce $NO_x$ emissions by 184.26 tpd (67,255 tpy). Capital cost of the utility boiler combustion modifications is estimated at $10/kW for the gas-fired combustion modifications, and $5/kW for the coal-fired modifications. The costs of SCR for the coal and gas-fired utility boilers are 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). It is estimated that the cost of $NO_x$ reduction for the electric utility power boilers will range between approximately $1,000 to $8,000 per ton of $NO_x$ reduced. There are two utility systems affected by the proposed amendments. Total capital cost for the first utility system with 10,069 MW of electric generating capacity is $528 million with an increased annual cost of $88 million. This utility system has a mixture of gas- and coal-fired boilers. The average capital cost to gas-fired boilers in this utility system is $16 million with an average increased annual cost of $2.6 million. The average capital cost for coal-fired boilers in this system is $54 million with an average increased annual cost of $9.2 million. Total capital costs for the second utility system with 532 MW of capacity are $24 million with an increased annual cost of $5 million. The average capital cost for boilers in the smaller utility system is $12 million with an average increased annual cost of $2.3 million.

The proposed emission limits for gas-fired ICI boilers are 0.010 lb $NO_x$ per MMBtu heat input for boilers with a maximum rated capacity equal to or greater than 100 MMBtu/hr; 0.015 lb $NO_x$ per MMBtu heat input for 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 boilers with a maximum rated capacity less 40 MMBtu/hr. The proposed 92% $NO_x$ emission reduction from ICI boilers is expected to necessitate SCR and combustion modifications.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that 235 gas-fired ICI boilers with a maximum rated capacity less 40 MMBtu/hr in HGA will be affected by the proposed amendments. The commission estimates that these boilers will be required to reduce $NO_x$ emissions by 0.99 tpd (361 tpy) through the use of combustion modifications. Total capital costs for the combustion modifications are estimated at $3,100 per MMBtu/hr and the annual costs are estimated at $600 per MMBtu/hr. These cost estimates were derived from cost models on page E-23 of EPA's *Alternative Control Techniques Document -- $NO_x$ Emissions from Industrial/Commercial/Institutional (ICI) Boilers*.

Total capital costs for ICI gas-fired boilers rated at 40 MMBtu/hr or less in HGA are approximately $8.1 million with an increased annual cost of $1.6 million. The average capital costs for boilers in this category are approximately $41,000 with an average increased annual cost of $8,300. Cost effectiveness for the proposed emission reductions from the affected boilers in this category is approximately $4,500 per ton of $NO_x$ reduced.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that 90 gas-fired ICI boilers with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr in HGA will be affected by the proposed amendments. The commission estimates that these boilers will be required to reduce $NO_x$ emissions by 3.03 tpd (1,106 tpy) through the use of SCR. The costs of SCR for these ICI boilers were estimated from a spreadsheet provided by NESCAUM. Capital costs for SCR on the affected boilers range from $68/kW to $80/kW. Total capital costs for ICI boilers with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr in HGA are approximately $38 million with an increased annual cost of approximately $11 million. The average capital costs for boilers in this category are approximately $467,000 with an average increased annual cost of $135,000. Cost effectiveness for the proposed emission reductions from the affected boilers in this category is approximately $10,000 per ton of $NO_x$ reduced.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that 180 gas-fired ICI boilers with a maximum rated capacity equal to or greater than 100 MMBtu/hr in HGA will be affected by the proposed amendments. The commission estimates that these boilers will be required to reduce $NO_x$ emissions by 53.24 tpd (19,433 tpy) through the use of SCR and combustion modifications. The costs of SCR for these ICI boilers were estimated from the NESCAUM spreadsheet, and combustion modification costs were estimated to be $10/kW. Capital costs for SCR on the affected boilers range from $49/kW to $80/kW. Total capital costs for ICI boilers with a maximum rated capacity equal to or greater than 100 MMBtu/hr in HGA are approximately $354 million with an increased annual cost of approximately $76 million. The average capital cost for boilers in this category is approximately $1.9 million with an average increased annual cost of $421,000. Cost effectiveness for the proposed emission reductions from the affected boilers in this category is approximately $4,000 per ton of $NO_x$ reduced.

The proposed emission limit for coke-fired boilers is 0.057 lb $NO_x$ per MMBtu heat input. The proposed 90% emission reduction is expected to necessitate SCR on the affected coke-fired boilers. Based upon an analysis of the 1997 emission inventory database, it is anticipated that one coke-fired ICI boiler in HGA will be affected by the proposed amendments. The commission estimates that this boiler will be required to reduce $NO_x$ emissions by 10.44 tpd (3,811 tpy) through the use of SCR. The costs of SCR for this ICI boiler were estimated from a spreadsheet provided by NESCAUM. Capital costs for SCR on the affected boiler are estimated to be $85/kW. Total capital costs for this coke-fired boiler are approximately $15 million with an increased annual cost of approximately $2.8 million. Cost effectiveness for the proposed emission reductions from this boiler is approximately $728 per ton of $NO_x$ reduced.

The proposed emission limit for wood fuel-fired boilers is 0.020 lb $NO_x$ per MMBtu heat input. The proposed 90% emission reduction is expected to necessitate SCR on the affected wood-fired boilers.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that three wood-fired ICI boilers in HGA will be affected by the proposed amendments. The commission estimates that these boilers will be required to reduce $NO_x$ emissions by 0.91 tpd (332 tpy) through the use of SCR and combustion modifications. The smallest of the three wood-fired boilers is a four MMBtu/hr unit. There are no cost estimates available for SCR installed on units of this size. Based on the NESCAUM spreadsheet, the overall capital costs would exceed $100/kW to install SCR on this unit; therefore, the owner or operator of this unit may decide to install combustion modifications and purchase allowances in order to meet required emission limits. The commission estimates the combustion modifications would cost approximately $31/kW. This estimate was derived from costs associated with a 17 MMBtu/hr watertube gas-fired boiler equipped with LNB and FGR which is listed in EPA's *Alternative Control Techniques Document -- $NO_x$ Emissions from Industrial/Commercial/Institutional (ICI) Boilers*. The costs of SCR for the two remaining wood-fired ICI boilers were estimated from a spreadsheet provided by NESCAUM. Capital costs for SCR on the two remaining boilers are approximately $55/kW and $71/kW. Total capital costs for the three wood-fired ICI boilers are approximately $3.5 million with an increased annual cost of approximately $825,000. The average capital cost for the larger two boilers is approximately $1.7 million with an average increased annual cost of $411,000. Cost effectiveness for the proposed emission reductions from the affected boilers in this category is approximately $2,525 per ton of $NO_x$ reduced.

The proposed emission limit for rice hull-fired boilers is 0.089 lb $NO_x$ per MMBtu heat input. The proposed 90% emission reduction is expected to necessitate SCR on the one rice hull-fired boiler contained in the inventory; however, according to agency records this boiler is currently shut down and there are no plans to reactivate this boiler. Consequently, the total annual fiscal impact for rice hull-fired boilers in HGA is assumed to be zero.

The proposed emission limit for oil-fired boilers is 2.0 lb $NO_x$ per 1,000 gallons of oil burned. The proposed 90% emission reduction is expected to necessitate SCR on the affected oil-fired boilers. Based upon an analysis of the 1997 emission inventory database, it is anticipated that three oil-fired ICI boilers will be affected by the proposed amendments. The commission estimates that these boilers will be required to reduce $NO_x$ emissions by 0.13 tpd (47 tpy) through the use of SCR and combustion modifications. Two of the units are low capacity three MMBtu/hr and eight MMBtu/hr boilers. There are no cost estimates available for SCR installed on units of this size. Based on the NESCAUM spreadsheet, the overall capital costs would exceed $90/kW to install SCR on these units; therefore, the owner or operator of these units may decide to install combustion modifications and purchase allowances in order to meet required emission limits. The commission estimates the combustion modifications would cost approximately $31/kW. This estimate was derived from costs associated with a 17 MMBtu/hr watertube gas-fired boiler equipped with LNB and FGR which is listed in EPA's *Alternative Control Techniques Document -- $NO_x$ Emissions from Industrial/Commercial/Institutional (ICI) Boilers*. The costs of SCR on the remaining boilers were estimated from spreadsheets provided by NESCAUM. Capital costs for SCR on the third oil-fired boiler are approximately $72/kW. Total capital costs for affected oil-fired ICI boilers in HGA is approximately $472,000 with an increased annual cost of approximately $135,000. Cost effectiveness for the proposed emission reductions from the affected boilers in this category is approximately $2,900 per ton of $NO_x$ reduced.

The commission estimates the total capital costs for the 513 identified ICI boilers affected by the proposed amendments are approximately $419 million with an annualized cost of $95 million. The overall estimated cost effectiveness for the proposed emission reductions for ICI boilers is approximately $3,800 per ton of $NO_x$ reduced.

The proposed emission limit for fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents) is ten ppmv $NO_x$ (at 0.0% $O_2$, dry basis). The proposed 90% emission reduction is expected to necessitate SCR on the affected fluid catalytic cracking units (FCCUs).

Based upon an analysis of the 1997 emission inventory database, it is anticipated that 14 FCCUs at nine refineries in HGA will be affected by the proposed amendments. The commission estimates that these units will be required to reduce $NO_x$ emissions by 13.44 tpd (4,906 tpy) through the use of SCR. The costs of SCR for these FCCUs were estimated from a spreadsheet provided by NESCAUM. Capital costs for SCR on the affected FCCUs range from $46/kW to $60/kW. Total capital costs for affected FCCUs in HGA are approximately $38.5 million with an increased annual cost of approximately $8.6 million. The average capital costs for units in this category are approximately $2.7 million with an average increased annual cost of $616,000. Cost effectiveness for the proposed emission reductions from the affected FCCUs is approximately $1,800 per ton of $NO_x$ reduced.

The proposed emission limit for pulping liquor recovery furnaces is 0.050 lb $NO_x$ per MMBtu heat input. The proposed 64% $NO_x$ emission reduction is expected to necessitate SNCR on the affected pulping liquor recovery furnaces.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that three pulping liquor recovery furnaces at two pulp mills in HGA will be affected by the proposed amendments. It is estimated that these units will be required to reduce $NO_x$ emissions by 1.09 tpd (398 tpy). Using the total annual cost estimates for SNCR for several types of wood-fired boilers in EPA's *Alternative Control Techniques Document -- $NO_x$ Emissions from Industrial/Commercial/Institutional (ICI) Boilers*, it is estimated that the cost effectiveness will range from approximately $2,000 to $4,500 per ton of $NO_x$ reduced. The total annual fiscal impact for pulping liquor recovery furnaces in HGA is approximately $850,000 to $1.7 million per year.

The proposed emission limits for kilns are 0.66 lb $NO_x$ per ton of CaO for lime kilns and 0.76 lb $NO_x$ per ton of product for lightweight aggregate kilns. The proposed 39% $NO_x$ emission reduction from the kiln category is expected to necessitate combustion controls (such as LNB, or mid-kiln firing and staged combustion) on the affected kilns.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that two lime kilns at two pulp mills and three lightweight aggregate kilns at one lightweight aggregate plant in HGA will be affected by the proposed amendments. It is estimated that these units will be required to reduce $NO_x$ emissions by 0.30 tpd (110 tpy). Based on vendor quotes, installations of staged combustion technology would cost approximately $225,000 per kiln, with estimated annual operating costs of $10,000. Total capital costs for affected kilns in HGA are approximately $1.1 million with an increased annual cost of $125,000. Cost effectiveness for the proposed emission reductions from affected kilns is approximately $1,141 per ton of $NO_x$ reduced.

The proposed emission limits for heat treating and reheat furnaces are 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. The proposed 35% $NO_x$ emission reduction from the steel furnace category is expected to necessitate combustion controls (such as LNB) on the affected furnaces.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that two heat treating furnaces and seven reheat furnaces at one steel processing plant in HGA will be affected by the proposed amendments. It is estimated that these units will be required to reduce $NO_x$ emissions by 0.39 tpd (142 tpy). Annual costs for combustion controls on these units was derived from Tables 7 and 8 on page 85 of the State and Territorial Air Pollution Program Administrators (STAPPA)/Association of Local Air Pollution Control Officials (ALAPCO) document titled *Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options*. Based on the source, annualized costs for the installation of LNB on the affected heat treat furnaces would be approximately $70,000 and $35,000 for the reheat furnaces. The estimated total increased annual costs for affected furnaces are $385,000. Cost effectiveness for the proposed emission reductions from affected furnaces is approximately $2,705 per ton of $NO_x$ reduction.

The 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.

The proposed emission limit for incinerators is a 90% reduction from 1997 ozone season daily $NO_x$ emissions. The proposed 61% $NO_x$ emission reduction from this emission category is expected to necessitate SCR on the affected incinerators.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that 23 incinerators at 16 refineries, chemical plants, and hazardous waste disposal operations in HGA will be affected by the proposed amendments. It is estimated that these units will be required to reduce $NO_x$ emissions by 3.62 tpd (1,321 tpy). The costs of SCR for these incinerators were estimated from a spreadsheet provided by NESCAUM. Capital costs for SCR on the affected incinerators are estimated to range from $49/kW to $72/kW. Total capital costs for these incinerators are approximately $28 million with an increased annual cost of approximately $6.3 million. The average capital cost for units in this category is approximately $1.2 million with an average increased annual cost of $272,000. Cost effectiveness for the proposed emission reductions from affected incinerators is approximately $4,800 per ton of $NO_x$ reduced.

The proposed emission limit for BIF units is 0.015 lb $NO_x$ per MMBtu heat input. The proposed 81% emission reduction is expected to necessitate SCR on the affected BIF units. The proposed emission limit reflects the installation of post-combustion controls, but not combustion controls, because combustion controls potentially could affect the VOC destruction efficiency when these units are burning waste-derived fuel. At the very least, installation of combustion controls potentially could trigger the requirements for a relatively costly trial burn.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that 41 BIF units at 15 refineries and chemical plants in HGA will be affected by the proposed amendments. It is estimated that these units will be required to reduce $NO_x$ emissions by 9.95 tpd (3,632 tpy). The costs of SCR for these units was estimated from the NESCAUM spreadsheet for units with a capacity greater than 40 MMBtu/hr. The cost for SCR on a 50 MMBtu/hr gas-fired boiler, as documented in the STAPPA/ALAPCO document titled *Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options*, was used for units with a capacity less than 40 MMBtu/hr. Capital costs for SCR installed on BIF units less than 40 MMBtu/hr are estimated to be $6,420 per MMBtu/hr with an annual cost of $1,510 per MMBtu/hr. Capital costs for the larger units would range from $49/kW to $65/kW. Total capital costs affected BIF units in HGA are approximately $45 million with an increased annual cost of approximately $10.7 million. The average capital costs for units in this category are approximately $1.1 million with an average increased annual cost of $256,000. Cost effectiveness for the proposed emission reductions from affected BIF units is approximately $3,000 per ton of $NO_x$ reduced.

The proposed emission limits for gas-fired process heaters are 0.010 lb $NO_x$ per MMBtu heat input for units with a maximum rated capacity equal to or greater than 100 MMBtu/hr; 0.015 lb $NO_x$ per MMBtu heat input for units 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 units with a maximum rated capacity less 40 MMBtu/hr. The proposed 88% $NO_x$ emission reduction is expected to necessitate SCR on many affected process heaters and combustion controls on smaller affected process heaters.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that 726 process heaters with a maximum rated capacity less 40 MMBtu/hr in HGA will be affected by the proposed amendments. The commission estimates that these process heaters will be required to reduce $NO_x$ emissions by 4.33 tpd (1,580 tpy) through the use of combustion modifications such as LNB. Based on cost estimates found on page 49, Table 4 in the STAPPA/ALAPCO document titled *Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options*, the commission estimates that the capital costs to install LNB on these process heaters are approximately $3,280 per MMBtu/hr with an annualized cost of approximately $560 per MMBtu/hr. The total capital costs for process heaters with a maximum rated capacity less than 40 MMBtu/hr are approximately $22.3 million with an increased annual cost of approximately $4 million. The average capital cost for units in this category is approximately $32,000 with an average increased annual cost of $5,700. The cost effectiveness for the proposed emission reductions from affected process heaters in this category is approximately $2,510 per ton of $NO_x$ reduced.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that 216 process heaters with a maximum rated capacity greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, in HGA will be affected by the proposed amendments. The commission estimates that these process heaters will be required to reduce $NO_x$ emissions by 12.84 tpd (4,686 tpy) through the use of SCR and combustion modifications . The costs of SCR for these incinerators were estimated from a spreadsheet provided by NESCAUM. Capital costs for SCR on the affected incinerators are estimated to range from $68/kW to $80/kW. Combustion modifications are estimated to cost $28/kW based on cost estimates found on page 49, Table 4 in the STAPPA/ALAPCO document titled *Controlling Nitrogen*

*Oxides Under the Clean Air Act: A Menu of Options*. The total capital costs for process heaters with a maximum rated capacity greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, are approximately $95 million with an increased annual cost of approximately $27 million. The average capital cost for units in this category is approximately $429,000 with an average increased annual cost of $120,000. The cost effectiveness for the proposed emission reductions from affected process heaters in this category is approximately $5,700 per ton of $NO_x$ reduced.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that 424 process heaters with a maximum rated capacity greater than or equal to 100 MMBtu/hr in HGA will be affected by the proposed amendments. The commission estimates that these process heaters will be required to reduce $NO_x$ emissions by 79.35 tpd (28,963 tpy) through the use of SCR and combustion modifications. The costs of SCR for these process heaters were estimated from a spreadsheet provided by NESCAUM. Capital costs for SCR on the affected process heaters are estimated to range from $68/kW to $80/kW. Combustion modifications are estimated to cost $17/kW based on cost estimates found on page 49, Table 4 in the STAPPA/ALAPCO document titled *Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options*. The total capital costs for process heaters with a maximum rated capacity greater than or equal to 100 MMBtu/hr are approximately $596 million with an increased annual cost of approximately $137 million. The average capital cost for units in this category is approximately $1.4 million with an average increased annual cost of $330,000. The cost effectiveness for the proposed emission reductions from affected process heaters in this category is approximately $4,700 per ton of $NO_x$ reduced.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that one oil-fired process heater in HGA will be affected by the proposed amendments. The commission estimates that this process heater will be required to reduce $NO_x$ emissions by 0.04 tpd (15 tpy) through the use of SCR and combustion modifications. Based on cost estimates found on page 50, Table 5 in the STAPPA/ALAPCO document titled *Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options*, the commission estimates SCR cost effectiveness will be approximately $2,300 per ton. The cost effectiveness for LNB is approximately $1,300 per ton. The total increased annual cost for this process heater is approximately $54,000.

The commission estimates that the total capital costs for the 1,367 process heaters affected by the proposed amendments are approximately $713 million with an increased annual cost of $168 million. The overall estimated cost effectiveness for the proposed emission reductions from affected process heaters is approximately $4,800 per ton of $NO_x$ reduced.

The proposed emission limits for gas-fired stationary reciprocating internal combustion engines are: 0.17 g $NO_x$/hp-hr at sites with reciprocating gas-fired engine compressors totaling 3,000 hp or more in 1997 or later; 0.50 g $NO_x$/hp-hr at sites with gas-fired compressors totaling less than 3,000 hp in 1997 or later; and 0.50 g $NO_x$/hp-hr for dual-fuel, reciprocating engines.

The emission inventory indicates 38 sites in 1997 had gas-fired compressor engines totaling more than 3,000 hp. These locations include sixteen upstream gas plants or compressor stations, nine gas transmission or gas storage stations, seven chemical plants, four oil refineries, and two oil terminals.

The proposed limit of 0.17 g $NO_x$/hp-hr at large compressor sites is expected to necessitate replacement with electric motors. The limit is approximately equal to the projected emission rate from electric generating facilities after the addition of Attainment Demonstration SIP $NO_x$ controls. Therefore, either adding emission controls to the engines to meet the limit or converting the site to electric drive would produce similar $NO_x$ reductions. The 3,000 hp or greater site compression threshold is intended to: maximize emission reductions by reducing 90% of the gas compressor engine $NO_x$ according to the more stringent emission limit; include sites with reasonable access to existing transmission lines; exclude smaller sites which are more likely to be located at greater distances from transmission lines; and avoid new transmission line costs to sites with small electric loads.

Since 1997, two of the 38 sites have been converted to electric drive compressors. The estimated costs of conversion to electric drive for the remaining sites are based on cost for one of these sites, documented in an application for property tax abatement for the pollution control project, filed with the commission in April, 2000. The total capital cost of $32.5 million for 42,500 hp of new electric compressors equates to $714/hp. This does not include the cost of upgraded electric transmission lines to the site, which cost approximately $700,000 per mile. The distance of new transmission lines necessary to deliver the appropriate electrical power to gas plants and compressor stations is estimated to average three miles. Operating cost savings for the project with cost information were estimated to include a reduction of eight full time positions to maintain 24,000 hp of existing gas-fired compressor engines and the value of emission credits from the shutdown of the engines. Energy costs were estimated to remain in balance, in part based on the ability to obtain wholesale electric rates. For this analysis, the annual operating costs will be assumed to remain in balance between energy costs and maintenance and emission credit savings.

An analysis of the inventory indicates about 118 gas-fired engines located at sites with less than 3,000 hp of compressor engines would be subject to the 0.5 g $NO_x$/hp-hr limit. Of these, 12 engines reported emissions less than 0.5 g $NO_x$/hp-hr in 1997. Of the remainder, there appear to be 87 rich-burn engines and 31 lean burn engines.

The proposed limit of 0.50 g $NO_x$/hp-hr for gas-fired engines at sites with gas-fired compressors totaling less than 3,000 hp in 1997 or later is expected to be achieved with a combination of technologies. For rich-burn engines, the existing RACT limit of 2.0 g $NO_x$/hp-hr has been met through application of non-selective catalytic reduction (NSCR) to many engines rated more than 150 hp. Many of these rich-burn engines are currently achieving 0.50 g $NO_x$/hp-hr with NSCR. An additional catalyst module will be necessary for some of the rich burn engines to ensure compliance with the proposed limit. The total annualized cost of an additional catalyst module is estimated at $15/hp, based on vendor information. For lean-burn engines, the anticipated controls necessary to comply are a combination of combustion modifications to limit emissions to 5.0 g $NO_x$/hp-hr or less, and then SCR to achieve the 0.50 g $NO_x$/hp-hr emission limit. Combustion modifications to reduce emissions to 5.0 g $NO_x$/hp-hr or less include low emission retrofits, high energy ignition, and high pressure fuel injection. Low emission combustion costs for this cost note were based on total capital ($315,000 + ($350*HP) and annualized ($71,300 + ($74.8*HP) cost equations on pages 6-33 and 6-38 of EPA's ACT document, *Alternative Control Techniques Document – $NO_x$ Emissions from Stationary Reciprocating*

*Internal Combustion Engines*, (EPA-453/R-93-032). Based on an analysis of the emission inventory data, the SCR reductions necessary range from 50% for engines with a current baseline of 1.0 g $NO_x$/hp-hr, to 90% for engines which must initially reduce to 5.0 g $NO_x$/hp-hr with combustion modification. The cost of SCR for gas-fired engines is estimated from the total capital ($310,000 + ($72.7*HP) and annualized ($140,000 + ($40*HP) cost equations on page 6-56 of the ACT document.

An analysis of the inventory indicates one dual-fuel electric generator engine would be subject to the 0.5 g $NO_x$/hp-hr limit. This engine appears to currently operate at approximately 5.0 g $NO_x$/hp-hr, such that a 92% efficient SCR would enable it to comply with the proposed limit without additional combustion modifications. The higher removal efficiency appears feasible because the literature contains examples of SCR operating at 92% removal efficiency on stationary diesel and gas-fired engines. The cost of SCR for the dual-fuel engine is estimated from the total capital ($187,000 + ($98*HP) and annualized ($37,300 + $16.3*HP) cost equations on page 6-60 of the ACT document.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that approximately 450 stationary gas-fired reciprocating internal combustion engines in HGA will be affected by the proposed amendments. It is estimated that these engines will be required to reduce $NO_x$ emissions by 78.50 tpd. Based on the referenced sources, it is estimated that the cost will range from approximately $50 to $25,000 per ton of $NO_x$ reduced. The total capital cost for gas-fired reciprocating internal combustion engines in HGA is approximately $441 million with an increased annual cost of approximately $63 million per year.

The proposed emission limits for stationary gas turbines and duct burners used in turbine exhaust ducts is 0.015 lb $NO_x$ per MMBtu heat input (about four ppmv, dry at 15% $O_2$). The proposed 92% $NO_x$ emission reduction is expected to necessitate SCR on affected stationary gas turbines and duct burners. In addition, for those gas turbines which are currently not achieving the RACT limit of 42 ppmv, it is anticipated that combustion modifications such as water or steam injection will also be necessary to achieve the proposed emission limits.

Based upon an analysis of the 1997 emission inventory database, it is anticipated that approximately 189 stationary gas turbines and any associated duct burners in HGA will be affected by the proposed amendments. Total annualized costs are estimated from cost tables 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). It is estimated that these units will be required to reduce $NO_x$ emissions by 141 tpd (51,465 tpy). It is estimated that the cost effective will range from approximately $1,000 to $25,000 per ton of $NO_x$ reduced, except for peaking gas turbines. For peaking gas turbines, it is estimated that the cost effectiveness will range from approximately $13,000 to $75,000 per ton of $NO_x$ reduced. Using the ACT document, the total capital costs for turbines in this category are approximately $403 million with an increased annual cost of $130 million per year.

Based on an analysis of the 1997 emission inventory database, the proposed continuous monitoring of boilers and heaters with heat input rated greater than or equal to 100 MMBtu/hr will require approximately an additional 300 boilers, heaters, and furnaces to install and operate $NO_x$ CEMS or PEMS. The commission estimates the initial cost of a CEMS which monitors $NO_x$, oxygen, and flow to be approximately $137,400 to $179,600, with total annual costs of $64,800 to $66,000, based upon *U.S. EPA's Continuous Emission Monitoring System Cost Model, Version 3.0*. Based on these figures, the total cost for the additional $NO_x$ CEMS or PEMS would be $54 million with an increased annual cost of approximately $20 million. It should be noted that this cost model provides the initial costs (including capital and installation costs) and annual costs (operating costs) for a single CEMS installed to monitor emissions from one source at a plant. In the cost model's user manual, the EPA notes that the cost model is not intended for use in estimating the costs for multiple CEMS to monitor multiple sources at a plant. Simply multiplying the number of CEMS by the model's result will overestimate the total cost since some of the costs are not repeated with the addition of a second CEMS or more.

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. In addition, the proposed 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 proposed 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, graph, 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.

Based on an analysis of the emissions inventory, there are approximately 600 industrial boilers, process heaters and furnaces with rated heat input between two MMBtu/hr and 40 MMBtu/hr, which would require fuel use meters to track annual emissions. Installed costs for fuel flow meters are estimated to range from $3,500 to $10,000 per meter. The total increased annual cost for additional fuel meters in HGA is approximately $0.5 million.

In addition to the direct emission control costs identified in this note, there are additional costs associated with lost production for those sources which will not be able to accommodate the installation of the control equipment during normal equipment outage periods. In some cases, there may be costs of lost production due to additional process outages related to emission control equipment start up.

The total capital cost for all known affected sources in HGA is approximately $2.7 billion with an increased annual cost of approximately $597 million.

SMALL BUSINESS AND MICRO-BUSINESS ASSESSMENT

The commission has been unable to identify any small or micro-businesses which would be affected by the proposed amendments. The majority of sites affected by the proposed amendments are large petrochemical and industrial businesses. If there are affected small or micro-businesses, the estimated capital and annualized cost for installing and operating the control technology used for the various types of units in this fiscal note would appear to be a reasonable cost estimate for small or micro-businesses. The proposed amendments would require a wide variety of stationary sources of $NO_x$ emissions in HGA 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; ICI boilers; duct burners used in turbine exhaust ducts; process heaters and furnaces;

stationary internal combustion engines; 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; and BIF units. The proposed amendments do not specify a particular control technology to achieve the emission limits and there may be other control technologies or combinations of control technologies which may be used to comply. In addition, the Chapter 101 mass emissions cap and trade program being proposed concurrently in this issue of the *Texas Register* establishes compliance flexibility through a mass emissions cap and trade program, which allows compliance to be established through the use of surplus reductions created from other sources.

DRAFT REGULATORY IMPACT ANALYSIS DETERMINATION

The commission has reviewed the proposed 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 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 internal combustion engines; fluid catalytic cracking units (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; 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 proposed amendments are intended to protect the environment, the commission believes they may adversely affect in a material way all sources in the HGA ozone nonattainment area with a potential to emit $NO_x$ in amounts greater than or equal to ten tpy, as well as boilers, heaters, and stationary engines with a potential to emit $NO_x$ in amounts less than ten tpy. These sources comprise sectors of the economy (including petroleum refineries, petrochemical plants, and electric generating plants) in a sector of the state. This is based on the analysis provided elsewhere in this preamble, including the discussion in the Public Benefit and Costs section.

The 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 proposed 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 implement $NO_x$ RACT for 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 proposed amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

The proposed amendments do not meet any of the four applicability criteria of a "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.

As discussed earlier, the proposed amendments implement 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 proposed changes comply with the requirements of the Texas Health and Safety Code, Texas Clean Air Act (TCAA) §§382.011, 382.012, 382.016, 382.017, 382.018, and 382.051(d). Therefore, these proposed amendments do not exceed a standard set by federal law, exceed an express requirement of state law, exceed a requirement of a delegation agreement, nor are adopted solely under the general powers of the agency.

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

TAKINGS IMPACT ASSESSMENT

The commission has prepared a takings impact assessment for these sections under Texas Government Code, §2007.043. The following is a summary of that assessment. The specific purposes of these amendments are: to develop a new attainment demonstration SIP for the ozone NAAQS for HGA; and to implement $NO_x$ RACT required by 42 USC, §7511a(f), for certain source categories. If adopted, certain sources located in HGA will be required to install new emission control equipment, and implement new operating, reporting, and recordkeeping requirements. Installation of the necessary control equipment could conceivably place a burden on private, real property. Also, 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. In addition, these amendments to fulfill an obligation mandated by federal law. The proposed amendments will implement requirements of 42 USC, §7410 and §7511a(f). 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 ambient $NO_x$ and ozone levels in HGA. Attainment of the ozone standard will eventually require substantial $NO_x$ reductions. Any $NO_x$ reductions resulting from the current rulemaking are no greater than what the best 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.

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 31 TAC §505.11(b)(2) and 30 TAC §281.45(a)(3), 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 primary CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations at 40 CFR to protect and enhance air quality in the coastal area. The rules, which require additional reductions of air emissions in HGA, will result in reductions of ambient $NO_x$ and ozone concentrations. The proposed rules are consistent with the applicable CMP policy because they are consistent with Title 40. Title 40, Part 51, sets out requirements for states to prepare, adopt, and submit implementation plans for the attainment of the NAAQS. The adopted rules would be submitted to the EPA under these requirements. Interested persons may submit comments on the consistency of the proposed rules with the CMP during the public comment period.

ANNOUNCEMENT OF HEARINGS

The commission will hold public hearings on this proposal at the following times and locations: September 18, 2000, 10:00 a.m., Lone Star Convention Center, 9055 Airport Road (FM 1484), Conroe; September 18, 2000, 7:00 p.m., Lake Jackson Civic Center, 333 Highway 332 East, Lake Jackson; September 19, 2000, 10:00 a.m. and 7:00 p.m., George Brown Convention Center, 1001 Avenida de Las Americas, Houston; September 20, 2000, 9:00 a.m., VFW Hall, 6202 George Bush Drive, Katy; September 20, 2000, 6:00 p.m., East Harris County Community Center, 7340 Spencer, Pasadena; September 21, 2000, 10:00 a.m., Southeast Texas Regional Airport Media Room, 6000 Airline Drive, Beaumont; September 21, 2000, 2:00 p.m., Amarillo City Commission Chambers, City Hall, 509 East 7th Avenue, Amarillo; September 21, 2000, 6:00 p.m., Charles T. Doyle Convention Center, 21st Street at Phoenix Lane, Texas City; September 22, 2000, 10:00 a.m., Dayton High School, 2nd Floor Lecture Room, 3200 North Cleveland Street, Dayton; September 22, 2000, 11:00 a.m., El Paso City Council Chambers, 2 Civic Center Plaza, 2nd Floor, El Paso; September 22, 2000, 2:00 p.m., North Central Texas Council of Governments, 2nd Floor Board Room, 616 Six Flags Drive, Suite 200, Arlington; and September 25, 2000, 10:00 a.m., Texas Natural Resource Conservation

Commission, 12100 North I-35, Building E, Room 201S, Austin. The hearings are structured for the receipt of oral or written comments by interested persons. Registration will begin one hour prior to each hearing. Individuals may present oral statements when called upon in order of registration. A four-minute time limit will be established at each hearing to assure that enough time is allowed for every interested person to speak. Open discussion will not occur during each hearing; however, agency staff members will be available to discuss the proposal one hour before each hearing, and will answer questions before and after each hearing.

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

SUBMITTAL OF COMMENTS

Written comments may be submitted to Heather Evans, Office of Environmental Policy, Analysis, and Assessment, MC 206, P.O. Box 13087, Austin, Texas 78711-3087; faxed to (512) 239-4808; or emailed to *siprules@tnrcc.state.tx.us*. All comments should reference Rule Log Number 2000-011H-117-AI. Comments must be received by 5:00 p.m., September 25, 2000. For further information or questions concerning this proposal, please contact Randy Hamilton at (512) 239-1512 or Eddie Mack at (512) 239-1488.

STATUTORY AUTHORITY

The amendment is proposed 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; §382.016, 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; 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.

The proposed amendment implements the Texas Health and Safety Code, TCAA, §§382.011, 382.012, 382.016, 382.017, and 382.051(d).

## SUBCHAPTER A: DEFINITIONS

### §117.10

**§117.10. Definitions.**

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

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

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

(7) - (10) (No change.)

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

(A) All boilers, [steam generators,] 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, [steam generators,] 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) [(12)] **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) [(13)] **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) [(14)] **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.

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

(17) [(16)] **Industrial boiler [or steam generator]** - 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.

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

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

(20) [(19)] **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.

(21) [(20)] **Low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit** - An industrial, [A] commercial, or institutional [, or industrial] 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.

(22) [(21)] **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.

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

(24) [(23)] **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.

(25) [(24)] **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.

(26) [(25)] **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.

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

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

(29) [(28)] **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.

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

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

(32) [(31)] **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.

(33) [(32)] **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.

(34) [(33)] **Predictive emissions [emission] 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.

(35) [(34)] **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 [or steam generators] as defined in this section.

(36) [(35)] **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.

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

(38) [(37)] **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.

(39) [(38)] **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.

(40) [(39)] **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.

(41) [(40)] **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.

(42) [(41)] **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.

(43) [(42)] **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.

(44) [(43)] **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 [Any] boiler, [steam generator,] 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.

(45) [(44)] **Utility boiler [or steam generator]** - 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.

(46) [(45)] **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 [EXISTING] 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 proposed 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; §382.016, 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; 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.

The proposed amendments and new sections implement the Texas Health and Safety Code, TCAA, §§382.011, 382.012, 382.016, 382.017, and 382.051(d).

**§117.101. Applicability.**

(a) The provisions of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas) shall apply to the following units used in an electric power generating system, as defined in §117.10(12)(A) [§117.10(11)(A)] of this title (relating to Definitions), owned or operated by a municipality or a Public Utility Commission of Texas (PUC) regulated utility, or any of their successors, regardless of whether the successor is a municipality or is regulated by the PUC, located within the Beaumont/Port Arthur, Houston/Galveston, or Dallas/Fort Worth ozone nonattainment areas:

(1) (No change.)

[(2) steam generators;]

(2) [(3)] auxiliary steam boilers; and

(3) [(4)] stationary gas turbines.

(b) (No change.)

**§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) [this division (relating to Utility Electric Generation in Ozone Nonattainment Areas)], except as may be specified in §117.113(h), (i), and (j) [§117.113(i)] of this title [(relating to Continuous Demonstration of Compliance)], include the following:

(1) (No change.)

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

(3) (No change.)

(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) [(b)] Emergency fuel oil firing.

(1) The fuel oil firing emission limitations [limitation] of §§117.105(c), 117.106(a), (b), and (c)(1)(B), 117.107(b), and 117.108 [§117.105(c) or §117.107(b)] of this title [(relating to Emissions Specifications in Ozone Nonattainment Areas and Alternative System-wide Emission Specifications)] 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 the distributed generation of electricity, 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 [,steam generator,] 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 [or steam generator], $NO_x$ 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 [, steam generator,] 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 [, steam generator,] 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.)

(e) - (g) (No change.)

(h) No person shall allow the discharge into the atmosphere from any utility boiler [, steam generator,] 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), based on:

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

(i) - (j) (No change.)

(k) For purposes of this subchapter, the following shall apply:

(1) (No change.)

(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.

**§117.106. Emission Specifications for Attainment Demonstrations.**

(a) Beaumont/Port Arthur [Beaumont Port/Arthur]. The owner or operator of each [No person shall allow the discharge into the atmosphere from any] utility boiler located in the Beaumont/Port Arthur ozone nonattainment area [,] shall ensure that emissions of nitrogen oxides ($NO_x$) do not exceed [in excess of] 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 [No person shall allow the discharge into the atmosphere from any] utility boiler located in the Dallas/Fort Worth (DFW) ozone nonattainment area [,] shall ensure that emissions of $NO_x$ do not exceed [in excess of]: 0.033 lb/MMBtu [pound per million Btu] heat input from boilers which are part of a large DFW system, and [emissions of $NO_x$ in excess of] 0.06 lb/MMBtu [pound per million Btu] 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 emissions banking and trading 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); and

(3) stationary gas turbines, 0.015.

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

(1) carbon monoxide (CO) emissions in excess of 400 ppmv [parts per million by volume (ppmv)] at 3.0% $O_2$ [oxygen], dry (or alternatively, 0.30 lb/MMBtu [pound per MMBtu] heat input), based on:

(A) a one-hour average for units not equipped with continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (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 10 ppmv, based on a block one-hour averaging period.

(e) [(d)] Compliance flexibility.

(1) In the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, an [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 [(relating to System Cap)]; 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 [utility boiler] within an electric power generating system, as defined in §117.10 (12)(A) [§117.10 (11)(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 [utility boiler] in the electric power generating system

$N$ = the total number of EGFs [utility boilers] in the emission cap

$H_i$ = (A) For the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, the [The] average of the daily heat input for each EGF [utility boiler] 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 [utility boilers] exempt from the 40 Code of Federal Regulations (CFR) Part 75 [(40 CFR Part 75)] monitoring requirements, if the heat input data corresponding to the system highest 30-day period (as determined for EGFs [utility boilers] 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, the average of the daily heat input for each EGF in the emission cap, in million Btu per day, as certified to the executive director, for the system highest 30-day period in the nine months of July, August, and September 1997, 1998, and 1999. For 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.

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

(B) For EGFs [utility boilers] 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<u>.</u> [:]

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

(3) Each <u>EGF</u> [utility boiler] 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 <u>EGF</u> [utility boiler] in the system cap shall be used to demonstrate continuous compliance with the system cap.

(e) For each operating <u>EGF</u> [utility boiler], 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 <u>Code of Federal Regulations</u> (CFR) 75, use the missing data procedures specified in 40 CFR 75, Subpart D (Missing Data Substitution Procedures); <u>or</u>

(B) (No change.)

(2) (No change.)

(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) (No change.)

(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 [conducted in accordance with §117.111(e) of this title (relating to Initial Demonstration of Compliance)].

(f) The owner or operator of any EGF [utility boiler] subject to a system cap shall maintain daily records indicating the $NO_x$ emissions and fuel usage from each EGF [utility boiler] and summations of total $NO_x$ emissions and fuel usage for all EGFs [utility boilers] 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 [Record keeping], and Reporting Requirements).

(g) The owner or operator of any EGF [utility boiler] 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 [utility boiler] 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 [A utility boiler] 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) (No change.)

(k) For the purposes of determining compliance with the source cap emission limit, the contribution of each affected EGF [utility boiler] 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 [be tested] as follows.

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

(3) Testing shall be performed in accordance with the schedules specified in §117.510 of this title (relating to Compliance Schedule for [For] Utility Electric Generation in Ozone Nonattainment Areas).

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

(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) -(2) (No change.)

(3) For EGFs [utility boilers] 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 [utility boilers] 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) - (5) (No change.)

**§117.113. Continuous Demonstration of Compliance.**

(a) - (e) (No change.)

(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) (No change.)

(2) Monitor diluent, either oxygen or carbon dioxide:

(A) using a CEMS

(i) (No change.)

(ii) with a similar alternative method approved by the executive director and EPA [the United States Environmental Protection Agency]; or

(B) (No change.)

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

(g) Stationary gas [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) - (B) (No change.)

(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) [(1)] any unit subject to the emission specifications of this division;

(B) [(2)] 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) [(3)] 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) (No change.)

(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 [this division]. 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), and (d) - (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).

(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) 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 units [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 (and, in the Houston/Galveston ozone nonattainment area, auxiliary boilers and stationary gas turbines) within the electric generating system, either:

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

(C) §117.570 of this title (relating to Trading); or

(D) Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program);

(2) the methods of control of $NO_x$ emissions for each utility boiler (and, in the Houston/Galveston ozone nonattainment area, auxiliary boilers and stationary gas turbines) [unit];

(3) the emissions measured by testing required in §117.111 or §117.114 of this title (relating to Initial Demonstration of Compliance; and Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration);

(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 or §117.114 of this title which is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any utility boiler (and, in the Houston/Galveston ozone nonattainment area, auxiliary boilers and stationary gas turbines) with a claimed exemption from the emission specification of §117.106 of this title.

(b) (No change.)

(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 [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 [Exemptions from Rules and Regulations]), 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 [the Unites States Environmental Protection Agency (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) - (c) (No change.)

(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) (No change.)

(2) - (5) (No change.)

(e) (No change.)

**§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 or ammonia limits of §117.106(d) [§117.106(c)] of this title (relating to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.105 of this title for that unit. The executive director:

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

(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 [United States Environmental Protection Agency] in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas).

**DIVISION 2: UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS**

**§117.138**

STATUTORY AUTHORITY

The amendment is proposed 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; §382.016, 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; 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.

The proposed amendment implements the Texas Health and Safety Code, TCAA, §§382.011, 382.012, 382.016, 382.017, and 382.051(d).

**§117.138. System Cap.**

(a) (No change.)

(b) Each unit within an electric power generating system, as defined in §117.10(12)(B) [§117.10(11)(B)] of this title (relating to Definitions), that would otherwise be subject to the $NO_x$ emission limits of §117.135 of this title must be included in the system cap.

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

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

**§§117.201, 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 proposed 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; §382.016, 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; 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.

The proposed amendments and new sections implement the Texas Health and Safety Code, TCAA, §§382.011, 382.012, 382.016, 382.017, and 382.051(d).

**§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 [, or industrial] boilers and process heaters [with a maximum rated capacity of 40 million Btu per hour or greater];

(2) stationary gas turbines; [with a megawatt (MW) rating of 1.0 MW or greater; and]

(3) stationary internal combustion engines; [which are:]

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

[(B) located in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment area with a horsepower rating of 300 hp or greater.]

(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 (including fume abaters).

**§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) [and §117.213(a) and (i) of this title (relating to Continuous Demonstration of Compliance)], 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);

[(3) any electric utility power generating boiler;]

(4) flares, incinerators, fume abaters, 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 (including fume abaters) 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; [and]

(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; and [.]

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

(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 the distributed generation of electricity, combustion sources registered under that permit are exempt from this chapter.

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

(a) (No change.)

(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) - (5) (No change.)

(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 [emission monitors] (CEMS) or predictive emissions monitoring system [emission monitors] (PEMS) under §117.213 of this title (relating to Continuous Demonstration of Compliance), the emission limits shall apply as:

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

(8) (No change.)

(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. <u>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.</u>

(d) - (g) (No change.)

(h) Units exempted from the emissions specifications of this section include the following:

(1) any <u>industrial,</u> commercial, <u>or</u> institutional [, or industrial] boiler or process heater with a maximum rated capacity less than 100 MMBtu/hr;

(2) (No change.)

(3) boilers and industrial furnaces which were regulated as existing facilities by the <u>EPA</u> [United States Environmental Protection Agency] 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 [supplemental waste heat recovery units] 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; [and]

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

(10) stationary gas turbines and engines, which are demonstrated to operate less than 850 hours per year, based on a rolling 12-month average; and

(11) 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.

**§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) [(d)] and (g) [(e)] of this section:

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

(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) [(d)] and (g) [(e)] of this section:

(1) (No change.)

(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 [g 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), 10 ppmv $NO_x$ at 0.0% $O_2$, dry basis;

(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), 0.015 lb $NO_x$ per MMBtu;

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

(5) wood fuel-fired boilers, 0.020 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 engines at sites with a total hp rating of 3,000 hp or more in 1997 or later, 0.17 g $NO_x$/hp-hr, except as specified in subparagraph (C) of this paragraph;

(B) gas-fired engines at sites with a total hp rating of less than 3,000 hp in 1997 or later, 0.50 g $NO_x$/hp-hr; and

(C) dual-fuel engines:

(i) with initial start of operation on or before December 31, 2000, 0.50 g $NO_x$/hp-hr; and.

(ii) with initial start of operation after December 31, 2000, 0.17 g $NO_x$/hp-hr;

(10) stationary gas turbines, 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, 0.050 lb $NO_x$ per MMBtu;

(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) 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; and

(16) incinerators (including fume abaters), a 90% reduction from the emission factor used to calculate the 1997 ozone season daily $NO_x$ emissions.

(d) [(c)] $NO_x$ averaging time.

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

(A) [(1)] if the unit is operated with a $NO_x$ continuous emissions monitoring system [emission monitors] (CEMS) or predictive emissions monitoring system [emission monitors] (PEMS) under §117.213 of this title (relating to Continuous Demonstration of Compliance), either as:

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

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

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

(B) [(2)] 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 [paragraph (1)(C) of this subsection].

(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) [(d)] Related emissions. No person shall allow the discharge into the atmosphere from any boiler or process heater subject to $NO_x$ emission specifications in subsection (a), (b), or (c) [(b)] of this section, emissions in excess of the following, except as provided in §117.221 of this title (relating to Alternative Case Specific Specifications):

(1) carbon monoxide (CO), 400 ppmv at 3.0% $O_2$, dry basis;

(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, 10 [5] ppmv on a block one-hour averaging period.

(f) [(e)] Compliance flexibility.

(1) In the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, an [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 (relating to Alternative Case Specific Specifications) 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) [(f)] 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 [, or industrial] 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.

**§117.207. Alternative Plant-wide Emission Specifications.**

(a) (No change.)

(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 continuous emissions monitoring system [emission monitors] (CEMS) or predictive emissions monitoring system [emission monitors]

(PEMS) in accordance with §117.213 of this title (relating to Continuous Demonstration of Compliance), the emission limits shall apply in:

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

(2) - (4) (No change.)

(c) - (e) (No change.)

(f) Units exempted from emission specifications in accordance with §117.205(h) and §117.206(g) [§117.206(e)] 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) [§117.206(e)] 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) - (3) (No change.)

(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 [following] 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 [, steam generators,] 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 [the United States Environmental Protection Agency (EPA)] at 40 Code of Federal Regulations (CFR) Part 266, Subpart H | the appropriate emission limitation in §117.205(b) of this title |

(g) - (i) (No change.)

**§117.208. Operating Requirements.**

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

(d) All units subject to the emission limitations of §§117.205, 117.206 [(relating to Emission Specifications for Attainment Demonstrations)], 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) - (3) (No change.)

(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) - (7) (No change.)

**§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.

(b) Each EGF that would otherwise be 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

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

$R_i$ = (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, 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; and

(F) stationary, reciprocating, dual-fuel internal combustion engines:

(i) with initial start of operation on or before December 31, 2000, 0.50 g $NO_x$/hp-hr; and.

(ii) with initial start of operation after December 31, 2000, 0.17 g $NO_x$/hp-hr.

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

Figure: 30 TAC §117.210(c)(2)

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

Where:

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

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

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

(d) 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) - (4) (No change.)

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

(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) - (4) (No change.)

(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 [the United States Environmental Protection Agency (EPA)]; or

(6) (No change.)

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

**§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) [(A)] if individually rated more than 40 million British thermal units (Btu) per hour (MMBtu/hr):

(I) [(i)] boilers;

(II) [(ii)] process heaters;

(III) [(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) [(iv)] gas turbine supplemental-fired waste heat recovery units;

(ii) [(B)] stationary, reciprocating internal combustion engines not exempt by §117.203(a)(6) or (8) [§117.203(6) or (8)] of this title (relating to Exemptions), or §117.205(h)(10) or (11) of this title;

(iii) [(C)] 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) [(D)] 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;

(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) pulping liquor recovery furnaces;

(ix) lime kilns;

(x) lightweight aggregate kilns;

(xi) heat treating furnaces;

(xii) reheat furnaces;

(xiii) magnesium chloride fluidized bed dryers; and

(xiv) 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 [emission] 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) (No change.)

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

(A) units listed in §117.205(h)(3) - (5) and (8) - (11) of this title [(relating to Emission Specifications];

(B) - (C) (No change.)

(3) (No change.)

(c) $NO_x$ monitors.

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

(A) - (D) (No change.)

(E) units which use a chemical reagent for reduction of $NO_x$; [and]

(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 [this division] 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) - (11) of this title [(relating to Emission Specifications for Reasonably Available Control Technology)]; and

(B) (No change.)

(d) - (g) (No change.)

(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) - (2) (No change.)

(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) [§117.203(6)(B)] of this title shall record the operating time with an elapsed run time meter.

(j) (No change.)

(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 [this division]. 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) - (3) (No change.)

**§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), and (e) - (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. 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).

(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) 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.

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

(a) The owner or operator of units listed in §117.206 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) (No change.)

(B) Section 117.210 of this title (relating to System Cap);

(C) [(B)] Section 117.223 of this title (relating to Source Cap); and as applicable, [or]

(D) [(C)] Section 117.570 of this title (relating to Trading); or

(E) Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program);

(2) - (5) (No change.)

(b) (No change.)

(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 [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 [Exemptions from Rules and Regulations]), 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) (No change.)

(2) verbal notification of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) relative accuracy test audit (RATA) [performance evaluation] 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 <u>appropriate regional office</u> [executive director] 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 <u>RATA</u> [relative accuracy test audit (RATA)] conducted under §117.213 of this title:

(1) (No change.)

(2) not later than the compliance schedule specified in §117.520 of this title (relating to Compliance Schedule <u>for</u> [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. 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 (relating to Emission Specifications for Reasonably Available Control Technology (RACT)).

(B) (No change.)

(2) - (5) (No change.)

(e) (No change.)

(f) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain written or electronic records of the data specified in this subsection. Such records shall be kept for a period of at least five years and shall be made available upon request by authorized representatives of the executive director, EPA, or local air pollution control agencies having jurisdiction. The records shall include:

(1) for each unit subject to §117.213(a) of this title, records of annual fuel usage;

(2) [(1)] for [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; 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) [(2)] 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) [§117.208(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) [(3)] 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) [(4)] 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) [(5)] for units claimed exempt from the emission specifications of this division 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) [(6)] Records of carbon monoxide measurements specified in §117.213(d)(2) of this title; [.]

(8) [(7)] 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) [(8)] 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 or ammonia limits of §117.206(e) [§117.206(d)] of this title (relating [Relating] to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.205 of this title for that unit. The executive director:

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

(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 [the United States Environmental Protection Agency] in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to 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 proposed 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; §382.016, 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; 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.

The proposed new sections implement the Texas Health and Safety Code, TCAA, §§382.011, 382.012, 382.016, 382.017, and 382.051(d).

**§117.471. Applicability.**

This division (relating to Boilers, Process Heaters, and Stationary Engines 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; and

(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.

(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 (relating to Monitoring, Recordkeeping, and Reporting Requirements):

(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 the distributed generation of electricity, 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); and

(2) from stationary, reciprocating internal combustion engines, 0.50 gram per horsepower-hour (g/hp-hr).

**§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 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.

**§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 paragraph (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.

**SUBCHAPTER E: ADMINISTRATIVE PROVISIONS**

**§§117.510, 117.520, and 117.534**

STATUTORY AUTHORITY

The amendments and new section are proposed 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; §382.016, 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; 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.

The proposed amendments and new section implement the Texas Health and Safety Code, TCAA, §§382.011, 382.012, 382.016, 382.017, and 382.051(d).

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

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

(1) (No change.)

(2) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.106(a) of this title (relating to Emission Specifications for Attainment Demonstrations) as soon as practicable, but no later than:

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

(i) 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 [the effective date of §117.106(a) of this title]; 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) (No change.)

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

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

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

(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) - (B) (No change.)

(C) Submit to the executive director:

(i) (No change.)

(ii) for units operating with CEMS or PEMS in accordance with §117.113 of this title, the results of:

(I) - (II) (No change.)

(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; [and]

(D) - (E) (No change.)

(2) Emission specifications for attainment demonstration.

(A) The owner or operator shall comply with the requirements of §117.106(b) of this title [(relating to Emission Specifications for Attainment Demonstrations)] as soon as practicable, but no later than:

(i) [(A)] 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) [(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 [the effective date of §117.106(b) of this title]; or

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

(-b-) [(II)] Section 117.570 (relating to Trading);

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

(I) [(i)] identification of enforceable emission limits which satisfy clause (i) [subparagraph (A)] of this subparagraph [paragraph];

(II) [(ii)] the information specified in §117.116 of this title [(relating to Final Control Plans Procedures for Attainment Demonstration Emission Specifications)] to comply with clause (i) [subparagraph (A)] of this subparagraph [paragraph]; and

(III) [(iii)] any other revisions to the source's final control plan as a result of complying with clause (i) [subparagraph (A)] of this subparagraph [paragraph];

(iii) [(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 clause (i) [subparagraph (A)] of this subparagraph [paragraph];

(iv) [(D)] May 1, 2005, comply with §117.106(b) of this title;

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

(I) [(i)] a demonstration of compliance with §117.106(b) of this title;

(II) [(ii)] the information specified in §117.116 of this title; and

(III) [(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) [(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(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. [November 15, 1999 (final compliance date). The owner or operator shall:]

(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) [(1)] conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.113 of this title according to the following schedules:

(i) [(A)] 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) [(B)] for equipment and software not required under 40 CFR 75, no later than November 15, 1999;

(B) [(2)] install all $NO_x$ abatement equipment and implement all $NO_x$ control techniques no later than November 15, 1999;

(C) [(3)] submit to the executive director:

(i) [(A)] for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.111 of this title; by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(ii) [(B)] for units operating with CEMS or PEMS in accordance with §117.113 of this title, the results of:

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

(II) [(ii)] the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title;

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

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

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

(D) [(4)] 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) [(5)] 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. The owner or operator shall comply with the requirements of §117.106(c) of this title as soon as practicable, but no later than:

(A) December 31, 2001, install all totalizing fuel flow meters, $NO_x$ monitors, and carbon monoxide (CO) monitors required by §117.113 of this title;

(B) December 31, 2002, demonstrate that at least one-third of the $NO_x$ emission reductions required by §117.106(c) of this title have been accomplished, as measured by the total amount of emissions reductions required to comply with §117.106(c) of this title using §117.108 of this title;

(C) December 31, 2003, demonstrate that at least two-thirds of the $NO_x$ emission reductions required by §117.106(c) of this title have been accomplished, as measured by the total amount of emissions reductions required to comply with §117.106(c) of this title using §117.108 of this title;

(D) December 31, 2002, submit to the executive director:

(i) identification of enforceable emission limits which satisfy subparagraph (B) of this paragraph;

(ii) the information specified in §117.116 of this title to comply with subparagraph (B) of this paragraph; and

(iii) any other revisions to the source's final control plan as a result of complying with subparagraph (B) of this paragraph;

(E) February 28, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title;

(F) December 31, 2004, demonstrate that all $NO_x$ emission reductions required by §117.106(c) of this title have been accomplished, as measured by the total amount of emissions reductions required to comply with §117.106(c) of this title using §117.108 of this title;

(G) February 28, 2005, submit a revised final control plan which contains:

(i) a demonstration of compliance with §117.106(c) 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(c) of this title; and

(H) the appropriate dates specified in Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) for the requirements of that program.

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

(a) The owner or operator of each industrial, commercial, and institutional [, and industrial] source in the Beaumont/Port Arthur ozone nonattainment area shall comply with the requirements of Subchapter B, Division 3 of this chapter (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) as soon as practicable, but no later than the dates specified in this subsection.

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

(3) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.206(a) of this title (relating to Emission Specifications for Attainment Demonstrations) as soon as practicable, but no later than

(A) May 1, 2003, demonstrate that at least two-thirds of the $NO_x$ emission reductions required by §117.206(a) of this title have been accomplished, as measured either by

(i) 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 [the effective date of §117.206(a) of this title]; or

(ii) (No change.)

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

(i) - (iv) (No change.)

(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) - (D) (No change.)

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

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

(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 [, and industrial] 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) - (2) (No change.)

(c) The owner or operator of each industrial, commercial, and institutional [, and industrial] 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. [November 15, 1999 (final compliance date). The owner or operator shall:]

(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) [(1)] 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) [(A)] 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) [(B)] 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) [(C)] 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) [(2)] install all $NO_x$ abatement equipment and implement all $NO_x$ control techniques no later than November 15, 1999;

(C) [(3)] submit to the executive director:

(i) [(A)] for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title; by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

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

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

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

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

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

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

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

(iv) [(D)] 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. The owner or operator shall comply with the requirements of §117.206(c) of this title as soon as practicable, but no later than:

(A) December 31, 2001, install all totalizing fuel flow meters, $NO_x$ monitors, and carbon monoxide (CO) monitors required by §117.213 of this title;

(B) December 31, 2002, demonstrate that at least one-third of the $NO_x$ emission reductions required by §117.206(c) of this title have been accomplished, as measured by:

(i) for electric generating facilities (EGFs), the total amount of emissions reductions required to comply with §117.206(c) of this title using §117.210 of this title (relating to System Cap); and

(ii) for non-EGFs, the total amount of emissions reductions required to comply with §117.206(c) of this title using Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program);

(C) December 31, 2003, demonstrate that at least two-thirds of the $NO_x$ emission reductions required by §117.206(c) of this title have been accomplished, as measured by:

(i) for EGFs, the total amount of emissions reductions required to comply with §117.206(c) of this title using §117.210 of this title; and

(ii) for non-EGFs, the total amount of emissions reductions required to comply with §117.206(c) of this title using Chapter 101, Subchapter H, Division 3 of this title;

(D) December 31, 2002, submit to the executive director:

(i) identification of enforceable emission limits which satisfy subparagraph (B) of this paragraph;

(ii) 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;

(iii) for units newly operating with CEMS or PEMS to comply with the monitoring requirements of §117.213(c) 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 to comply with subparagraph (B) of this paragraph; and

(v) any other revisions to the source's final control plan as a result of complying with subparagraph (B) of this paragraph;

(E) February 28, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title;

(F) December 31, 2004, demonstrate that all $NO_x$ emission reductions required by §117.206(c) of this title have been accomplished, as measured by:

(i) for EGFs, the total amount of emissions reductions required to comply with §117.206(c) of this title using §117.210 of this title; and

(ii) for non-EGFs, the total amount of emissions reductions required to comply with §117.206(c) of this title using Chapter 101, Subchapter H, Division 3 of this title;

(G) February 28, 2005, submit a revised final control plan which contains:

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

(H) the appropriate dates specified in Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) for the requirements of 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 all totalizing fuel flow meters and begin keeping records of fuel usage no later than December 31, 2001; and

(B) comply with all other requirements of Subchapter D, Division 2 of this chapter in accordance with the schedule specified in Chapter 101, Subchapter H, Division 3 of this title.

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

(A) install all totalizing fuel flow meters and begin keeping records of fuel usage no later than December 31, 2001; and

(B) comply with all other requirements of Subchapter D, Division 2 of this chapter as soon as practicable, but no later than December 31, 2002.