The Texas Natural Resource Conservation Commission (TNRCC or commission) proposes amendments to §117.10, concerning Definitions; §§117.105 - 117.108, 117.113 - 117.116, 117.119, and 117.121, concerning Utility Electric Generation in Ozone Nonattainment Areas; §§117.131, 117.135, 117.138, 117.141, 117.143, and 117.149, concerning Utility Electric Generation in East and Central Texas; §§117.203, 117.205 - 117.207, 117.213 - 117.216, 117.219, 117.221, and 117.223, concerning Industrial, Commercial, and Institutional Sources in Ozone Nonattainment Areas; §§117.301, 117.309, 117.311, 117.313, 117.319, and 117.321, concerning Adipic Acid Production; §§117.401, 117.409, 117.411, 117.413, 117.419, and 117.421, concerning Nitric Acid Manufacturing - Ozone Nonattainment Areas; §§117.463, 117.465, and 117.467, concerning Water Heaters, Small Boilers, and Process Heaters; §§117.473, 117.475, 117.478, and 117.479, concerning Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources; and §§117.510, 117.512, 117.520, and 117.534, concerning Administrative Provisions; new §117.151 and §117.481, concerning Alternate Case Specific Specifications; the repeal of §117.104, concerning Gas-Fired Steam Generation, §117.540, concerning Phased Reasonably Available Control Technology (RACT), and §117.560, concerning Recission; and corresponding revisions to the state implementation plan (SIP). The commission is excluding the proposed new §§117.135(2) and 117.475(i), concerning Emission Specifications, 117.151, and 117.481 from the SIP in order to simplify the approval process for alternative carbon monoxide (CO) or ammonia emission specifications, thereby eliminating the need for case specific SIP revisions by the EPA to complete the approval of an alternate CO or ammonia limit.

The proposed amendments to Chapter 117, concerning Control of Air Pollution from Nitrogen Compounds, and revisions to the SIP would improve implementation of the existing Chapter 117 by correcting typographical errors, updating cross-references, clarifying ambiguous language, adding flexibility, deleting obsolete language, and amending requirements to achieve the intended nitrogen oxides (NO_x) emission reductions of the program.

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

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE PROPOSED RULES

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

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base case episodes, adopted rules to achieve a 9% rate-of-progress (ROP) reduction in VOCs, 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 nitrogen oxides (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 EPA modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data-gathering exercise known as the Coastal Oxidant Assessment for Southeast Texas (COAST) study. The commission believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

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

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

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

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

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

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

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

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

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

In January 2001, the BCCA Appeal Group (BCCA-AG) and several regulated companies challenged the December 2000 HGA SIP and some of the associated rules. Specifically, the BCCA-AG challenged the 90% NO_x reduction requirement from stationary sources in the HGA area. In May 2001, the parties agreed to a stay in the case, and Judge Margaret Cooper, Travis County District Court, signed a Consent Order, effective June 8, 2001, requiring the commission to perform an independent, thorough analysis of the causes of rapid ozone formation events and identify potential mitigating measures not yet identified in the HGA attainment demonstration, according to the milestones and procedures in Exhibit C (Scientific Evaluation) of the Consent Order.

On September 26, 2001, the commission adopted a revision to the December 2000 HGA SIP. This revision included changes to several previously adopted rules, removal of the construction equipment operating restriction and the accelerated purchase requirement for Tier 2/3 heavy duty equipment, and adjustments to the ROP and NO_x gap to account for mathematical inconsistencies. The September 2001 SIP also laid out the mid-course review process by detailing how the state will fulfill its commitment to obtain the additional emission reductions necessary to demonstrate attainment of the one-hour ozone standard in HGA by 2007. Chapter 7 of the September 2001 SIP described the options for reducing NO_x emissions and the anticipated results from improvements to science between 2001 and the 2004 mid-course review.

In compliance with the Consent Order, the commission conducted a scientific evaluation based in large part on aircraft data collected by the Texas 2000 Air Quality Study (TexAQS). The TexAQS, a comprehensive research project conducted in August and September 2000 involving more than 40 research organizations and over 200 scientists, studied ground-level ozone air pollution in the HGA and east Texas regions. The study revealed that while NO_x emissions from industrial sources were generally correctly accounted for, industrial VOC emissions were likely significantly understated in earlier emissions inventories. The study also showed that surface monitors were insufficient in capturing the phenomenon of ozone plumes downwind of industrial facilities. On four separate days, ozone levels exceeding 125 parts per billion (ppb) were recorded by aircraft instruments that were missed by surface monitoring equipment.

Preliminary results from the scientific evaluation of TexAQS data were summarized in a memorandum, dated February 28, 2002, which is available at
ftp://ftp.tceq.state.tx.us/pub/AirQuality/AirQualityPlanningAssessment/Modeling/HGAQSE/Reports_2

002Feb/TNRCC/exsummary_20020228.pdf. Analysis showed that plumes stemming from HGA's industrial areas produce ozone very rapidly due to the collocation of large NO_x and VOC emissions from industrial facilities. Initial efforts were focused on the most remarkable findings - that a select number of highly reactive VOCs - ethylene, propylene, and 1, 3 butadiene contributed to very large portions of reactivity observed airborne samples, and were previously underreported in the emissions inventory used in the December 2000 HGA SIP. As scientists completed more detailed analyses, other reactive VOCs, including isoprene, butenes, formaldehyde, acetaldehyde, toluene, pentenes, trimethylbenzenes, xylenes, and ethyltoluenes may be found to possibly contribute to ozone production in HGA. Other scientists also may have indicated that large amounts of less reactive VOC emissions have contributed to ozone production in HGA. At this time, commission staff has not been able to analyze the role of these additional VOCs in ozone production in HGA, but plans to conduct that analysis prior to the mid-course review SIP revision. This study concluded that controls on upsets and routine industrial VOC emissions are necessary to address some of the elevated ozone levels observed in HGA.

In order to address recent scientific findings and to fulfill the BCCA-AG Consent Order, the commission is proposing revisions to the industrial source control requirements, one of the control strategies within the existing federally approved SIP. This revision contains new rules to reduce emissions of highly-reactive VOCs from four key industrial sources: fugitives, flares, process vents, and cooling towers. Current inventory indicates that approximately 48% of the highly reactive VOCs come from fugitives, 30% from flares, 8% from vents, and 7% from cooling towers. More details about these controls are included in the Section by Section Discussion of this preamble.

Technical support documentation accompanying this revision contains early results from on-going analysis examining whether reductions in emissions of highly-reactive VOCs can replace the last 10% of industrial NO_x controls, while maintaining the integrity of the SIP by ensuring that the air quality specified in the approved December 2000 HGA SIP continues to be met. Several detailed analyses provide some directional support for the premise that it may be possible to achieve the same level of air quality benefits with reductions in industrial olefin emissions, combined with an 80% reduction in NO_x emissions from industrial sources, as would be realized with a 90% reduction in industrial NO_x emissions. This preliminary indication is based on new analysis of the September 1993 episode using advanced meteorological models combined with a top-down adjustment to the point source olefin emissions; modeling of a new 2000 episode, also using a top-down adjustment to point source olefin emissions; and results from a sophisticated box model, which was set up to replicate actual air samples taken during the study.

The September 8 - 11, 1993 episode was modeled using three meteorological methods: Systems Applications International Mesoscale Model (SAIMM), Mesoscale Model 5 (MM5), and Regional Atmospheric Modeling System (RAMS). Sensitivity analysis indicated that it may be possible to substitute the last 10% of point source NO_x reductions if olefin emissions in the model are six times as large as in the original modeling demonstration. With the scaled-up olefin emissions in the model, the required olefin reduction from industrial sources varied from approximately 27% to 90%.

The August 25 - September 1, 2000 episode was also modeled, incorporating numerous improvements in science made since the December 2000 HGA SIP. Key among the improvements was the use of the state-of-the-science MM5 meteorological model, an upgraded emissions inventory, and several other enhancements. Interpolation of results for August 25, 29, and 31, 2000 indicated that the last 10% of NO_x reductions can potentially be replaced with industrial source olefin reductions. The required olefin reductions from industrial sources varied from approximately 8% to 27%. Note that the 2000 episode is under development, and these reduction percentages may change.

A complex box model simulation was set up to replicate the chemical composition in actual air samples taken from the Houston Ship Channel area during the TexAQS. This box model used the National Center for Atmospheric Research (NCAR) Master Mechanism (Madronich), which includes 800 species of hydrocarbons and 2200 reactions, and is recognized as one of the most complete chemistry models available to scientists studying air quality problems. Results from this model also indicated that the last 10% of NO_x reductions might be able to be replaced with industrial olefin reductions.

Analysis also demonstrated that reductions of highly-reactive VOCs from industrial sources ranging from 4% to 54%, combined with an 85% NO_x industrial reduction, could potentially achieve the same levels of air quality improvement as a 90% NO_x reduction.

The proposed rules target highly-reactive VOCs while maintaining the integrity of the SIP. Analysis to date shows that limiting highly-reactive VOCs to 100 tons per day (tpd) in conjunction with an 80% reduction in NO_x may lead to air quality benefits equivalent to that resulting from a 90% point source NO_x reduction requirement. The commission recognizes that these results are only preliminary and that further work will be needed to increase confidence in them. As such, the proposed highly-reactive VOC rules are performance-based, emphasizing monitoring, recordkeeping, reporting, and enforcement rather than immediately establishing firm emissions reductions targets in tpd. The proposed rules are intended to facilitate the collection of emission inventory data by industry over the next few months, to be used to evaluate whether emissions specifications from preliminary results are appropriate. This data will also help the commission understand the role of the other reactive VOCs (isoprene, butenes, formaldehyde, acetaldehyde, toluene, pentenes, trimethylbenzenes, xylenes, ethyltoluenes) found to contribute to ozone production in the HGA area. The role of large amounts of less reactive VOC emissions in ozone production will also be investigated through the summer of 2002. Over the next few months, the commission plans to perform new modeling, develop a conceptual description of the ozone problem, and identify additional improvements to supplement the conclusions made to date based on initial results. It is anticipated that by the December 2002 adoption, there will be additional technical support in order to allow the commission to make a final determination, which may lead to adjustments in emission specifications.

As discussed in Chapter 7 of the HGA SIP, this revision is another phase in the process of continued analysis and review of the science. The data collected as a result of these revisions will further assist the commission as it develops its full reassessment of the attainment demonstration at the mid-course review.

The proposed rules both address recent scientific findings and fulfill the BCCA-AG Consent Order, by proposing to implement measures to mitigate the rapid ozone formation in the HGA area according to the milestones established in Exhibit C of the Consent Order. As noted earlier, these rules are based on preliminary data and therefore focus on accelerated monitoring, recordkeeping, reporting, and enforcement in order to build the science. By the adoption date, the commission intends to have better data and greater confidence in the exact emissions reductions requirements required to control highly reactive VOCs while maintaining the integrity of the SIP.

SECTION BY SECTION DISCUSSION

Formatting, punctuation, and other non-substantive corrections are made throughout the rulemaking as necessary. These corrections include the deletion of unnecessary section title references. These non-substantive corrections will not be discussed further.

The proposed changes to §117.10, concerning Definitions, revise the definitions of “boiler” and “industrial boiler” in order to clarify that these definitions include the heating of water, rather than only the production of steam. In the October 12, 2001 issue of the *Texas Register* (26 TexReg 8141), the commission published notice that the definition of “boiler” inadvertently does not include large water heaters rated at greater than 2.0 million British thermal units per hour (MMBtu/hr) because the definition refers to producing steam. These units may be as large as approximately 5.0 MMBtu/hr and are no different to control than the corresponding-sized boiler. The proposed revisions to the definitions of “boiler” and “industrial boiler” are consistent with the notice in the October 12, 2001 issue of the *Texas Register* that the commission anticipated initiating rulemaking after October 15, 2001 to add a reference to heating of water. The proposed changes are necessary to ensure that large water heaters in HGA which are rated at greater than 2.0 MMBtu/hr (and therefore excluded from the rules for water heaters and small boilers under §§117.460 - 117.469) are subject to the emission specifications for attainment demonstration (ESADs) of §117.206(c).

The proposed changes to §117.10 also add a definition of “duct burner” which is consistent with the use of this term in Chapter 117. Subsequent definitions are proposed to be renumbered to accommodate the new definition.

In addition, the proposed changes to the definition of “electric generating facility (EGF)” replace the term “facility” with the more accurate term “unit.” The proposed changes to §117.10 further revise the definition of “electric power generating system” by adding a reference to electric generating facility (EGF) accounts in the renumbered §117.10(14)(A) and (B). This change is necessary because auxiliary boilers are intended to be included (as evidenced by their inclusion in §117.101, concerning Applicability, and the emission specifications established for them in §117.105, concerning Emission Specifications for Reasonably Available Control Technology (RACT), and §117.106, concerning Emission Specifications for Attainment Demonstrations). As currently written, §117.10(13)(A) and (B) (which are being renumbered as §117.10(14)(A) and (B)) could be misinterpreted to mean that auxiliary boilers are not included because they do not, by themselves, generate electricity for compensation.

The proposed changes to §117.10 also update the reference to the Electric Reliability Council of Texas, Inc. (ERCOT) Protocols in the definition of "emergency situation" to reflect the most recent version of the ERCOT Protocols. In addition, the proposed changes to §117.10 revise the definition of “heat input” by abbreviating carbon monoxide, and revise the definition of “megawatt (MW) rating” to clarify that this definition is based on the unit's output.

The proposed changes to §117.10 also revise the definition of “predictive emissions monitoring system (PEMS)” to delete a reference to use of a graph to convert process or control device operating parameter measurements into results in units of the applicable emission limitation. This change is necessary because PEMS operate such that a conversion equation or computer program automatically performs the calculations, and the reference to “graph” in the current definition inaccurately implies that these calculations are not necessarily made automatically.

In addition, the proposed changes to §117.10 revise the definition of “stationary internal combustion engine” by adding a clarification that “nonroad engines, as defined in 40 Code of Federal Regulations (CFR) §89.2, are not considered stationary for the purposes of Chapter 117. The proposed changes to §117.10 also revise the definition of “unit” to delete an extra “or” in §117.10(5)(A).

Finally, the proposed changes to §117.10 revise the definition of “utility boiler” to clarify that gas turbines, including associated duct burners and unfired waste heat boilers, are not considered to be utility boilers. This revision is necessary because the current definition of “utility boiler” could be interpreted to include these units, which is not the intent of the definition.

Section 117.104, concerning Gas-Fired Steam Generation, is proposed for repeal because this section has been made obsolete by the passing of the March 31, 2001 RACT final compliance date specified in §117.510(b)(1) for electric utilities in the Dallas/Fort Worth (DFW) ozone nonattainment area. The requirements of §117.104 were initially adopted by the Texas Air Control Board (one of the TNRCC's predecessor agencies) in 1972, but these requirements are no longer applicable after the March 31, 2001 final compliance date.

The proposed changes to §117.105, concerning Emission Specifications for Reasonably Available Control Technology (RACT), abbreviate “pound per million Btu” in §117.105(a) - (c), (g)(1) - (2), and (h). In addition, the proposed changes to §117.105 revise a reference in §117.105(d) from "subsections (a) - (c)" to "subsections (a) and (c)" because subsection (b) does not apply to firing a mixture of natural gas and fuel oil.

The proposed changes to §117.105 also revise §117.105(e) by adding a reference to subsection (d). This change is necessary because this subsection is not intended to apply to any auxiliary steam boiler which is an affected facility as defined by New Source Performance Standards (NSPS) 40 CFR 60, Subparts D, Db, or Dc. In addition, the proposed changes to §117.105 delete a reference to §117.540 in §117.105(k)(2) because §117.540 is proposed for repeal, as described later in this preamble. Finally, the proposed changes to §117.105 replace the phrase “pursuant to” in §117.105(k)(2) with “in accordance with” for consistency with the agency's style guidelines.

The proposed changes to §117.106, concerning Emission Specifications for Attainment Demonstrations, delete the alternate ESADs in §117.106(c)(5)(A) - (C) which were provided by BCCA-AG as part of the Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC. Specifically, in January 2001, BCCA-AG and others filed suit against the commission challenging the December 6, 2000 SIP revision for HGA and five of the ten sets of rules associated with that SIP revision. As part of that lawsuit, the plaintiffs sought a temporary injunction to stay the effectiveness of these five sets of rules and for the commission to withdraw the SIP from EPA consideration. A hearing on this request was held before Judge Margaret Cooper, Travis County District Court, Texas, on May 14 - 18, 2001. Before that hearing was completed, an agreement in principle was reached to settle the lawsuit, and a Consent Order was entered by Judge Cooper which includes certain specific items included in the SIP revision and rules in Chapters 101 and 117 proposed by the commission on May 30, 2001 (see the June 15, 2001 issue of the *Texas Register* (26 TexReg 4380 and 4400, respectively)) and subsequently adopted on September 26, 2001 (see the October 12, 2001 issue of the *Texas Register* (26 TexReg 8110 and 8089, respectively)).

In the December 2000 adoption of the original ESADs to achieve approximately 90% reductions in NO_x point source emissions, the commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of those ESADs. The commission determined that the various controls which can be used to meet the ESADs have a proven performance experience and that the 90% reductions are technically feasible. A detailed explanation of how the commission reached these conclusions is given in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524).

The September 26, 2001 adoption of revisions to Chapter 117 included changes to §117.106 which revised the ESAD in HGA for gas-fired utility boilers from 0.010 pound per million British thermal units (lb/MMBtu) to 0.020 lb/MMBtu in §117.106(c)(1)(A), and revised the ESAD in HGA for coal-fired or oil-fired utility boilers from 0.030 lb/MMBtu to 0.040 lb/MMBtu in §117.106(c)(1)(B). The changes had the effect of reducing the emission reduction requirement for the major HGA electric utility from 93% to 90%, based on its peak 30-day NO_x emissions in 1998. The changes similarly reduced the percentage reduction required of the other Public Utility Commission (PUC)-regulated electric utility in HGA. The justification for these changes is described in detail in the October 12, 2001 issue of the *Texas Register* (26 TexReg 8110).

The commission is proposing to delete the current ESADs in §117.106(c)(1) - (4) and replace them with the alternate ESADs of §117.106(c)(5)(A) - (C) which were provided by BCCA-AG as part of the Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC.

The proposed changes to §117.106 further revise §117.106(d)(2) by specifying standard oxygen (O_2) conditions for ammonia concentration measurements and add flexibility to the ammonia compliance averaging period by allowing a rolling 24-hour average for units which monitor ammonia with a continuous emissions monitoring system (CEMS) or PEMS. The reference conditions of 3.0% O_2 for boilers and 15% O_2 for gas turbines on a dry basis are standard conventions in the air pollution control industry and were inadvertently excluded in previous rulemaking. The lengthier averaging period for units which continuously monitor emissions of ammonia is consistent with existing Chapter 117 flexibility for NO_x and CO monitoring. A lengthier averaging period is easier to comply with than a comparatively shorter one and is an incentive to continuously monitor emissions.

The proposed changes to §117.107, concerning Alternative System-wide Emission Specifications, delete obsolete references to "steam generators" in §117.107(a)(2) and (3), (c), and (d)(1). The proposed changes to §117.107 also delete a reference to "auxiliary steam boiler" in §117.107(d)(1) that conflicts with §117.107(a)(1)(B), which specifically prohibits auxiliary steam boilers from inclusion in the system-wide emission limit.

In addition, the proposed changes to §117.107 add a new §117.107(e) which specifies that after the applicable attainment demonstration SIP compliance date, the alternative plant-wide RACT emission specifications will no longer apply to equipment in HGA for which §117.106(c) has established a more stringent emission specification. This will avoid any potential conflicts of the RACT limits and the more stringent ESADs. For purposes of §117.107(e), the alternative plant-wide RACT emission specifications of §117.107 remain in effect until the emissions allocation for a unit under the HGA mass emissions cap are equal to or less than the allocation that would be calculated using the alternative plant-wide RACT emission specifications of §117.107.

The proposed changes to §117.108, concerning System Cap, revise §117.108(b) to update a reference to the renumbered §117.10(14).

The proposed changes to §117.113, concerning Continuous Demonstration of Compliance, address the relative accuracy requirement of each NO_x monitor. Previously, each NO_x monitor (CEMS or PEMS) in the Beaumont/Port Arthur (BPA), DFW, or HGA ozone nonattainment area was subject to the relative accuracy requirement of 40 CFR 75, Appendix B, Figure 2. That requirement allowed a concentration option (in parts per million by volume (ppmv) and/or lb/MMBtu) for the relative accuracy of any unit classified as a low emitter (<0.200 lb/MMBtu). This proposal removes that previous relative accuracy option and replaces it with a more restrictive option which will provide better confidence in the monitor's ability to make low-level measurements for NO_x. It also levels the RA requirements for utility and industrial, commercial, and institutional (ICI) monitors. Commission staff discussed the current Part 60 expectation and capability with EPA's Emission Measurement Center (EMC) staff. EMC staff stated that the reference method, when implemented with a good tester and good equipment, should be able to provide results within one ppmv of the CEMS. Commission staff believe that the current monitors and procedures may not necessarily provide this capability for low-level measurements. The commission expects EPA to develop new monitor requirements/procedures in the future and temporarily defers a more restrictive relative accuracy option than two ppmv and/or future changes of relative accuracy requirement until such time that commission staff have more experience with the low-level monitor certification and/or EPA recommendations. The commission seeks comments, recommendations, and input in the relative accuracy level required to assure and document compliance with emissions limits of ten ppmv and below.

The proposed changes to §117.113 also revise §117.113(c)(2) and add a new §117.113(c)(3) to address the sharing of CEMS among more than one unit. The existing §117.113(c)(2) was developed for the NO_x RACT rules, with which affected units typically comply by meeting an individually enforceable limit, either directly through §117.105 or through averaging in accordance with §117.107. However, compliance with §117.106(c) and the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, concerning Mass Emissions Cap and Trade Program, in HGA is demonstrated through a limit on total annual tons of NO_x emitted to the atmosphere, such that it would be more effective for the NO_x CEMS requirements to be linked to stacks, rather than individual units. The proposed new §117.113(c)(3) enables the sharing of CEMS in this manner in HGA. The proposed new §117.113(c)(3) also specifies that all bypass stacks shall be monitored in order to quantify emissions directed through the bypass stack. This is necessary because under the mass emissions cap and trade program, all NO_x emissions are considered, including those from startup, shutdown, upset, and maintenance activities at affected units. The proposed new §117.113(c)(3) further specifies that exhaust streams of units which vent to a common stack do not need to be analyzed separately.

In addition, the proposed changes to §117.113 delete two section titles in §117.113(g) and (h)(1) because the titles are included earlier in this section in the proposed changes to §117.113(c)(2) and (3). The proposed changes to §117.113 also abbreviate "megawatt" because this term is abbreviated earlier in this section. Finally, the proposed changes to §117.113 replace the phrase "pursuant to" with "in accordance with" for consistency with the agency's style guidelines.

The proposed changes to §117.114, concerning Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration, add a new §117.114(a)(4) which requires that ammonia monitoring be applied to units which inject urea or ammonia into the exhaust stream for NO_x control. The commission is proposing several options for ammonia slip monitoring in order to provide flexibility and minimize cost. The first option is to calculate the slip with a mass balance, as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of selective catalytic reduction (SCR). Because this option relies on process parameters routinely monitored in SCR systems, it is the least expensive procedure and is commonly specified in new source review (NSR) permits. The permits typically require annual calibration of this method using a stack emission test for ammonia. The commission seeks comments on the usefulness of this stack test calibration based on recent experience. The second option is to monitor ammonia slip more directly by splitting the exhaust sample stream, converting the ammonia to nitric oxide (NO) in one stream with a thermal oxidizer, and measuring the ammonia as the difference between the converted and unconverted samples. This is the slip monitoring approach recommended by the Institute of Clean Air Companies at http://www.icac.com/noxgaswp.pdf. By alternately measuring streams, it may be feasible to monitor ammonia using an already required downstream NO_x analyzer, which would eliminate the cost of a separate analyzer. The third option is to use another method as approved by the executive director. A number of commercial methods of monitoring ammonia slip are described in the EPA's "Ammonia CEMS Background Report," June 14, 1993, available at http://www.epa.gov/ttn/emc/cem.html.

Control of the excess ammonia generation is a part of the science, as well as the economics, of post-combustion controls which utilize urea or ammonia as a reagent, and a competently designed and operated post-combustion control system will minimize excess ammonia generation. Minimizing ammonia slip depends on designing the system such that injected ammonia is properly-mixed and well-distributed and such that the amount of catalyst (in the case of SCR) is sufficient to control both NO_x

and ammonia to the desired levels. Nevertheless, there will be an increase in ammonia emissions due to ammonia slip associated with the use of post-combustion control technologies. It is desirable to minimize ammonia emissions due to the concern that significantly increased ammonia emissions will enhance formation of fine particulate matter of less than 2.5 microns ($PM_{2.5}$). Consequently, monitoring for ammonia emissions is necessary. The proposed changes to §117.114 also renumber the existing §117.114(a)(4) as §117.114(a)(5).

In addition, the proposed changes to §117.114 revise §117.114(c)(2)(C) to clarify that any retesting at a unit not equipped with a CEMS or PEMS establishes a new emission factor to be used to calculate actual emissions from the date of the retesting forward, with the previously determined emission factor used to calculate actual emissions for compliance with the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 until the date of the retesting.

The proposed changes to §117.114 also add a new §117.114(c)(2)(D) which requires that all test reports be submitted to the executive director for review and approval within 60 days after completion of the testing. This is consistent with the existing requirements of Chapter 117 and is necessary to ensure the integrity and accuracy of testing.

The proposed changes to §117.115, concerning Final Control Plan Procedures for Reasonably Available Control Technology, delete an incorrect section title in §117.115(a)(1) and correct the reference to §117.570 in §117.115(a)(2)(D) to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)).

The proposed changes to §117.116, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, correct the reference in §117.116(a)(1)(C) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)).

The proposed changes to §117.116 also add a new §117.116(a)(1)(D) which adds a reference to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3. This reference is necessary to ensure that sources in HGA submit the required information necessary to document compliance (for example, the calculations used to calculate the 30-day average and maximum daily system cap allowable emission rates).

The proposed changes to §117.119, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.119(a) by replacing a reference to 30 TAC §101.11, concerning Demonstrations, with a reference to 30 TAC §101.222, concerning Demonstrations. Section 101.222 was proposed in the April 26, 2002 issue of the *Texas Register* (27 TexReg 3475) and, if adopted, will replace the current §101.11.

The proposed changes to §117.119 also revise §117.119(b)(1) to clarify that verbal notification of the date of any testing conducted under §117.111 must be made at least 15 days prior to such date followed by written notification within 15 days after testing is completed. Likewise, the proposed changes to

§117.119(c) clarify that results of testing conducted under §117.111 must be provided to the TNRCC central and regional offices and any local air pollution control agency having jurisdiction. This revision is necessary to ensure that any retesting conducted under §117.114(c)(2) is subject to the same notification and test result reporting requirements as the initial test.

The proposed changes to §117.121, concerning Alternative Case Specific Specifications, clarify that requests for alternate carbon monoxide (CO) or ammonia limits are evaluated by the Engineering Services Team, Office of Compliance and Enforcement. It should be noted that the paragraphs (§117.106(d) and §117.206(e)) addressing pollutants which may increase as an incidental result of compliance with the NO_x limits, specifically, CO and ammonia, continue to be excluded from the SIP. The proposed changes to §117.121 also change a reference in §117.121(a)(2) from RACT to §117.105 or §117.106. This change is necessary because the ESADs of §117.106 go beyond RACT in some cases.

The proposed changes to §117.131, concerning Applicability, add a new §117.131(b) which specifies that the provisions of §117.134, concerning Gas-Fired Steam Generation, also apply in Palo Pinto County. This is necessary because units in Palo Pinto County are subject to §117.134 (Gas-Fired Steam Generation, initially adopted by the Texas Air Control Board in 1972), but Palo Pinto County is not included in the counties listed in the existing §117.131(4).

In addition, the proposed changes to §117.131 and to §117.135, concerning Emission Specifications, make it clear that duct burners in gas turbine exhaust ducts are included in the applicability of Subchapter B, Division 2, Utility Electric Generation in East and Central Texas. This will ensure that emissions from a duct burner are subject to the same emission specification as the associated gas turbine of which the duct burner is an integral part.

The proposed changes to §117.135 also add a new paragraph (2) which establishes CO and ammonia emission limits of 400 ppmv CO at 3.0% oxygen (O_2), dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units and 0.33 lb/MMBtu heat input for coal-fired units) and ten ppmv ammonia. The new limits are necessary to prevent large increases in ammonia and CO emissions concurrent with the installation of NO_x controls. These limits are consistent with the corresponding limits for CO and ammonia in §117.106, and represent a maximum rate under good engineering practice. Initial testing for these pollutants is already required under §117.141(a)(1) and (2), concerning Initial Demonstration of Compliance. The commission is excluding these related pollutant limits of the proposed §117.135(2) from the SIP in order to simplify the approval process for alternative emission specifications under the proposed new §117.151, concerning Alternative Case Specific Specifications. 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 current §117.135(1) and (2) is renumbered as §117.135(1)(A) and (B) to accommodate the new §117.135(2).

The proposed changes to §117.138, concerning System Cap, revise §117.138(b) to update a reference to the renumbered §117.10(14), add the acronym "PEMS" to §117.138(e)(3), and revise §117.138(e)(3)(B) to update a reference to the renumbered §117.143(e) which is described later in this preamble.

The proposed changes to §117.141 revise the reference in §117.141(a) from Subchapter B, Division 2 to §117.135. This change is necessary to prevent units which are subject to §117.134 (Gas-Fired Steam Generation, initially adopted by the Texas Air Control Board in 1972) but which are not subject to §117.135, from inadvertently being subject to the testing requirements of §117.141. In addition, the proposed changes to §117.141 revise §117.141(d) to correct a typographical error in the abbreviation of "pound per million British thermal units."

The proposed changes to §117.143, concerning Continuous Demonstration of Compliance, revise §117.143(b) to require sampling or monitoring of CO emissions using one of several options. A portable analyzer can be used, reference method testing can be conducted, or a CEMS or PEMS for CO can be installed. As described earlier in this preamble, the proposed new CO limits of §117.135(2) are necessary to prevent large increases in CO emissions concurrent with the installation of NO_x controls. The proposed CO limit is consistent with the corresponding limit for CO in §117.106, and represents a maximum rate under good engineering practice. Initial testing for these pollutants is already required under §117.141(a)(1) and (2). The proposed revisions to §117.143(b) are necessary to ensure that CO emissions remain below the proposed new CO limits of §117.135(2).

In addition, the proposed changes to §117.143 delete the requirements for auxiliary boilers in the existing §117.143(e) because auxiliary boilers do not meet the applicability criteria described in §117.131, and renumber subsequent subsections due to the deletion of subsection (e). The proposed changes to §117.143 also revise the renumbered §117.143(e)(2)(A)(i) to correct a reference to the CEMS requirements of §117.143(c). Finally, the proposed changes to §117.143 revise the renumbered §117.143(g)(3) and (i) to delete the wording "low annual capacity factor" from the reference to the exemption of §117.133, since these exemptions do not use this wording.

The proposed changes to §117.149, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.149(a) by replacing a reference to §101.11 with a reference to §101.222. Section 101.222 was proposed in the April 26, 2002 issue of the *Texas Register* (27 TexReg 3475) and, if adopted, will replace the current §101.11.

The proposed new §117.151 allows alternative emission specifications to be established on a case specific basis for CO and ammonia. The commission is excluding these related pollutant limits from the SIP in order to simplify the approval process for alternative emission specifications. 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 proposed changes to §117.203, concerning Exemptions, revise §117.203(a) to include a reference to §117.219(f)(10) to ensure that the necessary records are maintained to demonstrate compliance with the diesel engine and dual-fuel engine testing and maintenance operating hour restrictions of §117.206(i). The proposed changes to §117.203 also clarify §117.203(a)(1) by adding a reference to §117.205(a)(3), concerning Emission Specifications for Reasonably Available Control Technology (RACT), for functionally identical replacement units. The proposed changes to §117.203 further revise §117.203(a)(2) by changing "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the remainder of this division.

In addition, the proposed changes to §117.203 revise §117.203(a)(4) by adding molten sulfur oxidation furnaces to the list of exemptions. A molten sulfur oxidation furnace produces sulfur dioxide for use in manufacturing sulfuric acid through the oxidation of molten sulfur. This addition is consistent with the existing exemptions for certain units which commingle fuel and process chemicals, such as sulfuric acid regeneration units. The proposed changes to §117.203 also revise §117.203(a)(6) by adding the phrase "stationary internal combustion" to clarify that this exemption is not limited to gas-fired engines.

The proposed changes to §117.205 revise §117.205(a) to specify that emission reduction credits available under §117.570, concerning Use of Emissions Credits for Compliance, may be used to comply with §117.205. The proposed changes to §117.205 also abbreviate pound NO_x per million British thermal units as lb NO_x/MMBtu in §117.205(a)(1)(A) and (2)(A), and §117.205(b)(1)(A) and (7)(A) - (B). In addition, the proposed changes to §117.205 replace the phrase “pursuant to” in §117.205(a)(1) and (3) with “in accordance with” for consistency with the agency's style guidelines.

The proposed changes to §117.205 also delete a reference to §117.540 in §117.205(a)(3) because §117.540 is proposed for repeal, as described later in this preamble.

The proposed changes to §117.206, concerning Emission Specifications for Attainment Demonstrations, delete the alternate ESADs in §117.206(c)(18)(A) - (Q) which were provided by BCCA-AG as part of the Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC. Specifically, in January 2001, BCCA-AG and others filed suit against the commission challenging the December 6, 2000 SIP revision for HGA and five of the ten sets of rules associated with that SIP revision. As part of that lawsuit, the plaintiffs sought a temporary injunction to stay the effectiveness of these five sets of rules and for the commission to withdraw the SIP from EPA consideration. A hearing on this request was held before Judge Margaret Cooper, Travis County District Court, Texas, on May 14 - 18, 2001. Before that hearing was completed, an agreement in principle was reached to settle the lawsuit, and a Consent Order was entered by Judge Cooper which includes certain specific items included in the SIP revision and rules in Chapters 101 and 117 proposed by the commission on May 30, 2001 (see the June 15, 2001 issue of the *Texas Register* (26 TexReg 4380 and 4400, respectively)) and subsequently adopted on September 26, 2001 (see the October 12, 2001 issue of the *Texas Register* (26 TexReg 8073 and 8110, respectively)).

In the December 2000 adoption of the original ESADs to achieve approximately 90% reductions in NO_x point source emissions, the commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of those ESADs. The commission determined that the various controls which can be used to meet the ESADs have a proven performance experience and that the 90% reductions are technically feasible. A detailed explanation of how the commission reached these conclusions is given in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524).

The September 26, 2001 adoption of revisions to Chapter 117 included changes to §117.206 which added ESADs in HGA for stationary diesel engines as a new §117.206(c)(9)(D). The justification for this change is described in detail in the October 12, 2001 issue of the *Texas Register* (26 TexReg 8110).

The commission is proposing to delete the current ESADs of §117.206(c)(1) - (17) and replace them with the alternate ESADs of §117.206(c)(18)(A) - (Q) which were provided by BCCA-AG as part of the Consent Order submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC.

For certain source categories, the alternate ESADs of §117.206(c)(18) are identical to the corresponding current ESADs of §117.206(c)(1) - (17). The specific categories are in the following rules: §115.206(c)(1)(C), (2)(B) and (C), (3), (4), (6), (7), (8)(C), (9)(A)(i) and (B) - (D), and (12) - (17). Although the proposed implementation of the BCCA-AG's alternate ESADs would not result in more lenient ESADs for the source categories specified in §115.206(c)(1)(C), (2)(B) and (C), (3), (4), (6), (7), (8)(C), (9)(A)(i) and (B) - (D), and (12) - (17), the commission solicits comments on equitableness of these ESADs as compared to the proposed change of the ESADs for other source categories.

The proposed changes to §117.206 also revise §117.206(c)(7) to clarify that the ESAD for oil-fired boilers applies not just to boilers firing oil, but to boilers firing any liquid fuel which does not cause the unit to fall under the hazardous waste-fired boilers and industrial furnaces (BIF unit) ESAD. This change is consistent with the current §117.206(c)(18)(G), and the commission's intent to make this change was discussed in the October 12, 2001 issue of the *Texas Register* (26 TexReg 8137).

In addition, the proposed changes to §117.206 revise §117.206(c)(9) to clarify that the emission specification for diesel engines is the lower of 11.0 grams per horsepower-hour (g/hp-hr) or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data. This change is necessary to ensure that an inadvertent windfall is not created for existing diesel engines which emit less than 11.0 g/hp-hr.

The proposed changes to §117.206 also revise §117.206(c)(17), which provides an ESAD for a unit with an annual capacity factor of 0.0383 or less, to specify that averaging may be used to determine eligibility for this ESAD. Specifically, the proposed revisions state that for units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor is used to determine whether the unit is eligible for the ESAD of these paragraphs. The proposed revisions further specify that for units placed into service after January 1, 1997, the annual capacity factor is calculated from two consecutive years in the first five years of operation to determine whether the unit is eligible for the emission specification of these paragraphs (using the same two consecutive years chosen for the activity level baseline), and that the five-year period begins at the end of the adjustment period as defined in 30 TAC §101.350, concerning Definitions.

As described earlier in this preamble, the commission is proposing to delete the current §117.206(c)(18)(Q). Because the commission cannot simultaneously propose to delete and amend §117.206(c)(18)(Q), it is providing notice to interested parties that if the commission for any reason retains §117.206(c)(18)(Q) upon adoption of this rule proposal, the commission's intent is to add language similar to that proposed to be added to §117.206(c)(17) in order to specify that averaging may be used to determine eligibility for this ESAD.

In addition, the proposed changes to §117.206 revise §117.206(e)(1) to establish a CO limit of 775 ppmv at 7.0% O_2, dry basis, for wood fuel-fired boilers or process heaters. This is consistent with the existing CO limit for wood fuel-fired boilers or process heaters in §117.205(f)(2), which was established based on CO and O_2 emissions data indicating that wood fuel-fired boilers or process heaters do not attain the 400 ppmv CO at 3.0% O_2 standard. (See the June 10, 1994 issue of the *Texas Register* (19 TexReg 4530)). The 775 ppmv CO at 7.0% O_2 standard (1,000 ppmv CO at 3.0% O_2) represents reasonably tuned performance for a wood-fired boiler.

The proposed changes to §117.206 further revise §117.206(e)(2) by specifying the percent O_2 to which the existing ammonia limit of ten ppmv is to be corrected. The revisions follow the same convention used to correct the NO_x emission specifications for various units to a standard O_2 basis.

The proposed changes to §117.206 also revise §117.206(h)(3) to specify that changes after December 31, 2000 to a unit subject to an ESAD in §117.206(c) (an "ESAD unit") which result in increased NO_x emissions from a unit not subject to an ESAD in §117.206(c) (a "non-ESAD unit"), such as redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator with a maximum rated capacity of less than 40 MMBtu/hr or a flare, is only allowed if the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS or through stack testing, and a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit is made in accordance with 30 TAC §101.354, concerning Allowance Deductions. This is necessary to prevent circumvention due to the transfer of emissions from a unit under which these emissions would be controlled (i.e., a unit subject to an ESAD) to a unit that is not subject to the mass emissions cap and trade program (i.e., a unit without an ESAD) and therefore is uncontrolled. If a fuel or waste stream containing chemical-bound nitrogen was being directed to a non-ESAD unit on or before December 31, 2000, then any increase in the non-ESAD unit's NO_x emission rate that resulted after December 31, 2000 from increasing the amount of chemical-bound nitrogen directed to the non-ESAD unit is a change that would be subject to the requirement that the increase in NO_x emissions at the non-ESAD unit be determined using a CEMS or PEMS or through stack testing, with a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit made in accordance with the mass emissions cap and trade program.

In addition, the proposed changes to §117.206 add a new §117.206(h)(4) which specifies that a source which met the definition of major source on December 31, 2000 shall always be classified as a major source for purposes of Chapter 117. The new §117.206(h)(4) further specifies that a source which did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2000, but which at any time after December 31, 2000 becomes a major source, shall from that time forward always be classified as a major source for purposes of Chapter 117. This change, in conjunction with the corresponding new §117.475(g) described later in this preamble, is necessary to close a potential loophole for certain major sources. Currently, if a major source in HGA consists primarily of units which are not subject to an ESAD, includes one or more units for which an ESAD has been established, but is not subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, because the cumulative design capacity to emit of the units subject to ESADs is less than ten tons per year (tpy), it could be interpreted that this major NO_x emission source would not be required to make any emission reductions. It was never the commission's intention to exempt major NO_x emission sources which have a limited amount of affected units from reducing NO_x emissions. The proposed change will ensure that such sources are subject to the same ESADs and the same emission reduction requirements as other major sources.

The proposed changes to §117.206 also add a new §117.206(h)(4) which specifies that the low annual capacity factor ESAD available under §117.206(c)(17) for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. This change is necessary to ensure that reduced operation after December 31, 2000 cannot be used to qualify for a more lenient emission specification under §117.206(c)(17) than would otherwise apply to the unit.

Finally, the proposed changes to §117.206 add a new §117.206(i)(3) to exclude firewater pumps used for emergency response training conducted in the months of April through October from the current §117.206(i), which prohibits stationary diesel and dual-fuel engines in HGA from being started or operated for testing or maintenance between the hours of 6:00 a.m. and noon. The proposed change is necessary to minimize the potential for heat exhaustion due to the protective clothing worn by an in-house fire brigade during emergency response training.

The proposed changes to §117.207, concerning Alternative Plant-wide Emission Specifications, delete extraneous parentheses in §117.207(b), abbreviate pound NO_x per million British thermal units as lb NO_x/MMBtu in §117.207(b)(1)(A), abbreviate parts per million by volume as ppmv in §117.207(b)(1)(A) and (3), abbreviate megawatt as MW in §117.207(g)(3), correct the type of brackets used in the equation for in-stack NO_x in the figure in §117.207(g)(3), and add "or" to §117.207(i)(1).

The proposed changes to §117.207 also add a new §117.207(j) which specifies that after the applicable attainment demonstration SIP compliance date, the alternative plant-wide RACT emission specifications will no longer apply to equipment in HGA for which §117.206(c) has established a more stringent emission specification. This will avoid any potential conflicts of the RACT limits and the more stringent ESADs. For purposes of §117.207(j), the alternative plant-wide RACT emission specifications of §117.207 remain in effect until the emissions allocation for a unit under the HGA mass emissions cap are equal to or less than the allocation that would be calculated using the alternative plant-wide RACT emission specifications of §117.207.

The proposed changes to §117.213, concerning Continuous Demonstration of Compliance, revise §117.213(a)(1)(A) to specify that stationary gas turbines exempted under §117.205(h)(7) are subject to the totalizing fuel flow meter requirements. This revision is necessary because stationary gas turbines rated at 1.0 MW or greater were required to install totalizing fuel flow meters by November 15, 1999, but are exempt from the emission specifications of §117.205 under §117.205(h)(7). Consequently, the current wording of §117.213(a)(1)(A) inadvertently does not include stationary gas turbines in the 1.0 to 10.0 MW range. The proposed revision corrects this error.

The proposed changes to §117.213 also revise §117.213(c)(1)(I) to specify that the owner or operator of fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents) in HGA shall monitor the stack exhaust flow rate with a flow meter using the flow monitoring specifications of 40 CFR 60, Appendix B, Performance Specification 6 or 40 CFR 75, Appendix A.

This revision is necessary because the flow rate must be known in order to determine the mass emission rate.

In addition, the proposed changes to §117.213 revise §117.213(e)(1)(B)(ii) to provide an alternative to the CEMS relative accuracy requirements of 40 CFR 60, Appendix B, Performance Specification 2, and revise §117.213(e)(1)(C) to specify that an annual relative accuracy test audit (RATA) is required if the owner or operator chooses the optional alternative relative accuracy requirement of §117.213(e)(1)(B)(ii). The proposed revisions are necessary because 40 CFR 60 looks at relative accuracy in terms of percentage instead of an absolute value and was designed for much higher NO_x concentrations than the ESADs represent. Consequently, there is a potential to fail a RATA under 40 CFR 60 when a source is operating at very low NO_x concentrations (e.g., ten ppmv and below).

In addition, the proposed changes to §117.213 revise §117.213(e)(1)(C) to clarify that the ongoing quality assurance procedures specified in that subparagraph are to commence after the date the CEMS is required to be certified, which for ESAD compliance is not a single final compliance date.

In addition, the proposed changes to §117.213 revise §117.213(e)(3) and add a new §117.213(e)(4) to address the sharing of CEMS among more than one unit. The existing §117.213(e)(3) was developed for the NO_x RACT rules, with which affected units typically comply by meeting an individually enforceable limit, either directly through §117.205 or through averaging in accordance with §117.207. However, compliance with §117.206 and the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 in HGA is demonstrated through a limit on total annual tons of NO_x emitted to the atmosphere, such that it would be more effective for the NO_x CEMS requirements to be linked to stacks, rather than individual units. The proposed new §117.213(e)(4) enables the sharing of CEMS in this manner in HGA. The proposed new §117.213(e)(4) also specifies that all bypass stacks shall be monitored in order to quantify emissions directed through the bypass stack. This is necessary because under the mass emissions cap and trade program, all NO_x emissions are considered, including those from startup, shutdown, upset, and maintenance activities at affected units. The proposed new §117.213(e)(4) further specifies that exhaust streams of units which vent to a common stack do not need to be analyzed separately. The proposed changes to §117.213(e)(3)(B) clarify that for shared CEMS in BPA and DFW, the CEMS certification requirements must be met while the CEMS is operating in the time-shared mode.

The proposed changes to §117.213 also add a new §117.213(e)(5) which provides an alternative to the CEMS requirements of 40 CFR 60 specified in §117.213(e)(1). The new §117.213(e)(5) provides that an owner or operator may choose to comply with the CEMS requirements of 40 CFR 75. The proposed new paragraph is necessary because 40 CFR 60 looks at relative accuracy in terms of percentage instead of an absolute value, whereas 40 CFR 75 allows the use of an absolute difference. Because 40 CFR 60 was designed for much higher NO_x concentrations than the ESADs represent, there is a potential to fail a RATA under 40 CFR 60 when a source is operating at very low NO_x concentrations (e.g., ten ppmv and below). In addition, the existing §117.213(e)(4) has been renumbered as §117.213(e)(6) to accommodate the proposed new §117.213(e)(4) and (5), and a reference to the new §117.213(e)(5) has been added to §117.213(e)(1) to facilitate the new §117.213(e)(5) described earlier in this paragraph.

In addition, the proposed changes to §117.213 revise §117.213(f)(5)(A)(i)(I) and (C)(iii)(II) to provide an alternative to the CEMS relative accuracy requirements of 40 CFR 60, Appendix B, Performance Specification 2. The proposed revisions are necessary because 40 CFR 60 looks at relative accuracy in terms of percentage instead of an absolute value and was designed for much higher NO_x concentrations than the ESADs represent. Consequently, there is a potential to fail a RATA under 40 CFR 60 when a source is operating at very low NO_x concentrations (e.g., ten ppmv and below).

The proposed changes to §117.213 also add new §117.213(f)(5)(A)(ii)(IV) and (V) which revise the PEMS requirements by allowing temporary waivers of the r-correlation test based on certain cases. The proposed new §117.213(f)(5)(A)(ii)(IV) allows a waiver from the statistical tests and default reference method standard deviation values for the F-test according to the "TNRCC PEMS Protocol Draft," May 16, 1994. The proposed new §117.213(f)(5)(A)(ii)(V) provides a temporary waiver of the correlation analysis if the process design is such that it is technically impossible to vary the process to result in a concentration change sufficient to allow a successful correlation analysis statistical test, or if the data for a measured compound (e.g., NO_x, O_2) are determined to be autocorrelated according to the procedures of 40 CFR §75.41(b)(2), with the statistical test repeated at the next RATA to verify compliance with the correlation analysis statistical test requirement.

The proposed changes to §117.213 also revise §117.213(g)(1)(C) to refer to "engines used exclusively in emergency situations" rather than the more specific phrase "gas-fired emergency generators." This change will exclude diesel-fired engines used exclusively in emergency situations from the biennial testing specified in §117.213(g)(1)(B) and will ensure that these engines will not have to be started for no reason other than to conduct this testing.

The proposed changes to §117.213 also revise §117.213(i) to include a reference to §117.205(h)(9) which was inadvertently deleted in previous rulemaking. The proposed change restores the NO_x RACT run time meter requirement for stationary gas turbines and engines which operate less than 850 hours per year, based on a rolling 12-month average, and is necessary to ensure compliance with the 850 hours per year limit. In addition, the proposed changes to §117.213 correct a section title in §117.213(m).

The proposed changes to §117.214, concerning Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration, add a new §117.214(a)(1)(D) which requires that ammonia monitoring be applied to units which inject urea or ammonia into the exhaust stream for NO_x control. The commission is proposing several options for ammonia slip monitoring in order to provide flexibility and minimize cost. The first option is to calculate the slip with a mass balance, as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of SCR. Because this option relies on process parameters routinely monitored in SCR systems, it is the least expensive procedure and is commonly specified in NSR permits. The permits typically require annual calibration of this method using a stack emission test for ammonia. The commission seeks comments on the usefulness of this stack test calibration based on recent experience. The second option is to monitor ammonia slip more directly by splitting the exhaust sample stream, converting the ammonia to NO in one stream with a thermal oxidizer, and measuring the ammonia as the difference between the converted and unconverted samples. This is the slip monitoring approach recommended by the Institute of Clean Air Companies at http://www.icac.com/noxgaswp.pdf. By alternately measuring streams, it may be feasible to monitor ammonia using an already required downstream NO_x analyzer, which would eliminate the cost of a separate analyzer. The third option is to use another method as approved by the executive director. A number of commercial methods of monitoring ammonia slip are described in the EPA's "Ammonia CEMS Background Report," June 14, 1993, available at http://www.epa.gov/ttn/emc/cem.html.

Control of the excess ammonia generation is a part of the science, as well as the economics, of post-combustion controls which utilize urea or ammonia as a reagent, and a competently designed and operated post-combustion control system will minimize excess ammonia generation. Minimizing ammonia slip depends on designing the system such that injected ammonia is properly mixed and well distributed and such that the amount of catalyst (in the case of SCR) is sufficient to control both NO_x and ammonia to the desired levels. Nevertheless, there will be an increase in ammonia emissions due to ammonia slip associated with the use of post-combustion control technologies. It is desirable to minimize ammonia emissions due to the concern that significantly increased ammonia emissions will enhance formation of $PM_{2.5}$. Consequently, monitoring for ammonia emissions is necessary. The proposed changes to §117.214 also renumber the existing §117.214(a)(1)(D) as §117.214(a)(1)(E) to accommodate the new §117.214(a)(1)(D).

In addition, the proposed changes to §117.214 revise §117.214(b)(2) to specify that quarterly NO_x and CO emission checks are not required for engines equipped with CEMS or PEMS, since these quarterly checks are intended to be a substitute for CEMS or PEMS. The proposed changes to §117.214 also add a new §117.214(b)(3) which specifies that each stationary internal combustion engine controlled with nonselective catalytic reduction (NSCR) shall be equipped with an automatic air-fuel ratio (AFR) controller which operates on exhaust O_2 or CO control and maintains AFR in the range required to meet the engine's applicable emission limits. This change is necessary because an automatic AFR controller is necessary for NSCR to work reliably. In addition, the proposed changes to §117.214 revise the catchline in §117.214(b) to specify "operating requirements" because the proposed AFR requirement is more appropriately categorized as an operating requirement rather than a testing requirement.

In addition, the proposed changes to §117.214 revise §117.214(c)(2)(C) to clarify that any retesting at a unit not equipped with a CEMS or PEMS establishes a new emission factor to be used to calculate actual emissions from the date of the retesting forward, with the previously determined emission factor used to calculate actual emissions for compliance with the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, until the date of the retesting. The proposed changes to §117.214 also abbreviate continuous emissions monitoring system and predictive emissions monitoring system in §117.214(c)(2).

Finally, the proposed changes to §117.214 add a new §117.214(c)(2)(D) which requires that all test reports be submitted to the executive director for review and approval within 60 days after completion of the testing. This is consistent with the existing requirements of Chapter 117 and is necessary to ensure the integrity and accuracy of testing.

The proposed changes to §117.215, concerning Final Control Plan Procedures for Reasonably Available Control Technology, correct the reference in §117.215(a)(2)(E) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)). The proposed changes to §117.215 also abbreviate million British thermal units per hour in §117.215(a)(6).

The proposed changes to §117.216, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, correct the reference in §117.216(a)(1)(C) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)). In addition, the proposed changes to §117.216 add a new §117.216(a)(1)(D) which references §117.207. This change is necessary because §117.207 is an option for compliance in BPA and DFW under §117.206(f)(1)(A). The proposed changes to §117.216 also revise a reference from §117.206(a) and (b) to §117.206 and add a new §117.216(a)(1)(E) which references the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, and §117.210, concerning System Cap. These changes are necessary to ensure that sources in HGA submit the required information necessary to document compliance.

In addition, the proposed changes to §117.216 revise §117.216(a)(4) by replacing a reference to the Austin office with a reference to the central office to avoid confusion with the Austin regional office. Finally, the proposed changes to §117.216 add a new §117.216(a)(6) that specifies which information is to be submitted for EGFs subject to the system cap of §117.210. This is necessary to ensure that EGFs in HGA submit the required information necessary to document compliance (for example, the calculations used to calculate the 30-day average and maximum daily system cap allowable emission rates).

The proposed changes to §117.219, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.219(a) by replacing a reference to §101.11 with a reference to §101.222. Section 101.222 was proposed in the April 26, 2002 issue of the *Texas Register* (27 TexReg 3475) and, if adopted, will replace the current §101.11.

The proposed changes to §117.219 also revise §117.219(b)(1) to clarify that verbal notification of the date of any testing conducted under §117.211 must be made at least 15 days prior to such date followed by written notification within 15 days after testing is completed. Likewise, the proposed changes to §117.219(c) clarify that results of testing conducted under §117.211 must be provided to the TNRCC central and regional offices and any local air pollution control agency having jurisdiction. This revision is necessary to ensure that any retesting conducted under §117.214(c)(2) is subject to the same notification and test result reporting requirements as the initial test.

The proposed changes to §117.219 also revise §117.219(e) to replace the phrase "rich-burn" with "gas-fired" because this rule also applies to lean-burn engines. In addition, the proposed changes to §117.219 replace a reference to quarterly reports in §117.219(e) with a reference to semiannual reports for consistency with references to these reports in §117.520(a)(2)(B) and elsewhere in §117.219(e). A semiannual reporting frequency is consistent with the reporting frequency specified for federal operating permits in 30 TAC §122.145, concerning Reporting Terms and Conditions. Affected owners and operators may maintain a quarterly schedule, if they prefer.

The proposed changes to §117.221, concerning Alternative Case Specific Specifications, clarify that requests for alternate CO or ammonia limits are evaluated by the Engineering Services Team, Office of Compliance and Enforcement. It should be noted that the paragraphs (§117.106(d) and §117.206(e)) addressing pollutants which may increase as an incidental result of compliance with the NO_x limits, specifically, CO and ammonia, continue to be excluded from the SIP. The proposed changes to §117.221 also revise a reference in §117.221(a)(2) from RACT to §117.205 or §117.206. This change is necessary because the ESADs of §117.206 go beyond RACT in some cases.

The proposed changes to §117.223, concerning Source Cap, abbreviate EPA in §117.223(a)(4) and revise §117.223(b)(1) to correct an inadvertent restriction on the use of the source cap. Specifically, the source cap in §117.223 is given as an option for compliance with the lean-burn engine emission specifications in §117.205(e) which are applicable in BPA. A company in BPA would like to use the source cap for their lean-burn engines, putting them into a cap with their boilers and heaters which are subject to the §117.205(a) - (d) RACT emission limits up until May 1, 2003, when the more stringent boiler and heater limits in §117.206 become applicable. However, the existing rule language seems to inadvertently prohibit them from combining the engines, boilers, and heaters into one source cap until May 1, 2003. The definition of H_i in the figure in §117.223(b)(1), variable (A), requires that the boilers and heaters complying with §117.205(a) - (d) use the original RACT heat input baseline within 1990 - 1993, and in variable (B) requires the lean burn engines and boilers and heaters under the ESAD to use the 1997 - 1999 baseline, while both §117.223(a) and (b) specify use of the same heat input baseline for all sources in the cap. For sources in BPA complying with the lean-burn engine emission specifications in §117.205(e), the revision to the definition of H_i in the figure in §117.223(b)(1), variable (B), will allow the owner or operator to combine the source cap with sources complying with §117.205(a) - (d) of this title, using the 1997 - 1999 heat input baseline described in the figure in §117.223(b)(1), variable (A), for the sources complying with §117.205(a) - (d). In addition, the revisions to the definition of R_i in the figure in §117.223(b)(1), variables (A)(ii) and (B)(ii), and to §117.223(c)(2) replace the phrase "pursuant to" with "in accordance with" for consistency with the agency's style guidelines. The proposed changes to §117.223 also spell out Code of Federal Regulations in §117.223(c)(2).

In addition, the proposed changes to §117.223 add a new §117.223(l) which specifies that after the applicable attainment demonstration SIP compliance date, the RACT source cap will no longer apply to equipment in HGA for which §117.206(c) has established a more stringent emission specification. This will avoid any potential conflicts of the RACT limits and the more stringent ESADs. For purposes of §117.223(l), the RACT source cap of §117.223 remains in effect until the emissions allocation for a unit under the HGA mass emissions cap are equal to or less than the allocation that would be calculated using the RACT source cap of §117.223.

The proposed changes to §117.301, concerning Applicability, revise the sentence structure for improved readability and revise "undesignated head" to "division" in response to revised *Texas Register* rules (see the February 13, 1998 issue of the *Texas Register* (23 TexReg 1289)).

The proposed change to §117.309, concerning Control Plan Procedures, revises “undesignated head” to “division” in response to revised *Texas Register* rules.

The proposed change to §117.311, concerning Initial Demonstration of Compliance, replaces a reference to "the effective date of this rule" in §117.311(d) with the actual date (June 23, 1994).

The proposed changes to §117.313, concerning Continuous Demonstration of Compliance, update the reference to the PEMS requirements of §117.213 due to a recent renumbering of this section; revise the sentence structure for improved readability; revise “undesignated head” to “division” in response to revised *Texas Register* rules; and replace "Texas Natural Resource Conservation Commission (commission)" with "commission" due to the forthcoming change in the agency's name.

The proposed changes to §117.319, concerning Notification, Recordkeeping, and Reporting Requirements, revise references to the TNRCC and the EPA for consistency with the agency's style guidelines. The proposed changes to §117.319 also revise the record retention time specified in recordkeeping, §117.319(d), from two years to five years for consistency. The sources subject to Chapter 117 are also subject to FCAA, Title V permit requirements, which specify a five-year period for retention of compliance records.

The proposed changes to §117.321, concerning Alternative Case Specific Specifications, revise a reference to the EPA for consistency with the agency's style guidelines; change a reference from RACT to the specific section (§117.305); update a reference to a section which has been repealed; and revise “undesignated head” to “division” in response to revised *Texas Register* rules.

The proposed changes to §117.401, concerning Applicability, revise the sentence structure for improved readability; revise “undesignated head” to “division” in response to revised *Texas Register* rules; and correct a reference to the title of the division.

The proposed changes to §117.409, concerning Control Plan Procedures, revise “undesignated head” to “division” in response to revised *Texas Register* rules and correct a reference to the title of the division.

The proposed change to §117.411, concerning Initial Demonstration of Compliance, replaces a reference to "the effective date of this rule" in §117.411(d) with the actual date (June 23, 1994).

The proposed changes to §117.413, concerning Continuous Demonstration of Compliance, update the reference to the PEMS requirements of §117.213 due to a recent renumbering of this section; revise the sentence structure for improved readability; revise “undesignated head” to “division” in response to revised *Texas Register* rules; correct a reference to the title of the division; and replace "Texas Natural Resource Conservation Commission (commission)" with "commission" due to the forthcoming change in the agency's name.

The proposed changes to §117.419, concerning Notification, Recordkeeping, and Reporting Requirements, revise references to the TNRCC and the EPA for consistency with the agency's style guidelines. The proposed changes to §117.419 also delete two section titles in §117.419(b) because the titles are included earlier in this section. In addition, the proposed changes to §117.419 revise the record retention time specified in recordkeeping, §117.419(d), from two years to five years for consistency. The sources subject to Chapter 117 are also subject to FCAA, Title V permit requirements, which specify a five-year period for retention of compliance records.

The proposed changes to §117.421, concerning Alternative Case Specific Specifications, revise a reference to the EPA for consistency with the agency's style guidelines; change a reference from RACT to the specific section (§117.405); revise “undesignated head” to “division” in response to revised *Texas Register* rules; and replace a reference to §103.71, concerning Request for Action by the Commission (which has been repealed), with a reference to §50.39, concerning Motion for Reconsideration, and §50.139, concerning Motion to Overturn Executive Director’s Decision.

The proposed changes to §117.463, concerning Exemptions, add exemptions for manufacturers and distributors of water heaters, small boilers, and process heaters which exceed the emission limits of §117.465, concerning Emission Specifications, but which are intended for shipment and use outside of Texas. The new exemptions are necessary because some Texas manufacturers also market their products outside of Texas. Similarly, some manufacturers may produce units that exceed the emission limits of §117.465 and ship them to a Texas distribution center which then ships them outside of Texas.

The proposed change to §117.465, concerning Emission Specifications, corrects a typographical error in §117.465(4)(B) by deleting "per hour."

The proposed change to §117.467, concerning Certification Requirements, corrects a reference to the South Coast Air Quality Management District because the rule currently lacks "Quality."

The proposed changes to §117.473, concerning Exemptions, revise §117.473(2)(E), (H)(ii), and (I)(ii) by deleting "effective" before the date of the revisions to 40 CFR §60.15 (December 16, 1975) because this date is the date of publication in the *Federal Register*, rather than the effective date of 40 CFR §60.15.

The proposed changes to §117.475, concerning Emission Specifications, revise §117.475(c)(4)(A) to clarify that the emission specification for diesel engines is the lower of 11.0 g/hp-hr or the emission rate established by testing, monitoring, manufacturer’s guarantee, or manufacturer’s other data. This change is necessary to ensure that an inadvertent windfall is not created for existing diesel engines which emit less than 11.0 g/hp-hr.

In addition, the proposed changes to §117.475 revise §117.475(c)(6), which provides an ESAD for a unit with an annual capacity factor of 0.0383 or less, to specify that averaging may be used to determine eligibility for this ESAD. Specifically, the proposed revisions state that for units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor is used to determine whether the unit is eligible for the ESAD of this paragraph. The proposed revisions further specify that for units placed into service after January 1, 1997, the annual capacity factor is calculated from two consecutive years in the first five years of operation to determine whether the unit is eligible for the emission specification of this paragraph (using the same two consecutive years chosen for the activity level baseline), and that the five-year period begins at the end of the adjustment period as defined in §101.350.

The proposed changes to §117.475 also revise §117.475(f) to specify that changes after December 31, 2000 to a unit subject to an ESAD in §117.475(c) (an "ESAD unit") which result in increased NO_x emissions from a unit not subject to an ESAD in §117.206(c) (a "non-ESAD unit"), such as redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator with a maximum rated capacity of less than 40 MMBtu/hr or a flare, is only allowed if the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS or through stack testing, and a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit is made as specified in §101.354. This is necessary to prevent circumvention due to the transfer of emissions from a unit under which these emissions would be controlled (i.e., a unit subject to an ESAD) to a non-ESAD unit which consequently is uncontrolled. If a fuel or waste stream containing chemical-bound nitrogen was being directed to a non-ESAD unit on or before December 31, 2000, then any increase in the non-ESAD unit's NO_x emission rate that resulted after December 31, 2000 from increasing the amount of chemical-bound nitrogen directed to the non-ESAD unit is a change that would be subject to the requirement that the increase in NO_x emissions at the non-ESAD unit be determined using a CEMS or PEMS or through stack testing, with a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit made in accordance with the mass emissions cap and trade program.

In addition, the proposed changes to §117.475 add a new §117.475(g) which specifies that a source which met the definition of major source on December 31, 2000 shall always be classified as a major source for purposes of Chapter 117. The new §117.475(g) further specifies that a source which did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2000, but which at any time after December 31, 2000 becomes a major source, shall from that time forward always be classified as a major source for purposes of Chapter 117. This change, in conjunction with the corresponding change to §117.206(h)(4) described earlier in this preamble, is necessary to close a potential loophole for certain major sources. Currently, if a major source in HGA consists primarily of units which are not subject to an ESAD, includes one or more units for which an ESAD has been established, but is not subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, because the cumulative design capacity to emit of the units subject to ESADs is less than ten tpy, it could be interpreted that this major NO_x emission source would not be required to make any emission reductions. It was never the commission's intention to exempt major NO_x emission sources which have a limited amount of affected units from reducing NO_x emissions. The proposed change will ensure that such sources are subject to the same ESADs and the same emission reduction requirements as other major sources.

The proposed changes to §117.475 also add a new §117.475(h) which specifies that the low annual capacity factor ESAD available under §117.475(c)(6) for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. This change is necessary to ensure that reduced operation after December 31, 2000 cannot be used to qualify for a more lenient emission specification under §117.475(c)(6) than would otherwise apply to the unit.

Finally, the proposed changes to §117.475 add a new §117.475(i) which specifies ammonia and CO limits. The new limits are necessary to prevent large increases in ammonia and CO emissions concurrent with the installation of NO_x controls, and represent a maximum rate under good engineering practice. Testing for these pollutants is already required under §117.479(e)(1) and (2). The commission is excluding these related pollutant limits of the proposed §117.475(i) from the SIP in order to simplify the approval process for alternative emission specifications under the proposed new §117.481, concerning Alternative Case Specific Specifications. 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 proposed change to §117.478, concerning Operating Requirements, adds a new §117.478(c)(3) to exclude firewater pumps used for emergency response training conducted in the months of April through October from the current §117.478(c), which prohibits stationary diesel and dual-fuel engines in HGA from being started or operated for testing or maintenance between the hours of 6:00 a.m. and noon. The proposed change is necessary to minimize the potential for heat exhaustion due to the protective clothing worn by an in-house fire brigade during emergency response training.

The proposed changes to §117.479, concerning Monitoring, Recordkeeping, and Reporting Requirements, add a new §117.479(e)(2) which requires that ammonia monitoring be applied to units which inject urea or ammonia into the exhaust stream for NO_x control. The commission is proposing several options for ammonia slip monitoring in order to provide flexibility and minimize cost. The first option is to calculate the slip with a mass balance, as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of SCR. Because this option relies on process parameters routinely monitored in SCR systems, it is the least expensive procedure and is commonly specified in NSR permits. The permits typically require annual calibration of this method using a stack emission test for ammonia. The commission seeks comments on the usefulness of this stack test calibration based on recent experience. The second option is to monitor ammonia slip more directly by splitting the exhaust sample stream, converting the ammonia to NO in one stream with a thermal oxidizer, and measuring the ammonia as the difference between the converted and unconverted samples. This is the slip monitoring approach recommended by the Institute of Clean Air Companies at http://www.icac.com/noxgaswp.pdf. By alternately measuring streams, it may be feasible to monitor ammonia using an already required downstream NO_x analyzer, which would eliminate the cost of a separate analyzer. The third option is to use another method as approved by the executive director. A number of commercial methods of monitoring ammonia slip are described in the EPA's "Ammonia CEMS Background Report," June 14, 1993, available at http://www.epa.gov/ttn/emc/cem.html.

Control of the excess ammonia generation is a part of the science, as well as the economics, of post-combustion controls which utilize urea or ammonia as a reagent, and a competently designed and operated post-combustion control system will minimize excess ammonia generation. Minimizing ammonia slip depends on designing the system such that injected ammonia is properly mixed and well distributed and such that the amount of catalyst (in the case of SCR) is sufficient to control both NO_x and ammonia to the desired levels. Nevertheless, there will be an increase in ammonia emissions due to ammonia slip associated with the use of post-combustion control technologies. It is desirable to minimize ammonia emissions due to the concern that significantly increased ammonia emissions will enhance formation of $PM_{2.5}$. Consequently, monitoring for ammonia emissions is necessary. The proposed changes to §117.479 also renumber the existing §117.479(e)(2) as §117.479(e)(3) to accommodate the new §117.479(e)(2).

In addition, the proposed changes to §117.479 revise §117.479(e)(7)(C) to clarify that any retesting at a unit not equipped with a CEMS or PEMS establishes a new emission factor to be used to calculate actual emissions from the date of the retesting forward, with the previously determined emission factor used to calculate actual emissions for compliance with the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 until the date of the retesting.

The proposed changes to §117.479 add a new §117.479(e)(9) which requires that all test reports be submitted to the executive director for review and approval within 60 days after completion of the testing. This is consistent with the existing requirements of Chapter 117 and is necessary to ensure the integrity and accuracy of testing. Finally, the proposed changes to §117.479 abbreviate carbon monoxide as CO in §117.479(g)(4).

The proposed new §117.481 allows alternative emission specifications to be established on a case specific basis for CO and ammonia. The commission is excluding these related pollutant limits from the SIP in order to simplify the approval process for alternative emission specifications. 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 proposed changes to §117.510, concerning Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas, add new §117.510(a)(2)(C) and (b)(2)(A)(iii) which specify a May 1, 2003 compliance date for installation of CEMS or PEMS on previously exempt units in BPA and DFW and completion of applicable CEMS or PEMS evaluations and quality assurance procedures specified in §117.113. The previously exempt units include utility boilers which are not subject to 40 CFR Part 75 NO_x monitoring (i.e., those rated at up to 25 MW) and utility boilers claimed exempt from NO_x RACT using the low annual capacity factor exemption of §117.103(a)(2), concerning Exemptions. A CEMS or PEMS is necessary for these units to be able to demonstrate compliance with §117.106(a) and (b).

The proposed changes to §117.510 also delete §117.510(c)(2)(E) because the proposed deletion of the alternate ESADs in §117.106(c)(5) makes §117.510(c)(2)(E) unnecessary. Because the alternate ESADs are proposed to be implemented through relocation to §117.106(c)(1) - (3), the current language of §117.510(c)(2)(E)(i) is proposed to replace the current language of §117.510(c)(2)(B)(iii)(I). Similarly, the current language of §117.510(c)(2)(E)(ii) is proposed to become a new §117.510(c)(2)(B)(iii)(III). The proposed new §117.510(c)(2)(B)(iii)(II) requires submission, by March 31, 2004, of the information specified in §117.116, which, as described earlier in this preamble, is necessary to document compliance. This information would include, for example, the calculations used to calculate the 30-day average and maximum daily system cap allowable emission rates.

The proposed changes to §117.512, concerning Compliance Schedule for Utility Electric Generation in East and Central Texas, specify how compliance with the regional electric utility requirements is determined in the remainder of the calendar year following the final compliance date (either May 1, 2003 or May 1, 2005). Because compliance with the NO_x emission specifications and optional system cap is on an annual basis, the proposed changes specify that the first year's compliance is determined using the period of May 1 through April 30, with compliance for each subsequent annual period on a calendar year basis. The proposed changes also specify that the updated final control plan required by §117.145, concerning Final Control Plan Procedures, shall be submitted no later than one month after the end of the first year's compliance period, and by January 31 of the next calendar year. These changes are consistent with the intent of the current rule language.

The proposed changes to §117.520, concerning Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas, revise the system cap compliance schedule for non-utility EGFs in §117.520(c)(2)(B)(iii) by deleting the intermediate compliance dates. The commission proposes this to eliminate the unnecessarily complicated schedule and to allow the affected industries more options for planning and implementing incremental reductions in emissions. The proposed amendment would not affect the March 31, 2007 final compliance date nor would it increase final emission rates, and would still achieve the final emission reductions as required by the SIP.

In addition, the proposed changes to §117.520 delete §117.520(c)(2)(C) because the proposed deletion of the alternate ESADs in §117.206(c)(18) makes §117.520(c)(2)(C) unnecessary. Subsequent subparagraphs are proposed to be relettered due to the proposed deletion of §117.520(c)(2)(C).

The proposed changes to §117.520 also add a new §117.520(c)(2)(F) which specifies that March 31, 2005 is the default compliance date for HGA attainment demonstration requirements that are not explicitly addressed elsewhere in §117.520(c)(2), such as the quarterly engine checks required by §117.214(b)(2).

The proposed changes to §117.534, concerning Compliance Schedule for Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources, add a new §117.534(1)(F) which specifies that March 31, 2005 is the default compliance date for HGA attainment demonstration requirements that are not explicitly addressed elsewhere in §117.534, such as the quarterly engine checks required by §117.478(b)(5). The proposed changes to §117.534 also switch the order of the existing §117.534(2)(C) and (D) for consistency with §117.534(1) and to make the order more logical.

Section 117.540, concerning Phased Reasonably Available Control Technology (RACT), is proposed for repeal because this section has been made obsolete by the passing of the March 31, 2001 final compliance date for RACT in DFW specified in §117.510(b)(1).

Section 117.560, concerning Recission, is proposed for repeal because this section has been made obsolete by determinations that NO_x reductions are necessary for attainment of the ozone standard. The FCAA, 42 USC, §7511a(f), requires that NO_x RACT be applied to all major sources of NO_x in ozone nonattainment areas, unless a demonstration is made that NO_x reductions would not contribute to, or would not be necessary for, attainment of the ozone standard. By policy, the EPA requires photochemical grid modeling to demonstrate whether the §7511a(f) NO_x measures would contribute to ozone attainment.

On April 16, 1999, EPA published notice in the *Federal Register* (64 FR 18864) that in order for BPA to take advantage of a policy which allows consideration of the effect of transport of ozone or its precursors from an upwind area, the commission must submit to EPA an acceptable SIP revision (by November 15, 1999) which includes any local control measures needed for expeditious attainment and proof that all applicable local control measures required under the moderate classification have been adopted. The commission met the "expeditious attainment" requirement of EPA's policy by providing for additional NO_x reductions in BPA through adoption of lean-burn engine NO_x rules on October 27, 1999. Commission staff conducted modeling for an ozone episode showing transport from HGA to BPA, as well as another ozone episode in which BPA's local emission contributions predominate in the formation of ozone, showing the need for more NO_x reductions in BPA in order for the area to attain the one-hour ozone standard. The commission adopted additional NO_x rules on April 19, 2000 in order for BPA to attain under these local contributions conditions.

On June 21, 1999, the EPA rescinded a 42 USC, §7511a(f), exemption from NO_x measures for DFW. EPA's rescission was based on its finding that NO_x reductions in DFW are necessary for attainment of the ozone standard. Similarly, the §7511a(f) exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under §7511a(f) was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the commission has made determinations for BPA, DFW, and HGA that NO_x reductions are necessary for attainment of the ozone standard in these ozone nonattainment areas, thereby rendering §117.560 obsolete.

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), TUC, §39.263(c)(1)(A) and (3): reductions of NO_x made in compliance with this rulemaking are hereby determined to be an essential component in achieving compliance with the NAAQS for ground-level ozone; and the amount and location of reductions of NO_x emissions resulting from this rulemaking are hereby determined to be consistent with the air quality goals and policies of the commission.

FISCAL NOTE: COSTS TO STATE AND LOCAL GOVERNMENT

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 units of state and local government as a result of administration or enforcement of the proposed amendments.

The current Chapter 117 requires a wide variety of stationary sources of NO_x emissions in HGA to meet emission specifications and other requirements in order to reduce NO_x emissions and ozone air pollution. The proposed amendments would change the NO_x emission specifications in HGA for some of the source categories. 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.

The current ESADs 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, and are a necessary and essential component of the 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. While the commission has proposed changing some of the current NO_x ESADs, detailed modeling which will quantitatively assess the overall effect of any changed ESADs, in conjunction with the proposed revisions to 30 TAC Chapter 115 to address highly-reactive VOCs, will be used in the development of the final ESADs.

All of the sources which will have to comply with the proposed rules are currently subject to Chapter 117 and, in many cases, air permits, and are already being inspected for compliance. Consequently, no additional facilities will need to be inspected for compliance with the proposed amendments. The commission anticipates that enforcement of these rules will not change the number of facilities currently inspected by the state and local governments.

The commission has already provided a detailed accounting of units of state and local government affected by the previously adopted ESADs in the COSTS TO STATE AND LOCAL GOVERNMENT sections of the preambles to the Chapter 117 rulemaking, which were published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8288) and in the June 15, 2001 issue of the *Texas Register* (26 TexReg 4413). In those issues of the *Texas Register,* the commission estimated that four ICI boilers at the Baylor College of Medicine and three ICI boilers at the University of Houston would be affected by the more stringent ESADs. If less stringent ESADs are adopted, there could be cost savings for owners and operators of affected units of state and local government. In the event that the current ESADs are retained, however, there would be no additional costs to owners and operators of affected units of state and local government beyond those described in the August 25, 2000 and June 15, 2001 issues of the *Texas Register*.

The commission estimates that there may be other state and local government facilities affected by the proposed amendments that have not been identified. 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 to costs already presented in the August 25, 2000 and June 15, 2001 issues of the *Texas Register*.

The commission anticipates no significant additional costs to units of state and local government due to the proposed new CO and ammonia emission limits for utility boilers and stationary gas turbines (including duct burners) in the 31 attainment counties of east and central Texas. The following units of government and the Lower Colorado River Authority (LCRA) will be affected by the new CO and ammonia standards: LCRA, owner of Sam Seymour EGF units 1, 2, and 3; the City of Austin, owner of Sam Seymour units 1, 2, and 3; the City of Bryan, owner of the Dansby unit 1 and Atkins unit 7; the City of San Antonio, owner of J.K. Spruce unit 1 and J.T. Deely units 1 and 2; and the cities of Bryan, Denton, Garland, and Greenville, which share ownership of the Gibbons Creek unit 1. The new limits are necessary to prevent large increases in ammonia and CO emissions concurrent with the installation of NO_x controls, and represent a maximum rate under good engineering practice. Testing for these pollutants is already required under existing commission regulations, and no additional cost is anticipated because the commission expects that the units are already meeting the proposed limits or, if retrofitted with NO_x controls in the future, will be able to meet the proposed limits without additional modifications.

The proposed amendments will also require all units in the eight-county HGA nonattainment area that inject urea or ammonia into the exhaust stream for NO_x control to implement procedures to monitor the amount of injected ammonia. 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 (FCCUs), 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. However, the only equipment types owned by units of state and local government which are anticipated to be affected by the ammonia monitoring requirements would be ICI boilers.

The four ICI boilers at the Baylor College of Medicine have a maximum capacity less than 40 MMBtu/hr and are expected to reduce emissions through the use of combustion modifications, such as low-NO_x burners or flue gas recirculation. Therefore, these boilers are not affected by the ammonia monitoring requirements. 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. These boilers are expected to reduce emissions through the use of SCR, and therefore would be affected by the ammonia monitoring requirements.

Currently, the commission knows of three types of ammonia monitoring options: 1) mass balance using software to calculate the ammonia emission rate using data being collected by a CEMS; 2) using a nitric oxide analyzer; or 3) using an ammonia CEMS or PEMS. The commission anticipates that option 1 would be the cheapest and easiest to implement; however, the commission does not have a cost estimate for this option. The cost estimate for option 2 is $25,000 per CEMS equipped to perform a material balance using data collected by the CEMS. Assuming that the four ICI boilers owned by the Baylor College of Medicine will control NO_x through injecting urea or ammonia into the exhaust stream and are all equipped with CEMS, the total capital cost would be approximately $100,000. The annual cost for quarterly cylinder gas audits for option 2 is estimated to be $3,500, for a maximum annual operating cost of approximately $14,000. The total capital and operating costs may be less since combustion modifications can be used in lieu of SCR, especially if the changed ESADs are adopted, because fewer units would need to use ammonia or urea injection to control NO_x emissions. Consequently, fewer units would have to monitor ammonia emissions.

PUBLIC BENEFITS AND COSTS

Mr. Davis determined that for each year of the first five years the proposed amendments are in effect, the public benefit anticipated from enforcement of and compliance with the proposed amendments will be potentially reduced costs associated with the reduction of public exposure to NO_x emitted from affected stationary sources, reduction of ground-level ozone in ozone nonattainment areas, and conformance with the requirements of the FCAA.

A detailed estimate of the estimated cost of complying with the current ESADs is given in the PUBLIC BENEFITS AND COSTS sections of the preambles to the Chapter 117 rulemaking, which were published in the August 25, 2000 and the June 15, 2001 issue of the *Texas Register*. If less stringent ESADs are adopted, there could be cost savings for owners and operators. In the event that the ESADs are retained, however, there would be no additional costs to owners and operators beyond those described in the August 25, 2000 and June 15, 2001 issues of the *Texas Register*.

There are no costs associated with the proposed new CO and ammonia emission limits for utility boilers and stationary gas turbines (including duct burners) in the 31 attainment counties of east and central Texas. The new limits are necessary to prevent large increases in ammonia and CO emissions concurrent with the installation of NO_x controls, and represent a maximum rate under good engineering practice. Testing for these pollutants is already required under existing commission regulations, and no additional cost is anticipated because the commission expects that the units are already meeting the proposed limits or, if retrofitted with NO_x controls in the future, will be able to meet the proposed limits without additional modifications.

The proposed amendments will require all units in the eight-county HGA nonattainment area that inject urea or ammonia into the exhaust stream for NO_x control to implement procedures to monitor the amount of injected ammonia. 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 and reheat furnaces; magnesium chloride fluidized bed dryers; incinerators; and BIF units. The commission estimates that there should be no more than 700 affected units which will control NO_x through injecting urea or ammonia into the exhaust stream, all of which would be required to be comply with continuous monitoring requirements.

Currently, the commission knows of three types of ammonia monitoring options: 1) mass balance using software to calculate the ammonia emission rate using data being collected by a CEMS; 2) using a nitric oxide analyzer; or 3) using an ammonia CEMS or PEMS. The commission anticipates that option 1 would be the cheapest and easiest to implement; however, the commission does not have a cost estimate for this option. The cost estimate for option 2 is $25,000 per CEMS equipped to perform a material balance using data collected by the CEMS. Assuming that the 700 units will control NO_x through injecting urea or ammonia into the exhaust stream are all equipped with CEMS, the total capital cost would be approximately $17,500,000. The annual cost for quarterly cylinder gas audits for option 2 is estimated to be $3,500, for a maximum annual operating cost of approximately $2,450,000 for the 700 CEMS. The total capital and operating costs may be less since combustion modifications can be used in lieu of SCR, especially if the changed ESADs are adopted, because fewer units would need to use ammonia or urea injection to control NO_x emissions. Consequently, fewer units would have to monitor ammonia emissions.

The proposed amendments would also require continuous monitoring of the stack exhaust flow rate on FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents). Flow monitoring is necessary because the flow rate must be known in order to determine the mass emission rate for determining compliance with the mass emissions cap and trade program. Based on an analysis of the 1997 emission inventory database, the proposed continuous monitoring of FCCUs will require, at most, 13 additional units to install and operate flow meters. In previous rulemaking (see the June 15, 2001 issue of the *Texas Register*), the commission estimated the initial cost of a CEMS which monitors NO_x, O_2, and flow to be approximately \$137,400 to \$179,600, with total annual costs of \$64,800 to \$66,000, based upon *U.S. EPA's Continuous Emission Monitoring System Cost Model, Version 3.0, 1998*. Based on these figures, the total cost for the additional NO_x CEMS or PEMS was estimated to be \$1.8 to \$2.3 million, with a total annual cost of approximately \$842,400 to \$858,000. The cost of FCCU flow monitors was included in this previous estimate. The flow monitors represent approximately \$21,600 of the estimated initial cost of a CEMS and approximately \$19,400 of the estimated total annual cost of a CEMS. Based on these figures, the portion of the total CEMS cost for the flow monitoring requirement is estimated to be \$280,800, with a total annual cost of approximately \$252,200. It should be noted that the EPA 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 because some of the costs are not repeated with the addition of a second CEMS or more.

SMALL BUSINESS AND MICRO-BUSINESS ASSESSMENT

No adverse fiscal implications are anticipated for small or micro-businesses as a result of implementation of the proposed amendments because none of the electric utilities subject to the proposed CO and ammonia emission limits for utility boilers and stationary gas turbines (including duct burners) are small or micro-businesses. Likewise, none of the FCCUs subject to the proposed flow monitoring requirements are owned by small or micro-businesses. In the previous August 25, 2000 and June 15, 2001 issues of the *Texas Register,* the commission could not identify any small or micro-business that would be affected by the proposed ESADs.

The commission has been unable to identify any small or micro-businesses which would be affected by the proposed amendments in this rulemaking. 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 the PUBLIC BENEFITS AND COSTS section of this preamble would appear to be a reasonable cost estimate for small or micro-businesses. As noted earlier in this preamble, there could be cost savings if more lenient ESADs are adopted. Regardless, no adverse fiscal implications are anticipated for small and micro-businesses as a result of implementing the proposed amendments.

LOCAL EMPLOYMENT IMPACT STATEMENT
The commission has reviewed this proposed rulemaking and determined that a local employment impact statement is not required because the proposed rules do not adversely affect a local economy in a material way for the first five years that the proposed rules are in affect.

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. A "major environmental rule" means a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure and that may adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

The proposed amendments to Chapter 117 and revisions to the SIP would amend requirements to achieve the intended NO_x emission reductions of the program. Specifically, the amendments to Chapter 117 will require emission reductions, and, for some facilities, revise the ESADs, 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 proposed 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. This is based on the analysis provided elsewhere in this preamble, including the discussion in the PUBLIC BENEFITS AND COSTS section of this proposal and in preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524). In addition, the proposed amendments add CO and ammonia emission specifications for electric generating facilities located in 31 attainment counties of east and central Texas. The remaining amendments in this rulemaking are intended to correct typographical errors, update cross-references, clarify ambiguous language, add flexibility and delete obsolete language, and these amendments are not expected to adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

The 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.

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, 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 were amended by Senate Bill (SB) 633 during the 75th Legislative Session. The intent of SB 633 was to require agencies to conduct an 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 specifically 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 will be submitted to the EPA as measures in the federally approved SIP. 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 commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App.–Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App.–Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

As discussed earlier in this preamble, this rulemaking implements requirements of the FCAA. There is no contract or delegation agreement that covers the topic that is the subject of this rulemaking. Therefore, the proposed rules do not exceed a standard set by federal law, exceed an express requirement of state law, exceed a requirement of a delegation agreement, nor are adopted solely under the general powers of the agency. In addition, the rules are proposed under the Texas Health and Safety Code (THSC), Texas Clean Air Act (TCAA), §§382.011, 382.012, 382.014, 382.016, 382.017, 382.021 and 382.051(d). The commission invites public comment on the draft RIA.

TAKINGS IMPACT ASSESSMENT

The commission completed a takings impact analysis for the proposed rules under Texas Government Code, §2007.043. The specific purposes of these amendments are to achieve reductions in NO_x emissions and 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, as well as to improve implementation of the existing Chapter 117 by correcting typographical errors, updating cross-references, clarifying ambiguous language, adding flexibility, and deleting obsolete language. 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.

Texas Government Code, §2007.003(b)(4), provides that Chapter 2007 does not apply to these proposed rules, because they are reasonably taken to fulfill an obligation mandated by federal law. The emission limitations and control requirements within this rulemaking were developed in order to meet the NAAQS for ozone set by the EPA under 42 USC, §7409. States are primarily responsible for ensuring attainment and maintenance of NAAQS once the EPA has established them. Under 42 USC, §7410, and related provisions, states must submit, for approval by the EPA, SIPs that provide for the attainment and maintenance of NAAQS through control programs directed to sources of the pollutants involved. Therefore, one purpose of this rulemaking action is to meet the air quality standards established under federal law as NAAQS. Attainment of the ozone standard will eventually require substantial NO_x reductions as well as reductions of highly-reactive VOC emissions. Any NO_x reductions resulting from the current rulemaking are no greater than what scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard.

In addition, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rule revisions do not directly prevent a nuisance or prevent an immediate threat to life or property, they do prevent a real and substantial threat to public health and safety and significantly advance the health and safety purpose. This action is taken in response to the HGA area exceeding the federal ambient air quality standard for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ozone levels in the HGA nonattainment area. Consequently, these proposed rules meet the exemption in §2007.003(b)(13). This rulemaking action therefore meets the requirements of Texas Government Code, §2007.003(b)(4) and (13). For these reasons, the proposed rules do not constitute a takings under Chapter 2007.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM
The commission reviewed the proposed rulemaking and found that the proposal is a rulemaking identified in Coastal Coordination Act Implementation Rules, 31 TAC §505.11, or will affect an action/authorization identified in Coastal Coordination Act Implementation Rules, 31 TAC §505.11, and therefore will require that applicable goals and policies of the Coastal Management Program be considered during the rulemaking process.

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

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMIT PROGRAM
Chapter 117 is an applicable requirement under 30 TAC Chapter 122; therefore, owners or operators subject to the Federal Operating Permit Program must, consistent with the revision process in Chapter 122, revise their operating permits to include the revised Chapter 117 requirements for each emission unit affected by the revisions to Chapter 117 at their sites.

ANNOUNCEMENT OF HEARINGS
Public hearings for this proposed rulemaking have been scheduled for the following times and locations: July 18, 2002, 2:00 p.m., Texas Natural Resource Conservation Commission, 12100 North I-35, Building E, Room 201S, Austin; July 22, 2002, 10:00 a.m., City of Houston, City Council Chambers, 2nd Floor, 901 Bagby, Houston; as well as July 22, 2002, 7:00 p.m., Flukinger Community Center, 16003 Lorenzo, Channelview. The hearings will be structured for the receipt of oral or written comments by interested persons. Registration will begin 30 minutes prior to the hearings. Individuals may present oral statements when called upon in order of registration. A four-minute time limit may be established at the hearings to assure that enough time is allowed for every interested person to speak. There will be no open discussion during the hearings; however, commission staff members will be available to discuss the proposal 30 minutes before the hearings and will answer questions before and after the hearings.

Persons planning to attend the hearings who have special communication or other accommodation needs, 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 Kelly Keel, MC 206, Office of Environmental Policy, Analysis, and Assessment, Texas Natural Resource Conservation Commission, P.O. Box 13087, Austin, Texas 78711-3087, faxed to (512) 239-4808, or emailed to *siprules@tceq.state.tx.us*. All comments should reference Rule Log Number 2002-038-117-AI. Comments must be received by 5:00 p.m., July 22, 2002, although oral and written comments submitted at the 7:00 p.m. July 22, 2002 hearing will be accepted. For further information, please contact Eddie Mack of the Strategic Assessment Division at (512) 239-1488.

SUBCHAPTER A: DEFINITIONS
§117.10

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

The proposed amendment implements TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d); and TWC, §5.103.

§117.10. Definitions.

Unless specifically defined in the Texas Clean Air Act or Chapter 101 of this title (relating to General Air Quality Rules), the terms in this chapter shall have the meanings commonly used in the field of air pollution control. Additionally, the following meanings apply, unless the context clearly indicates otherwise. Additional definitions for terms used in this chapter are found in §101.1 and §3.2 of this title (relating to Definitions).

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

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

(7) - (11) (No change.)

(12) **Duct burner** - A unit that combusts fuel and that is placed in the exhaust duct from another unit (such as a stationary gas turbine, stationary internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases.

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

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

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

(i) Beaumont/Port Arthur;

(ii) Dallas/Fort Worth; or

(iii) Houston/Galveston;

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

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

(15) [(14)] **Emergency situation** - As follows.

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

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

(ii) the period of time during which an emergency notice, as defined in *ERCOT Protocols, Section 2: Definitions and Acronyms* (May 1, 2002 [January 5, 2001]), issued by the Electric Reliability Council of Texas, Inc. (ERCOT) as specified in *ERCOT Protocols, Section 5: Dispatch* (April 1, 2002 [January 5, 2001]), is applicable to the serving electric power generating system. The emergency situation is considered to end upon expiration of the emergency notice issued by ERCOT;

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

(iv) an unforeseen failure of natural gas service;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(31) [(30)] **Megawatt (MW) rating** - The continuous MW output 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.

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

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

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

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

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

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

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

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

(40) [(39)] **Process heater** - Any combustion equipment fired with liquid and/or gaseous fuel which is used to transfer heat from combustion gases to a process fluid, superheated steam, or water for the purpose of heating the process fluid or causing a chemical reaction. The term "process heater" does not apply to any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment, or to boilers as defined in this section.

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

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

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

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

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

(46) [(45)] **Stationary internal combustion engine** - A reciprocating engine that remains or will remain at a location (a single site at a building, structure, facility, or installation) for more than 12 consecutive months. Included in this definition is any engine that, by itself or in or on a piece of equipment, is portable, meaning designed to be and capable of being carried or moved from one location to another. Indicia of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine being replaced is included in calculating the consecutive residence time period. An engine is considered stationary if it is removed from one location for a period and then returned to the same location in an attempt to circumvent the consecutive residence time requirement. Nonroad engines, as defined in 40 CFR §89.2, are not considered stationary for the purposes of this chapter.

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

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

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

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

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

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

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

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

(52) [(51)] **Utility boiler** - Any combustion equipment owned or operated by a municipality or Public Utility Commission of Texas regulated utility, fired with solid, liquid, and/or gaseous fuel, used to produce steam for the purpose of generating electricity. Stationary gas turbines, including any associated duct burners and unfired waste heat boilers, are not considered to be utility boilers.

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

SUBCHAPTER B: COMBUSTION AT MAJOR SOURCES
DIVISION 1: UTILITY ELECTRIC GENERATION IN OZONE NONATTAINMENT AREAS

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

The proposed repeal implements TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d); and TWC, §5.103.

§117.104. Gas-Fired Steam Generation.

SUBCHAPTER B: COMBUSTION AT MAJOR SOURCES
DIVISION 1: UTILITY ELECTRIC GENERATION IN OZONE NONATTAINMENT AREAS
§§117.105 - 117.108, 117.113 - 117.116, 117.119, 117.121

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

The proposed amendments implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d); and TWC, §5.103.

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

(a) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, emissions of nitrogen oxides (NO_x) in excess of 0.26 pound per million British thermal units (lb/MMBtu) [(MM) Btu] heat input on a rolling 24-hour average and 0.20 lb/MMBtu [pound per MMBtu] heat input on a 30-day rolling average while firing natural gas or a combination of natural gas and waste oil.

(b) No person shall allow the discharge into the atmosphere from any utility boiler, NO_x emissions in excess of 0.38 lb/MMBtu [pound per MMBtu] heat input for tangentially-fired units on a rolling 24-hour averaging period or 0.43 lb/MMBtu [pound per MMBtu] heat input for wall-fired units on a rolling 24-hour averaging period while firing coal.

(c) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of 0.30 lb/MMBtu [pound per MMBtu] heat input on a rolling 24-hour averaging period while firing fuel oil only.

(d) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of the heat input weighted average of the applicable emission limits specified in subsections (a) and (c) [(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)

Emission Limit = {a(0.26) + b(0.30)}/(a + b)

Where:

a = the percentage of total heat input from natural gas.
b = the percentage of total heat input from fuel oil.

(e) Each auxiliary steam boiler which is an affected facility as defined by New Source Performance Standards (NSPS) 40 Code of Federal Regulations (CFR), Part 60, Subparts D, Db, or Dc shall be limited to the applicable NSPS NO_x emission limit, unless the boiler is also subject to a more stringent permit emission limit, in which case the more stringent emission limit applies. Each auxiliary boiler subject to an emission specification under this subsection is not subject to the emission specifications of subsection (a), [or] (c), or (d) of this section.

(f) (No change.)

(g) No person shall allow the discharge into the atmosphere from any stationary gas turbine used for peaking service with an annual electric output in MW-hr of less than the product of 2,500 hours and the MW rating of the unit NO_x emissions in excess of a block one-hour average of:

(1) 0.20 lb/MMBtu [pound per MMBtu] heat input while firing natural gas; and

(2) 0.30 lb/MMBtu [pound per MMBtu] heat input while firing fuel oil.

(h) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler subject to the NO_x emission limits specified in subsections (a) - (e) of this section, carbon monoxide (CO) emissions in excess of 400 ppmv at 3.0% O_2, dry (or alternatively, 0.30 lb/MMBtu [pound per MMBtu] heat input for gas-fired units, 0.31 lb/MMBtu heat input for oil-fired units, and 0.33 lb/MMBtu heat input for coal-fired units), 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 in accordance with [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) (No change.)

§117.106. Emission Specifications for Attainment Demonstrations.

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

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

(c) Houston/Galveston. The owner or operator of each utility boiler, auxiliary steam boiler, or stationary gas turbine located in the Houston/Galveston ozone nonattainment area shall ensure that emissions of NO_x do not exceed the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the following rates, in lb/MMBtu heat input, on the basis of daily and 30-day averaging periods as specified in §117.108 of this title, and as specified in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program):

(1) utility boilers:

(A) gas-fired, 0.030 [0.020]; and

(B) coal-fired or oil-fired:

(i) wall-fired, 0.050; and

(ii) tangential-fired, 0.045 [, 0.040];

(2) auxiliary steam boilers:

(A) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.030 [0.010];

(B) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.030 [0.015]; and

(C) with a maximum rated capacity less 40 MMBtu/hr, 0.030 [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 (including duct burners used in turbine exhaust ducts):

(A) rated at 1.0 megawatt (MW) or greater, 0.032 [0.015]; and

(B) rated at less than 1.0 MW:

(i) with initial start of operation on or before December 31, 2000, 0.032 [0.15]; and

(ii) with initial start of operation after December 31, 2000, 0.032. [0.015; and]

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

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

January 2, 2001; or the emission specifications in the following subparagraphs. The commission reserves all rights to assign any additional NO_x reduction benefits supported by the science evaluation to the relief of other control measures, including further NO_x point source relief.]

[(A) utility boilers:]

[(i) gas-fired, 0.030;]

[(ii) coal-fired or oil-fired;]

[(I) wall-fired, 0.050; and]

[(II) tangential-fired, 0.045;]

[(B) auxiliary steam boilers, 0.030; and]

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

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

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

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

(2) ammonia emissions in excess of ten ppmv, at 3.0% O_2, dry, for boilers and 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

(e) Compliance flexibility.

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

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

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

(B) (No change.)

§117.107. Alternative System-wide Emission Specifications.

(a) An owner or operator of any gaseous- or coal-fired utility boiler or stationary gas turbine may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) by achieving compliance with a system-wide emission limitation. Any owner or operator who elects to comply with system-wide emission limits shall reduce emissions of NO_x from affected units so that, if all such units were operated at their maximum rated capacity, the system-wide emission rate from all units in the system as defined in §117.10(14)(A) [§117.10(13)(A)] of this title (relating to Definitions) would not exceed the system-wide emission limit as defined in §117.10 of this title.

(1) (No change.)

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

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

(b) (No change.)

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

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

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

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

(2) (No change.)

(e) This section shall no longer apply in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.510(c)(2) of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas). For purposes of this subsection, this means that the alternative plant-wide emission specifications of this section remain in effect until the emissions allocation for a unit under the Houston/Galveston mass emissions cap are equal to or less than the allocation that would be calculated using the alternative plant-wide 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 EGF [electric generating facility] in the Houston/Galveston ozone nonattainment area must comply with a daily and 30-day system cap emission limitation in accordance with the requirements of this section.

(b) Each EGF within an electric power generating system, as defined in §117.10(14)(A) [§117.10(13)(A)] of this title (relating to Definitions), that would otherwise be subject to the NO_x emission rates of §117.106 of this title must be included in the system cap.

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

§117.113. Continuous Demonstration of Compliance.

(a) NO_x monitoring. The owner or operator of each unit subject to the emission specifications of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas), shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS), predictive emissions monitoring system (PEMS), or other system specified in this section to measure nitrogen oxides (NO_x) on an individual basis. Each NO_x monitor (CEMS or PEMS) in the Beaumont/Port Arthur, Dallas/Fort Worth, or Houston/Galveston ozone nonattainment area is subject to the relative accuracy test audit (RATA) relative accuracy requirements of 40 Code of Federal Regulations (CFR) 75, Appendix B, Figure 2, except the concentration options (parts per million by volume (ppmv) and pound per million British thermal units(lb/MMBtu)) therein do not apply. Each NO_x monitor shall meet either the relative accuracy percent requirement of 40 CFR 75, Appendix B, Figure 2, or an alternative relative accuracy requirement of $\pm$ 2.0 ppmv from the reference method mean value.

(b) (No change.)

(c) CEMS requirements.

(1) (No change.)

(2) 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 and Dallas/Fort Worth ozone nonattainment area, one [One] CEMS may be shared among units, provided:

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

(3) For units in the Houston/Galveston ozone nonattainment area which are subject to §117.106 of this title (relating to Emission Specifications for Attainment Demonstrations):

(A) all bypass stacks shall be monitored in order to quantify emissions directed through the bypass stack;

(B) one CEMS may be shared among units, provided:

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

(ii) the CEMS meets the certification requirements of paragraph (1) of this subsection for each stack while the CEMS is operating in the time-shared mode; and

(C) exhaust streams of units which vent to a common stack do not need to be analyzed separately.

(d) - (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) - (ii) (No change.)

(B) (No change.)

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

(g) Stationary gas turbine monitoring for NO_x RACT. The owner or operator of each stationary gas turbine subject to the emission specifications of §117.105 of this title [(relating to Emission Specifications for Reasonably Available Control Technology (RACT))], instead of monitoring emissions in accordance with the monitoring requirements of 40 CFR 75, may comply with the following monitoring requirements:

(1) for stationary gas turbines rated less than 30 MW [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) (No change.)

(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) - (C) (No change.)

(2) (No change.)

(i) - (k) (No change.)

(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 in accordance with [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) - (3) (No change.)

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

(A) Mass balance. Calculate ammonia emissions as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of the control device which injects urea or ammonia into the exhaust stream. The equation is: ammonia parts per million by volume (ppmv) at reference oxygen = $\{(a/b)\ (10^6) - c\}(d)$, where reference oxygen is 3.0% for boilers and 15% for gas turbines; a = ammonia injection rate (in pounds per hour (lb/hr))/17 pound per pound-mole (lb/lb-mol); b = dry exhaust flow rate (lb/hr)/29 lb/lb-mol; c = change in measured NO_x concentration across catalyst (ppmv at reference oxygen); and d = correction factor, the ratio of measured slip to calculated ammonia slip, where the measured slip is obtained from the stack sampling for ammonia required by §117.111(a)(2) of this title (relating to Initial Demonstration of Compliance), using either the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method 27.

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

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

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

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

(c) Emission allowances.

(1) (No change.)

(2) For units not operating with a CEMS [continuous emissions monitoring system (CEMS)] or PEMS [predictive emissions monitoring system (PEMS)], the following apply.

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

(C) The NO_x emission rate determined by the retesting shall establish a new emission factor to be used to calculate actual emissions from the date of the retesting forward. Until the date of the retesting, [instead of] the previously determined emission factor shall be used to calculate actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(D) All test reports must be submitted to the executive director for review and approval within 60 days after completion of the testing.

(3) (No change.)

§117.115. Final Control Plan Procedures for Reasonably Available Control Technology.

(a) The owner or operator of units listed in §117.101 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)). The report must include a list of all units listed in §117.101 of this title, showing:

(1) the NO_x emission specification resulting from application of §117.105 of this title [(relating to Emission Specifications)] for each non-exempt unit;

(2) the section under which NO_x compliance is being established for units specified in paragraph (1) of this subsection, either:

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

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

(3) - (6) (No change.)

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

§117.116. Final Control Plan Procedures for Attainment Demonstration Emission Specifications.

(a) The owner or operator of utility boilers listed in §117.101 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit to the executive director a final control report to show compliance with the requirements of §117.106 of this title (relating to Emission Specifications for Attainment Demonstrations). The report must include:

(1) the section under which NO_x compliance is being established for the utility boilers within the electric generating system, either:

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

(C) §117.570 of this title (relating to <u>Use of Emissions Credits for Compliance</u> [Trading]); <u>or</u>

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

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

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

§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 <u>§101.222</u> [§101.11] of this title (relating to Demonstrations), hourly records shall be made of start-up and/or shutdown events and maintained for a period of at least two years. Records shall be available for inspection by the executive director, EPA, and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type fuel burned; gross and net energy production in megawatt-hours (MW-hr); and the date, time, and duration of the event.

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

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

(2) (No change.)

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

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

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

§117.121. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), or the carbon monoxide (CO) or ammonia limits of §117.106(d) of this title (relating to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.105 of this title or the CO or ammonia limits in §117.106(d) of this title for that unit. The executive director:

(1) (No change.)

(2) must determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of <u>controls to meet the nitrogen oxides emission specifications of §117.105 or §117.106 of this title, as applicable;</u> [reasonably available control technology; and]

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through system-wide averaging at maximum capacity<u>; and</u> [.]

<u>(4) is the Engineering Services Team, Office of Compliance and Enforcement, for purposes of this section.</u>

(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 <u>Motion for Reconsideration; and Motion to</u> Overturn Executive Director's Decision) apply. However, only a person affected may file a motion for reconsideration. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the EPA in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas).

DIVISION 2: UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS §§117.131, 117.135, 117.138, 117.141, 117.143, 117.149, 117.151

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

The proposed amendments and new section implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d); and TWC, §5.103.

§117.131. Applicability.

(a) The provisions of this division shall apply to each utility electric power boiler and stationary gas turbine (including duct burners used in turbine exhaust ducts) that:

(1) generates electric energy for compensation;

(2) is owned or operated by an electric cooperative, independent power producer, municipality, river authority, or public utility, or any of its successors;

(3) was placed into service before December 31, 1995; and

(4) is 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.

(b) The provisions of §117.134 of this title (relating to Gas-Fired Steam Generation) also apply in Palo Pinto County.

§117.135. Emission Specifications.

In accordance with the compliance schedule in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas), the owner or operator of each utility electric power boiler or stationary gas turbine (including duct burners used in turbine exhaust ducts) shall:

(1) ensure that emissions of nitrogen oxide (NO_x) do not exceed the following rates, in pound per million British thermal unit (lb/MMBtu) heat input on an annual (calendar year) average:

(A) [(1)] electric power boilers:

(i) [(A)] gas-fired, 0.14;

(ii) [(B)] coal-fired, 0.165;

(B) [(2)] stationary gas turbines (including duct burners used in turbine exhaust ducts):

(i) [(A)] subject to Texas Utilities Code (TUC) [TUC], §39.264 (except units designated in accordance with TUC, §39.264(i)), 0.14;

(ii) [(B)] not subject to TUC, §39.264, 0.15 (or alternatively, 42 parts per million by volume (ppmv) NO_x, adjusted to 15% oxygen (O_2), dry basis [(dry basis)]); and

(iii) [(C)] units designated in accordance with TUC, §39.264(i), 0.15 (or alternatively, 42 ppmv NO_x, adjusted to 15% O_2, dry basis [oxygen (dry basis)]); and [.]

(2) ensure that emissions of carbon monoxide (CO) and ammonia do not exceed the following emission rates from any unit subject to the NO_x emission limits specified in paragraph (1) of this section:

(A) 400 ppmv CO at 3.0% O_2, dry basis (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units and 0.33 lb/MMBtu heat input for coal-fired units), based on:

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

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

(B) ten ppmv ammonia, at 3.0% O_2, dry, for boilers and 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), based on:

(i) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(ii) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia. One of the ammonia monitoring procedures specified in §117.114(a)(4) of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) shall be used to demonstrate compliance with the ammonia emission specification of this subparagraph.

§117.138. System Cap.

(a) (No change.)

(b) Each unit within an electric power generating system, as defined in §117.10(14)(B) [§117.10(13)(B)] of this title (relating to Definitions), that would otherwise be subject to the NO_x emission limits of §117.135 of this title must be included in the system cap.

(c) - (d) (No change.)

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

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

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

(A) (No change.)

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

(4) (No change.)

(f) - (k) (No change.)

§117.141. Initial Demonstration of Compliance.

(a) The owner or operator of all units which are subject to the emission limitations of §117.135 of this title (relating to Emission Specifications) [this division (relating to Utility Electric Generation in East and Central Texas)] must be tested as follows.

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

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

(d) Initial compliance with the emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.143 of this title shall be demonstrated after monitor certification testing using the NO_x CEMS or PEMS as follows. To comply with the NO_x emission limit in pound per million British thermal units (lb/MMBtu) [(MM/Btu)] on an annual average, NO_x emissions from a unit are monitored for each unit operating day in a calendar year, and the annual average emission rate is used to determine compliance with the NO_x emission limit. The annual average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during a calendar year.

§117.143. Continuous Demonstration of Compliance.

(a) (No change.)

(b) Carbon monoxide (CO) monitoring. The owner or operator shall [is not required to] monitor CO exhaust emissions from each unit subject to the emission specifications of this division using one or more of the following methods: [.]

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

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

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

(2) sample CO as follows:

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

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

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

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

(c) - (d) (No change.)

[(e) Auxiliary boilers. The owner or operator of each auxiliary boiler as defined in §117.10 of this title (relating to Definitions) shall:]

[(1) install, calibrate, maintain, and operate a CEMS in accordance with this section; or]

[(2) comply with the appropriate (considering boiler maximum rated capacity and annual heat input) industrial boiler monitoring requirements of §117.213 of this title (relating to Continuous Demonstration of Compliance).]

(e) [(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 §117.135 of this title (relating to Emission Specifications).

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

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

(A) using a CEMS:

(i) in accordance with subsection (c) [(b)] of this section; or

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

(B) using a PEMS.

(3) Any PEMS for units subject to the requirements of 40 CFR 75 shall meet the requirements of 40 CFR 75 Subpart E, §§75.40 - 75.48.

(4) Any PEMS for units not subject to the requirements of 40 CFR 75 shall meet the requirements of either:

(A) 40 CFR 75, Subpart E, §§75.40 - 75.48; or

(B) §117.213(f) of this title (relating to Continuous Demonstration of Compliance).

(f) [(g)] Gas turbine monitoring. The owner or operator of each stationary gas turbine subject to the emission specifications of §117.135 of this title, 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 (relating to Definitions)) which use steam or water injection to comply with the emission specification of §117.135(1)(B) [§117.135(2)] of this title:

(A) install, calibrate, maintain, and operate a CEMS or PEMS in compliance with this section; or

(B) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. The system shall be accurate to within ±5.0%. The steam-to-fuel or water-to-fuel ratio monitoring data shall constitute the method for demonstrating continuous compliance with the emission specification of §117.135(1)(B) [§117.135(2)] of this title; and

(2) for gas turbines not subject to paragraph (1) of this subsection, install, calibrate, maintain, and operate a CEMS or PEMS in compliance with this section.

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

(2) any stationary gas turbine with an MW rating greater than or equal to 1.0 MW operated more than an average of 10% of the hours of the year, averaged over the three most recent calendar years, or more than 20% of the hours in a single calendar year; and

(3) any unit claimed exempt from the emission specifications of this division using the [low annual capacity factor] exemption of §117.133(1) of this title (relating to Exemptions).

(h) [(i)] Run time meters. The owner or operator of any stationary gas turbine using the exemption of §117.133(2) of this title shall record the operating time with an elapsed run time meter approved by the executive director.

(i) [(j)] Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the [low annual capacity factor] exemptions of §117.133 of this title, shall notify the executive director within seven days if the applicable limit is exceeded.

(l) If the limit is exceeded, the exemption from the emission specifications of §117.135 of this title shall be permanently withdrawn.

(2) Within 90 days after loss of the exemption, the owner or operator shall submit a compliance plan detailing a plan to meet the applicable compliance limit as soon as possible, but no

later than 24 months after exceeding the limit. The plan shall include a schedule of increments of progress for the installation of the required control equipment.

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

(j) [(k)] Data used for compliance. After the initial demonstration of compliance required by §117.141 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 this division. Compliance with the emission limitations may also be determined at the discretion of the executive director using any commission compliance method.

(k) [(l)] Enforcement of NO_x limits. No unit subject to §117.135 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117.135 of this title.

§117.149. Notification, Recordkeeping, and Reporting Requirements.

(a) Start-up and shutdown records. For units subject to the start-up and/or shutdown exemptions allowed under §101.222 [§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 fuel burned; gross and net energy production in megawatt-hours (MW-hr); and the date, time, and duration of the event.

(b) - (e) (No change.)

§117.151. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the carbon monoxide (CO) or ammonia limits of §117.135(2) of this title (relating to Emission Specifications), the executive director may approve emission specifications different from the CO or ammonia limits in §117.135(2) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) must determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.135 of this title;

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through system-wide averaging at maximum capacity; and

(4) is the Engineering Services Team, Office of Compliance and Enforcement, for purposes of this section.

(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 or §50.139 of this title (relating to Motion for Reconsideration; and Motion to Overturn Executive Director's Decision) apply. However, only a person affected may file a motion for reconsideration.

DIVISION 3: INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL COMBUSTION SOURCES IN OZONE NONATTAINMENT AREAS
§§117.203, 117.205 - 117.207, 117.213 - 117.216, 117.219, 117.221, 117.223

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

The proposed amendments implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d); and TWC, §5.103.

§117.203. Exemptions.

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

(1) any new units placed into service after November 15, 1992, except for new units which are qualified, at the option of the owner or operator, [were placed into service] as functionally identical replacement for existing units under §117.205(a)(3) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) [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 industrial, commercial, or institutional [, or industrial] boiler or process heater with a maximum rated capacity of less than 40 million Btu per hour (MMBtu/hr);

(3) (No change.)

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

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

(5) (No change.)

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

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

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

(E) - (G) (No change.)

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

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

(A) (No change.)

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

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

(A) (No change.)

(B) meets the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 ([effective] October 23, 1998) and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this paragraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 ([effective] December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account.

(b) (No change.)

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

(a) No person shall allow the discharge of air contaminants into the atmosphere to exceed the emission limits of this section, except as provided in §§117.207, 117.223, or 117.570 of this title (relating to Alternative Plant-wide Emission Specifications; Source Cap; and Use of Emissions Credits for Compliance) [§117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117.223 of this title (relating to Source Cap)].

(1) For purposes of this subchapter, the lower of any permit nitrogen oxides (NO_x) emission limit in effect on June 9, 1993, under a permit issued in accordance with [pursuant to] Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) and the emission limits of subsections (b) - (d) of this section shall apply, except that:

(A) gas-fired boilers and process heaters operating under a permit issued after March 3, 1982, with an emission limit of 0.12 pound NO_x per million British thermal units (lb NO_x/MMBtu) [(Btu)] heat input, shall be limited to that rate for the purposes of this subchapter; and

(B) (No change.)

(2) For purposes of calculating NO_x emission limitations under this section from existing permit limits, the following procedure shall be used:

(A) the limit explicitly stated in lb NO_x/MMBtu [pound NO_x per million Btu (MMBtu)] of heat input by permit provision (converted from low heating value to high heating value, as necessary); or

(B) (No change.)

(3) For any unit placed into service after June 9, 1993 and before the final compliance date as specified in §117.520 of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) [or the final compliance date as approved under the provisions of §117.540 of this title (relating to Phased Reasonably Available Control Technology (RACT)),] as functionally identical replacement for an existing unit or group of

units subject to the provisions of this chapter, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 in accordance with [pursuant to] Chapter 116 of this title and the emission limits of subsections (b) - (d) of this section shall apply. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.207 or §117.223 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

(b) For each boiler and process heater with a maximum rated capacity greater than or equal to 100.0 MMBtu/hr of heat input, the applicable emission limit is as follows:

(1) gas-fired boilers, as follows:

(A) low heat release boilers with no preheated air or preheated air less than 200 degrees Fahrenheit, 0.10 lb [pound (lb)] NO_x/MMBtu of heat input;

(B) - (E) (No change.)

(F) high heat release boilers with preheated air greater than or equal to 500 degrees Fahrenheit, 0.28 lb NO_x/MMBtu of heat input; [.]

(2) gas-fired process heaters, based on either air preheat temperature or firebox temperature, as follows:

(A) based on air preheat temperature:

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

(iii) process heaters with preheated air greater than or equal to 400 degrees Fahrenheit, 0.18 lb NO_x/MMBtu of heat input; [.]

(B) (No change.)

(3) - (6) (No change.)

(7) for units which operate with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.213 of this title (relating to Continuous Demonstration of Compliance), the emission limits shall apply as:

(A) the mass of NO_x emitted per unit of energy input (lb NO_x/MMBtu [pound NO_x per MMBtu]), on a rolling 30-day average period; or

(B) the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in lb NO_x/MMBtu [pound NO_x per MMBtu]; and

(8) (No change.)

(c) - (i) (No change.)

§117.206. Emission Specifications for Attainment Demonstrations.

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

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

(1) gas-fired boilers:

(A) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.020 [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, 0.030 [0.015] lb NO_x per MMBtu; and

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

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

(A) 40 [13] ppmv NO_x at 0.0% O_2, dry basis;

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

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

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

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

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

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

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

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

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

(i) 0.030 lb NO_x per MMBtu; or

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

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

(5) wood fuel-fired boilers, <u>0.060</u> [0.046] lb NO_x per MMBtu;

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

(7) <u>liquid-fired</u> [oil-fired] boilers, 2.0 lb NO_x per 1,000 gallons of <u>liquid</u> [oil] burned;

(8) process heaters:

(A) <u>other than pyrolysis reactors:</u>

<u>(i)</u> with a maximum rated capacity equal to or greater than 100 MMBtu/hr, <u>0.025</u> [0.010] lb NO_x per MMBtu;

(ii) [(B)] with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.025 [0.015] lb NO_x per MMBtu; and

(iii) [(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); and

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

(9) stationary, reciprocating internal combustion engines:

(A) gas-fired rich-burn engines:

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

(ii) all others, 0.50 [0.17] g NO_x/hp-hr;

(B) gas-fired lean-burn engines, except as specified in subparagraph (C) of this paragraph:

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

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

(C) dual-fuel engines:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(10) stationary gas turbines:

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

(B) [(A)] rated at 1.0 MW [megawatt (MW)] or greater, but less than 10 MW, 0.15 [0.015] lb NO_x per MMBtu; and

(C) [(B)] rated at less than 1.0 MW:

(i) with initial start of operation on or before December 31, 2000, 0.26 [0.15] lb NO_x per MMBtu; and

(ii) with initial start of operation after December 31, 2000, 0.26 [0.015] lb NO_x per MMBtu;

(11) duct burners used in turbine exhaust ducts, the corresponding gas turbine emission specification of paragraph (10) of this subsection [0.015 lb NO_x per MMBtu];

(12) pulping liquor recovery furnaces, either:

(A) 0.050 lb NO_x per MMBtu; or

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

(13) kilns:

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

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

(14) metallurgical furnaces:

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

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

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

(16) incinerators, either of the following:

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

(B) 0.030 lb NO_x per MMBtu; and

(17) as an alternative to the emission specifications in paragraphs (1) - (16) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb NO_x per MMBtu. For units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor shall be used to determine whether the unit is eligible for the emission specification of this paragraph.

For units placed into service after January 1, 1997, the annual capacity factor shall be calculated from two consecutive years in the first five years of operation to determine whether the unit is eligible for the emission specification of this paragraph, using the same two consecutive years chosen for the activity level baseline. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title (relating to Definitions). [; and]

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

[(A) gas-fired boilers:]

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

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

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

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

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

[(ii) a 90% NO_x reduction of the exhaust concentration used to calculate the June - August 1997 daily NO_x emissions. To ensure that this emission specification will result in a real 90% reduction in actual emissions, a consistent methodology shall be used to calculate the 90% reduction; or] [(iii) alternatively, for units which did not use a CEMS or PEMS to determine the June - August 1997 exhaust concentration, the owner or operator may:]

[(I) install and certify a NO_x CEMS or PEMS as specified in §117.213(e) or (f) of this title no later than June 30, 2001;]

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

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

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

[(C) BIF units which were regulated as existing facilities by the EPA at 40 CFR Part 266, Subpart H (as was in effect on June 9, 1993):]

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

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

[(I) 0.030 lb NO_x per MMBtu; or]

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

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

[(E) wood fuel-fired boilers, 0.060 lb NO_x per MMBtu;]

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

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

[(H) process heaters:]

[(i) other than pyrolysis reactors:]

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

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

[(III) with a maximum rated capacity less than 40 MMBtu/hr, 0.036 lb NO_x per MMBtu; and]

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

[(I) stationary, reciprocating internal combustion engines:]

[(i) gas-fired rich-burn engines:]

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

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

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

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

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

[(iii) dual-fuel engines:]

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

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

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

[(J) stationary gas turbines:]

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

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

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

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

[(L) pulping liquor recovery furnaces, either:]

[(i) 0.050 lb NO_x per MMBtu; or]

[(ii) 1.08 lb NO_x per ADTP;]

[(M) kilns:]

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

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

[(N) metallurgical furnaces:]

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

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

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

[(P) incinerators, either of the following:]

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

[(ii) 0.030 lb NO_x per MMBtu; and]

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

(d) (No change.)

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

(1) carbon monoxide (CO), 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines; or 775 ppmv at 7.0% O_2, dry basis for wood fuel-fired boilers or process heaters) : [;]

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

(2) ammonia emissions, ten ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), gas-fired lean-burn engines, and lightweight aggregate kilns; 0.0% O_2, dry, for fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents); 7.0% O_2, dry, for BIF units which were regulated as existing facilities by the EPA at 40 CFR Part 266, Subpart H (as was in effect on June 9, 1993), wood-fired boilers, and incinerators; and 3.0% O_2, dry, for all other units, based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

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

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

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

(1) (No change.)

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

(3) changes after December 31, 2000 to [the owner or operator of] a unit subject to an emission specification in subsection (c) of this section (ESAD unit) which result in increased NO_x emissions from a unit not subject to an emission specification in subsection (c) of this section (non-ESAD unit), such as redirecting [, as of December 31, 2000, combusts] one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator with a maximum rated capacity of less than 40 MMBtu/hr or a flare, is only allowed if: [shall not re-direct these streams to flares or other units which are not subject to an emission specification in subsection (c) of this section.]

(A) the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS which meets the requirements of §117.213(e) or (f) of this title, or through stack testing which meets the requirements of §117.211(e) of this title (relating to Initial Demonstration of Compliance); and

(B) a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit is made as specified in §101.354 of this title (relating to Allowance Deductions);

(4) a source which met the definition of major source on December 31, 2000 shall always be classified as a major source for purposes of this chapter. A source which did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2000, but which at any time after December 31, 2000 becomes a major source, shall from that time forward always be classified as a major source for purposes of this chapter; and

(5) the availability under subsection (c)(17) of this section of an emission specification for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. Reduced operation after December 31, 2000 cannot be used to qualify for a more lenient emission specification under subsection (c)(17) of this section than would otherwise apply to the unit.

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

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

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

(3) firewater pumps for emergency response training conducted in the months of April through October.

§117.207. Alternative Plant-wide Emission Specifications.

(a) (No change.)

(b) The owner or operator shall establish an enforceable NO_x [(NO_x)] emission limit for each affected unit at the source as follows.

(1) For boilers and process heaters which operate with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) in accordance with §117.213 of this title (relating to Continuous Demonstration of Compliance), the emission limits shall apply in:

(A) the units of the applicable standard (the mass of NO_x emitted per unit of energy input (pound NO_x per million British thermal units (lb NO_x/MMBtu) [(MM) Btu)] or parts per million by volume (ppmv)), on a rolling 30-day average period; or

(B) (No change.)

(2) (No change.)

(3) For stationary gas turbines, the emission limits shall apply as the NO_x concentration in ppmv [parts per million by volume (ppmv)] at 15% oxygen (O_2), dry basis on a block one-hour average.

(4) (No change.)

(c) - (f) (No change.)

(g) Solely for the purposes of calculating the plant-wide emission limit, the allowable NO_x emission rate (in pounds per hour) for each affected unit shall be calculated from the lowest of the emission specifications of §117.205 of this title, or when applicable, §117.206 of this title, or any applicable permit emission specification identified in subsection (i) of this section, as follows.

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

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

Figure: 30 TAC §117.207(g)(3)

Where:

In-stack NO_x = $NO_x(\text{allowable}) \times (1 - \%H_2O/100) \times \{20.9 - \%O_2/(1 - \%H_2O/100)\}/5.9$

NO_x (allowable) = the applicable NO_x emission specification of §117.205(c) of this title (expressed in ppmv NO_x at 15% O_2, dry basis).

$\%H_2O$ = the volume percent of water in the stack gases, as calculated from the manufacturer's data, or other data as approved by the executive director, at MW rating and ISO flow conditions.

$\%O_2$ = the volume percent of O_2 in the stack gases on a wet basis, as calculated from the manufacturer's data, or other data as approved by the executive director, at MW rating and ISO flow conditions.

(4) (No change.)

(h) (No change.)

(i) When using this section for establishing alternative compliance with §117.206 of this title, the individual NO_x emission limit that is to be used in calculating the alternative plant-wide emission specifications is the lowest of the specification of §117.206 of this title, the actual emission rate as of September 1, 1997, and any applicable permit emission specification:

(1) for units in the Beaumont Port Arthur ozone nonattainment area, in effect on September 10, 1993; or

(2) (No change.)

(j) This section shall no longer apply in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.520(c)(2) of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas). For purposes of this paragraph, this means that the alternative plant-wide emission specifications of this section remain in effect until the emissions allocation for a unit under the Houston/Galveston mass emissions cap are equal to or less than the allocation that would be calculated using the alternative plant-wide emission specifications of this section.

§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)), for stationary gas turbines which are exempt under §117.205(h)(7) of this title, 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) - (iv) (No change.)

(B) (No change.)

(2) (No change.)

(b) (No change.)

(c) NO_x monitors.

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

(A) - (E) (No change.)

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

(G) - (H) (No change.)

(I) fluid catalytic cracking units (including carbon monoxide (CO) boilers, CO furnaces, and catalyst regenerator vents). In addition, the owner or operator shall monitor the stack exhaust flow rate with a flow meter using the flow monitoring specifications of 40 CFR 60, Appendix B, Performance Specification 6 or 40 CFR 75, Appendix A.

(2) (No change.)

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

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

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

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

(A) (No change.)

(B) Appendix B:

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

(ii) - (iii) (No change.)

(C) after [After] the final compliance date or date of required submittal of CEMS performance evaluation, conduct audits in accordance with §5.1 of Appendix F, quality assurance procedures for NO_x, CO and diluent analyzers, except that a cylinder gas audit or relative accuracy audit may be performed in lieu of the annual relative accuracy test audit (RATA) required in §5.1.1. However, if the optional alternative relative accuracy requirement of subparagraph (B)(i) of this paragraph (or equivalent) from the reference method mean value is used, then an annual RATA must be performed.

(2) (No change.)

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

(A) (No change.)

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

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

(A) all bypass stacks shall be monitored in order to quantify emissions directed through the bypass stack;

(B) one CEMS may be shared among units, provided:

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

(ii) the CEMS meets the certification requirements of paragraph (1) of this subsection for each stack while the CEMS is operating in the time-shared mode; and

(C) exhaust streams of units which vent to a common stack do not need to be analyzed separately.

(5) As an alternative to paragraph (1) of this subsection, an owner or operator may choose to comply with the CEMS requirements of 40 CFR Part 75 as follows:

(A) general operation requirements in Subpart B, §75.10(a)(2);

(B) certification procedures and test methods in Subpart C, §75.20(c) and §75.22;

(C) recordkeeping requirements of the monitoring plan in Subpart D, §75.53(a) - (c);

(D) appropriate specifications and test procedures in Appendix A, as follows:

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

(ii) Section 2 (Equipment Specifications);

(iii) Section 3 (Performance Specifications);

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

(v) Section 5 (Calibration Gas);

(vi) Section 6 (Certification Tests and Procedures); and

(vii) meet either the relative accuracy requirement of 40 CFR Part 75 in percentage only, or the alternative relatively accuracy requirement of $\pm$ 2.0 ppmv from the reference method mean value; and

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

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

(ii) Section 2 (Frequency of Testing).

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

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

(1) - (4) (No change.)

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

(A) perform the following alternative initial certification tests:

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

(I) Performance Specification 2, subsection 4.3 (pertaining to NO_x) in terms of the applicable standard (in ppmv, lb/MMBtu, or g/hp-hr). An alternative relative accuracy requirement of $\pm$ 2.0 ppmv from the reference method mean value is allowed;

(II) - (III) (No change.)

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

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

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

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

(IV) waivers from the statistical tests and default reference method standard deviation values for the F-test shall be allowed according to the "TNRCC PEMS Protocol Draft," May 16, 1994;

(V) the correlation analysis may only be temporarily waived following review of the waiver request submittal if:

(-a-) the process design is such that it is technically impossible to vary the process to result in a concentration change sufficient to allow a successful correlation analysis statistical test. Any waiver request must also be accompanied with documentation of the reference method measured concentration, and documentation that it is less than 50% of the emission limit or standard. The waiver is to be based on the measured value at the time of the waiver. Should a subsequent RATA effort identify a change in the reference method measured value by more than 30%, the statistical test must be repeated at the next RATA effort to verify the successful compliance with the correlation analysis statistical test requirement; or

(-b-) the data for a measured compound (e.g., NO_x, O_2) are determined to be autocorrelated according to the procedures of 40 CFR §75.41(b)(2). A complete analysis of autocorrelation with support information shall be submitted with the request for waiver. The statistical test shall be repeated at the next RATA effort to verify the successful compliance with the correlation analysis statistical test requirement; and

(VI) all requests for waivers shall be submitted to the Engineering Services Team, Office of Compliance and Enforcement for review. The manager of the Engineering Services Team shall approve or deny each waiver request;

(B) (No change.)

(C) after the final compliance date, perform RATA for each unit:

(i) (No change.)

(ii) using the Performance Specifications of <u>subparagraph (A)(i)(I) - (III) of this paragraph</u> [paragraph (5)(A)(i)(I) - (III) of this subsection]; and

(iii) at the following frequency:

(I) (No change.)

(II) annually, if following the first semiannual RATA, the relative accuracy during the previous audit for each compound monitored by PEMS is less than or equal to 7.5% <u>(or within ± 2.0 ppmv)</u> of the mean value of the reference method test data at normal load operation; or alternatively,

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

(6) - (7) (No change.)

(g) Engine monitoring. The owner or operator of any stationary gas engine subject to the emission specifications of this division shall stack test engine NO_x and CO emissions as follows.

(1) Engines not using NO_x CEMS or PEMS.

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

(C) <u>Engines used exclusively in emergency situations</u> [Gas-fired emergency generators] are not required to conduct the testing specified in subparagraph (B) of this paragraph.

(2) (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) (No change.)

(2) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption<u>:</u> [.]

(A) the [The] system shall be accurate to within ± 5.0%; [.]

(B) the [The] steam-to-fuel or water-to-fuel ratio monitoring data shall constitute the method for demonstrating continuous compliance with the applicable emission specification of §117.205 or §117.207 of this title; and [.]

(C) steam [Steam] or water injection control algorithms are subject to executive director approval.

(i) Run time meters. The owner or operator of any stationary gas turbine or stationary internal combustion engine claimed exempt using the exemption of §117.205(h)(2) or (9) or §117.203(a)(6)(D), (11), or (12) of this title shall record the operating time with an elapsed run time meter. Any run time meter installed on or after October 1, 2001 shall be non-resettable.

(j) Hydrogen (H_2) monitoring. The owner or operator claiming the H_2 multiplier of §117.205(b)(6) or [,] §117.207(g)(4) [,] or (h) of this title shall sample, analyze, and record every three hours the fuel gas composition to determine the volume percent H_2.

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

(k) - (l) (No change.)

(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 (relating to Definitions), as appropriate, is exceeded.

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

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

(a) Monitoring requirements.

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

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

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

(i) Mass balance. Calculate ammonia emissions as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of the control device which injects urea or ammonia into the exhaust stream. The equation is: ammonia parts per million by volume (ppmv) at reference oxygen = $\{(a/b)(10^6) - c\}(d)$, where reference oxygen on a dry basis is 3.0% for boilers and process heaters, 0.0% for fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents), 7.0% for boilers and industrial furnaces (BIF units) which were regulated as existing facilities by the EPA at 40 Code of Federal Regulations Part 266, Subpart H (as was in effect on June 9, 1993), wood-fired boilers, and incinerators, 15% for stationary gas turbines (including duct burners used in turbine exhaust ducts), gas-fired lean-burn engines, and lightweight aggregate kilns, and 3.0% for all other units; a = ammonia injection rate (in pounds per hour (lb/hr))/17 pound per pound-mole (lb/lb-mol); b = dry exhaust flow rate (lb/hr)/29 lb/lb-mol; c = change in measured NO_x concentration across catalyst (ppmv at reference oxygen); and d = correction factor, the ratio of measured slip to calculated ammonia slip, where the measured slip is obtained from the stack sampling for ammonia required by §117.211(a)(2) of this title (relating to Initial Demonstration of Compliance), using either the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method 27.

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

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

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

(2) (No change.)

(b) Testing and operating requirements.

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

(2) Each stationary internal combustion engine which is not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) shall be checked for proper operation of the engine by recorded measurements of NO_x and CO emissions at least

quarterly and as soon as practicable within two weeks after each occurrence of engine maintenance which may reasonably be expected to increase emissions, oxygen (O_2) sensor replacement, or catalyst cleaning or catalyst replacement. Stain tube indicators specifically designed to measure NO_x concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x analyzers shall also be acceptable for this documentation. Quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours. This exemption does not diminish the requirement to test emissions after the installation of controls, major repair work, and any time the owner or operator believes emissions may have changed.

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

(c) Emission allowances.

(1) (No change.)

(2) For units not operating with CEMS [continuous emissions monitoring system (CEMS)] or PEMS [predictive emissions monitoring system (PEMS)], the following apply.

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

(C) The NO_x emission rate determined by the retesting shall establish a new emission factor to be used to calculate actual emissions from the date of the retesting forward. Until the date of the retesting, [instead of] the previously determined emission factor shall be used to calculate actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(D) All test reports must be submitted to the executive director for review and approval within 60 days after completion of the testing.

(3) (No change.)

§117.215. Final Control Plan Procedures for Reasonably Available Control Technology.

(a) The owner or operator of units listed in §117.201 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)). The report must include a list of the units listed in §117.201 of this title, showing:

(1) (No change.)

(2) the section under which NO_x compliance is being established for units specified in paragraph (1) of this subsection, either:

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

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

(3) - (5) (No change.)

(6) the specific rule citation for any unit with a claimed exemption from the emission specifications of this division, for:

(A) boilers and heaters with a maximum rated capacity greater than or equal to 100.0 million British thermal units [Btu] per hour (MMBtu/hr);

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

(b) (No change.)

(c) For sources complying with §117.223 of this title [(relating to Source Cap)], in addition to the requirements of subsection (a) of this section, the owner or operator shall submit:

(1) - (4) (No change.)

(d) (No change.)

(e) The report must be submitted by the applicable date specified for final control plans in §117.520 of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) [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 an emission limit on a rolling 30-day average, according to the applicable schedule given in §117.520 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 [§117.206(a) and (b)] of this title (relating to Emission Specifications for Attainment Demonstrations) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.206 of this title. The report must include:

(1) the section under which NO_x compliance is being established, either:

(A) §117.206 [Section 117.206] of this title;

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

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

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

(E) Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program); and, where applicable, §117.210 of this title (relating to System Cap);

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

(4) the submittal date, and whether sent to the central [Austin] or the regional office (or both), of any compliance stack test report or relative accuracy test audit report required by §117.211 of this title which is not being submitted concurrently with the final compliance report; [and]

(5) the specific rule citation for any unit with a claimed exemption from the emission specification of §117.206 of this title; and [.]

(6) for sources complying with §117.210 of this title, in addition to the requirements of paragraphs (1) - (5) of this subsection, the owner or operator shall submit:

(A) the calculations used to calculate the 30-day average and maximum daily system cap allowable emission rates;

(B) a list containing, for each unit in the cap:

(i) the average daily heat input H_i specified in §117.210(c)(1) and (2) of this title;

(ii) the maximum daily heat input H_{mi} specified in §117.210(c)(3) of this title;

(iii) the method of monitoring emissions; and

(iv) the method of providing substitute emissions data when the NO_x monitoring system is not providing valid data; and

(C) an explanation of the basis of the values of H_i and H_{mi}.

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

§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 §101.222 [§101.11] of this title (relating to Demonstrations), hourly records shall be made of start-up and/or shutdown events and maintained for a period of at least two years. Records shall be available for inspection by the executive director, EPA, and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type of fuel burned; and the date, time, and duration of the procedure.

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

(1) verbal notification of the date of any [initial demonstration of compliance] testing conducted under §117.211 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) (No change.)

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

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

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system under §117.213 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations of this division (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) and the monitoring system performance. For sources in the Houston/Galveston ozone nonattainment area in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), which are no longer subject to the emission limitations of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), the report is only a monitoring system report as specified in paragraph (3) of this subsection. All reports shall be postmarked or received by the 30th day following the end of each calendar semiannual period. Written reports shall include the following information:

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

(A) for [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; and [.]

(B) for [For] units complying with §117.223 of this title (relating to Source Cap), excess emissions are each daily period for which the total nitrogen oxides (NO_x) emissions exceed the rolling 30-day average or the maximum daily NO_x cap; [.]

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

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

(5) (No change.)

(e) Reporting for engines. The owner or operator of any gas-fired [rich-burn] engine subject to the emission limitations in §§117.205, 117.206 (relating to Emission Specifications for Attainment Demonstrations), or 117.207 (relating to Alternative Plant-wide Emission Specifications) of this title shall report in writing to the executive director on a semiannual [quarterly] basis any excess emissions and the air-fuel ratio monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar semiannual period. Written reports shall include the following information:

(1) the magnitude of excess emissions (based on the quarterly emission checks of §117.208(d)(7) of this title (relating to Operating Requirements) and the biennial emission testing required for demonstration of emissions compliance in accordance with §117.213(g) of this title, computed in pounds per hour and grams per horsepower-hour, any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the engine operating time during the reporting period; and

(2) (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) - (6) (No change.)

(7) records [Records] of carbon monoxide measurements specified in §117.213(d)(2) of this title;

(8) - (10) (No change.)

§117.221. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or the carbon monoxide (CO) or ammonia limits of §117.206(e) of this title (relating to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.205 of this title or the CO or ammonia limits in §117.206(e) of this title for that unit. The executive director:

(1) (No change.)

(2) must determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.205 or §117.206 of this title, as applicable; [reasonably available control technology; and]

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through plant-wide averaging at maximum capacity; and [.]

(4) is the Engineering Services Team, Office of Compliance and Enforcement, for purposes of this section.

(b) (No change.)

§117.223. Source Cap.

(a) (No change.)

(b) The source cap allowable mass emission rate shall be calculated as follows.

(1) A rolling 30-day average emission cap shall be calculated for all emission units included in the source cap using the following equation. [:]

Figure: 30 TAC §117.223(b)(1)

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

Where:

i = each emission unit in the emission cap

N = the total number of emission units in the emission cap

H_i = (A) For compliance with §117.205(a) - (d) of this title. The actual historical average of the daily heat input for each unit included in the source cap, in million (MM) Btu per day, as certified to the executive director, for a 24 consecutive month period between January 1, 1990 and June 9, 1993, plus one standard deviation of the average daily heat input for that period. All sources included in the source cap shall use the same 24 consecutive month period. If sufficient historical data are not available for this calculation, the executive director may approve another method for calculating H_i.

(B) For compliance with §117.205(e) or §117.206 of this title. The actual historical average of the daily heat input for each unit included in the source cap, in MMBtu per day, as certified to the executive director, for a 24 consecutive month period between January 1, 1997 and December 31, 1999. All sources included in the source cap shall use the same 24 consecutive month period. If sufficient historical data are not available for this calculation, the executive director and EPA may approve another method for calculating H_i. For sources in the Beaumont/Port Arthur ozone nonattainment area complying with the lean-burn engine emission specifications in §117.205(e) of this title, the owner or operator may combine the source cap with sources complying with §117.205(a) - (d) of this title, using the 1997 - 1999 heat input baseline described earlier for the sources complying with §117.205(a) - (d) of this title.

R_i = (A) For compliance with §117.205(a) - (d) of this title.

(i) For emission units subject to the federal New Source Review (NSR) requirements of 40 Code of Federal Regulations (CFR) 51.165(a), 40 CFR 51.166, or 40 CFR 52.21, or to the requirements of Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) which implements these federal requirements, or emission units that have been subject to a New Source Performance Standard requirement of 40 CFR 60 prior to June 9, 1993, R_i is the lowest of the actual emission rate or all applicable federally enforceable emission limitations as of June 9, 1993, in pounds (lb) NO_x per MMBtu, that apply to emission unit *I* in the absence of trading. All calculations of emission rates shall presume that emission controls in effect on June 9, 1993 are in effect for the two-year period used in calculating the actual heat input.

(ii) For all other emission units, R_i is the lowest of the reasonably available control technology (RACT) limit of §117.205(b) - (d) or §117.207(f) of this title or the best available control technology limit for any unit subject to a permit issued in accordance with [pursuant to] Chapter 116 of this title, in lb NO_x/MMBtu, that applies to emission unit *I* in the absence of trading.

(B) For compliance with §117.205(e) or §117.206 of this title, the lowest of:

(i) the appropriate limit of §§117.205(e), 117.206, or 117.207(f) of this title;

(ii) any permit emission limit for any unit subject to a permit issued in accordance with [pursuant to] Chapter 116 of this title, in lb NO_x/MMBtu, that applies to emission unit *I* in the absence of trading, in the:

(I) Beaumont Port Arthur ozone nonattainment area, in effect on September 10, 1993; and

(II) Dallas/Fort Worth ozone nonattainment area, in effect on September 1, 1997; and

(iii) the actual emission rate as of the dates specified in clause (ii) of this subparagraph. All calculations of emission rates shall presume that emission controls in effect on the dates specified in clause (ii) of this subparagraph are in effect for the two-year period used in calculating the actual heat input.

(2) A maximum daily cap shall be calculated for all emission units included in the source cap using the following equation. [:]

Figure: 30 TAC §117.223(b)(2) (No change.)

(3) (No change.)

(4) The owner or operator at its option may include any of the entire classes of exempted units listed in §117.207(f) of this title in a source cap. For compliance with §117.205(a) - (d) of this title, such units shall be required to reduce emissions available for use in the cap by an additional amount calculated in accordance with the EPA's [United States Environmental Protection Agency's] proposed Economic Incentive Program rules for offset ratios for trades between RACT and non-RACT sources, as published in the February 23, 1993, *Federal Register* (58 FR 11110).

(5) - (6) (No change.)

(c) The owner or operator who elects to comply with this section shall:

(1) for each unit included in the source cap, either:

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

(2) For each operating unit equipped with CEMS, the owner or operator shall either use a PEMS in accordance with [pursuant] to §117.213 of this title, or the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117.211(e) of this title, to provide emissions compliance data during periods when the CEMS is off-line. The methods specified in 40 Code of Federal Regulations §75.46 [CFR 75.46] shall be used to provide emissions substitution data for units equipped with PEMS.

(d) - (f) (No change.)

(g) For compliance with §117.205(a) - (d) of this title by November 15, 1999, a unit which has operated since November 15, 1990, and has since been permanently retired or decommissioned and rendered inoperable prior to June 9, 1993, may be included in the source cap emission limit under the following conditions.

(1) The [the] unit shall have actually operated since November 15, 1990. [;]

(2) For [for] purposes of calculating the source cap emission limit, the applicable emission limit for retired units shall be calculated in accordance with subsection (b) of this section. [;]

(3) (No change.)

(4) The [the] owner or operator shall certify the unit's operational level and maximum rated capacity. [; and]

(5) Emission [emission] reductions from shutdowns or curtailments which have not been used for netting or offset purposes under the requirements of Chapter 116 of this title or have not resulted from any other state or federal requirement may be included in the baseline for establishing the cap.

(h) For compliance with §117.205(e) or §117.206 of this title, a unit which has been permanently retired or decommissioned and rendered inoperable may be included in the source cap under the following conditions. [:]

(1) Shutdowns [shutdowns] must have occurred after the following dates:

(A) September 10, 1993, in the Beaumont/Port Arthur ozone nonattainment area; and [.]

(B) (No change.)

(2) The [the] source cap emission limit for retired units is calculated in accordance with subsection (b) of this section. [;]

(3) (No change.)

(4) The [the] owner or operator shall certify the unit's operational level and maximum rated capacity. [; and]

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

(i) - (k) (No change.)

(l) This section shall no longer apply in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.520(c)(2) of this title. For purposes of this paragraph, this means that the system cap of this section remains in effect until the emissions allocation for a unit under the Houston/Galveston mass emissions cap are equal to or less than the allocation that would be calculated using the system cap of this section.

SUBCHAPTER C: ACID MANUFACTURING
DIVISION 1: ADIPIC ACID MANUFACTURING
§§117.301, 117.309, 117.311, 117.313, 117.319, 117.321

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

The proposed amendments implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d); and TWC, §5.103.

§117.301. Applicability.

The provisions of this <u>division (relating to Adipic Acid Manufacturing)</u> [undesignated head concerning Adipic Acid Manufacturing] shall apply only in the [following areas designated nonattainment for ozone:] Beaumont/Port Arthur and Houston/Galveston <u>ozone nonattainment areas</u>. These provisions shall apply to each adipic acid production unit which is the affected facility.

§117.309. Control Plan Procedures.

Any person affected by this <u>division (relating to Adipic Acid Manufacturing)</u> [undesignated head concerning Adipic Acid Manufacturing] shall submit a control plan to the executive director on the compliance status of all required emission controls and monitoring systems by April 1, 1994. The executive director shall approve the plan if it contains all the information specified in this section. Revisions to the control plan shall be submitted to the executive director for approval. The control plan shall provide a detailed description of the method to be followed to achieve compliance, specifying the anticipated dates by which the following steps will be taken:

(1) - (4) (No change.)

§117.311. Initial Demonstration of Compliance.

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

(d) Testing conducted before June 23, 1994 [prior to the effective date of this rule] may be used to demonstrate compliance with the standard specified in §117.305 of this title if the owner or operator of an affected facility demonstrates to the executive director that the prior performance testing at least meets the requirements of subsections (a) - (c) of this section. The executive director reserves the right to request performance testing or CEMS or PEMS performance evaluation at any time.

§117.313. Continuous Demonstration of Compliance.

(a) The owner or operator of any facility subject to the provisions of this division (relating to Adipic Acid Manufacturing) [undesignated head concerning Adipic Acid Manufacturing] shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring nitrogen oxides (NO_x) from the absorber.

(b) (No change.)

(c) As an alternative to CEMS, the owner or operator of units subject to continuous monitoring requirements under this division [undesignated head] may, with the approval of the executive director, elect to install, calibrate, maintain, and operate a predictive emissions monitoring system (PEMS). The required PEMS shall be used to measure NO_x emissions for each affected unit and shall be used to demonstrate continuous compliance with the emission limitations of §117.305 of this title (relating to Emission Specifications). Any PEMS shall meet the requirements of §117.319 of this title (relating to Notification, Recordkeeping, and Reporting Requirements) and §117.213(f) [§117.213(c)(1)-(3)] of this title (relating to Continuous Demonstration of Compliance).

(d) (No change.)

(e) After the initial demonstration of compliance required by §117.311 of this title (relating to Initial Demonstration of Compliance), compliance with §117.305 of this title [(relating to Emission Specifications)] shall be determined by the methods required in this section. Compliance with the emission limitations may also be determined at the discretion of the executive director using any commission [Texas Natural Resource Conservation Commission] compliance method.

§117.319. Notification, Recordkeeping, and Reporting Requirements.

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

(c) The owner or operator of an affected facility shall report in writing to the executive director on a quarterly basis all periods of excess emissions, defined as any 24-hour period during which the average nitrogen oxides (NO_x) emissions (arithmetic average of 24 contiguous one-hour periods) exceed the emission limitation in §117.305 of this title (relating to Emission Specifications) and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information:

(1) - (4) (No change.)

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

(d) The owner or operator of an affected facility shall maintain written records of all continuous emissions monitoring and performance test results, hours of operation, and daily production rates. Such records shall be kept for a period of at least five [two] years and shall be made available upon request by authorized representatives of the executive director, EPA [TNRCC, United States Environmental Protection Agency], or local air pollution control agencies having jurisdiction.

§117.321. Alternative Case Specific Specifications.

Where a person can demonstrate that an affected unit cannot attain the requirements of §117.305 of this title (relating to Emission Specifications), as applicable, the executive director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117.305 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides emission specifications of §117.305 of this title [reasonably available control technology]. Any person affected by the decision of the executive director may appeal to the commission by filing written notice of appeal with the executive director within 30 days after the decision. Such appeal is to be taken by written notification to the executive director. The requirements of §50.39 or §50.139 of this title (relating to Motion for Reconsideration; and Motion to Overturn Executive Director's Decision) apply. [Section 103.71 of this title (relating to Request for Action by the Commission) should be consulted for the method of requesting commission action on the appeal.] 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 [undesignated head] (relating to Adipic Acid Manufacturing).

DIVISION 2: NITRIC ACID MANUFACTURING - OZONE NONATTAINMENT AREAS
§§117.401, 117.409, 117.411, 117.413, 117.419, 117.421

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

The proposed amendments implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d); and TWC, §5.103.

§117.401. Applicability.

The provisions of this division (relating to Nitric Acid Manufacturing - Ozone Nonattainment Areas) [undesignated head concerning Nitric Acid Manufacturing] shall apply only in the [following areas designated nonattainment for ozone:] Beaumont/Port Arthur and Houston/Galveston ozone nonattainment areas. These provisions shall apply to each nitric acid production unit which is the affected facility.

§117.409. Control Plan Procedures.

Any person affected by this division (relating to Nitric Acid Manufacturing - Ozone Nonattainment Areas) [undesignated head concerning Nitric Acid Manufacturing] shall submit a control plan to the executive director on the compliance status of all required emission controls and monitoring systems by April 1, 1994. The executive director shall approve the plan if it contains all the information specified in this section. Revisions to the control plan shall be submitted to the executive director for approval. The control plan shall provide a detailed description of the method to be followed to achieve compliance, specifying the anticipated dates by which the following steps will be taken:

(1) - (4) (No change.)

§117.411. Initial Demonstration of Compliance.

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

(d) Testing conducted before June 23, 1994 [prior to the effective date of this rule] may be used to demonstrate compliance with the standard specified in §117.405 of this title if the owner or operator of an affected facility demonstrates to the executive director that the prior performance testing at least meets the requirements of subsections (a) - (c) of this section. The executive director reserves the right to request performance testing or CEMS or PEMS performance evaluation at any time.

§117.413. Continuous Demonstration of Compliance.

(a) The owner or operator of any facility subject to the provisions of this division (relating to Nitric Acid Manufacturing - Ozone Nonattainment Areas) [undesignated head concerning Nitric Acid Manufacturing] shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring nitrogen oxides (NO_x) from the absorber.

(b) (No change.)

(c) As an alternative to CEMS, the owner or operator of units subject to continuous monitoring requirements under this division [undesignated head] may, with the approval of the executive director, elect to install, calibrate, maintain, and operate a predictive emissions monitoring system (PEMS). The required PEMS shall be used to measure NO_x emissions for each affected unit and shall be used to demonstrate continuous compliance with the emission limitations of §117.405 of this title (relating to Emission Specifications). Any PEMS shall meet the requirements of §117.419 of this title (relating to Notification, Recordkeeping, and Reporting Requirements) and §117.213(f) [§117.213(c)(1)-(3)] of this title (relating to Continuous Demonstration of Compliance).

(d) (No change.)

(e) After the initial demonstration of compliance required by §117.411 of this title (relating to Initial Demonstration of Compliance), compliance with §117.405 of this title (relating to Emission Specifications) shall be determined by the methods required in this section. Compliance with the emission limitations may also be determined at the discretion of the executive director using any commission [Texas Natural Resource Conservation Commission] compliance method.

§117.419. Notification, Recordkeeping, and Reporting Requirements.

(a) (No change.)

(b) The owner or operator of an affected facility shall furnish the executive director and any local air pollution control agency having jurisdiction a copy of any CEMS or PEMS performance evaluation conducted under §117.413 of this title [(relating to Continuous Demonstration of Compliance)], or any initial demonstration of compliance testing conducted under §117.411 of this title [(relating to Initial Demonstration of Compliance)], within 60 days after completion of such evaluation or testing. For purposes of demonstrating compliance with §117.530 of this title (relating to Compliance Schedules for Nitric Acid and Adipic Acid Manufacturing Sources), such results shall be submitted no later than 30 days before the final compliance date specified in §117.530 of this title.

(c) The owner or operator of an affected facility shall report in writing to the executive director on a quarterly basis all periods of excess emissions, defined as any 24-hour period during which the average nitrogen oxides emissions (arithmetic average of 24 contiguous one-hour periods) as measured by a CEMS or PEMS exceed the emission limitation in §117.405 of this title (relating to Emission Specifications) and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. Written reports shall include the following information:

(1) - (4) (No change.)

(5) if the total duration of excess emissions for the reporting period is less than 1.0% of the total operating time for the reporting period and the CEMS or PEMS downtime for the reporting period is less than 5.0% of the total operating time for the reporting period, only a summary report form (as outlined in the latest edition of the <u>commission's</u> [Texas Natural Resource Conservation Commission (TNRCC)] "Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports") shall be submitted, unless otherwise requested by the executive director [of the TNRCC]. If the total duration of excess emissions for the reporting period is greater than or equal to 1.0% of the total operating time for the reporting period or the CEMS or PEMS downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(d) The owner or operator of an affected facility shall maintain written records of all continuous emissions monitoring and performance test results, hours of operation, and daily production rates. Such records shall be kept for a period of at least <u>five</u> [two] years and shall be made available upon request by authorized representatives of the <u>executive director, EPA</u> [TNRCC, United States Environmental Protection Agency], or any local air pollution control agency having jurisdiction.

§117.421. Alternative Case Specific Specifications.

Where a person can demonstrate that an affected unit cannot attain the requirements of §117.405 of this title (relating to Emission Specifications), as applicable, the executive director, on a case-by-case basis after considering the technological and economic circumstances of the individual unit, may approve emission specifications different from §117.405 of this title for that unit based on the determination that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of <u>controls to meet the nitrogen oxides emission specifications of §117.405 of this title</u> [reasonably available control technology]. Any person affected by the decision of the executive director may appeal to the commission by filing written notice of appeal with the executive director within 30 days after the decision. Such appeal is to be taken by written notification to the executive director. <u>The requirements of §50.39 or §50.139 of this title (relating to Motion for</u>

Reconsideration; and Motion to Overturn Executive Director's Decision) apply. [Section 103.71 of this title (relating to Request for Action by the Commission) should be consulted for the method of requesting commission action on the appeal.] 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 [undesignated head] (relating to Nitric Acid Manufacturing - Ozone Nonattainment Areas).

SUBCHAPTER D: SMALL COMBUSTION SOURCES
DIVISION 1: WATER HEATERS, SMALL BOILERS, AND PROCESS HEATERS
§§117.463, 117.465, 117.467

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

The proposed amendments implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d); and TWC, §5.103.

§117.463. Exemptions.

This division (relating to Water Heaters, Small Boilers, and Process Heaters) does not apply to:

(1) (No change.)

(2) units used in recreational vehicles; [and]

(3) Type 0 units used exclusively to heat swimming pools and hot tubs; [.]

(4) units manufactured in Texas for shipment and use outside of Texas; and

(5) units which do not comply with the nitrogen oxides (NO_x) limits specified in §117.465 of this title (relating to Emission Specifications) that are sold, supplied, or offered for sale in Texas, provided that the manufacturer or distributor can demonstrate that the units are intended for shipment and use outside of Texas, and that the manufacturer or distributor has taken reasonable prudent precautions to assure that the units are not distributed for sale in Texas. This paragraph does not apply to units that are sold, supplied, or offered for sale by any person to retail outlets in Texas.

§117.465. Emission Specifications.

Natural gas-fired Type 0, 1, and 2 units sold, distributed, installed, or offered for sale within the State of Texas shall meet the following limits for nitrogen oxides (NO_x, calculated as nitrogen dioxide (NO_2)).

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

(4) Type 2 units manufactured on or after July 1, 2002 shall not exceed:

(A) (No change.)

(B) 0.037 pound per million British thermal units <u>(lb/MMBtu)</u> [per hour (MMBtu/hr)] of heat input.

§117.467. Certification Requirements.

(a) The manufacturer shall demonstrate that each model of Type 0, 1, and 2 unit subject to the requirements of §117.465 of this title (relating to Emission Specifications) has been tested in accordance with Test Method 7 (40 Code of Federal Regulations 60, Appendix A ([effective] June 11, 1986)), including 7A-E, and the South Coast Air <u>Quality</u> Management District (SCAQMD) Protocol: *Nitrogen Oxides Emissions Compliance Testing for Natural Gas-Fired Water Heaters and Small Boilers* (January 1998).

(b) (No change.)

DIVISION 2: BOILERS, PROCESS HEATERS, AND STATIONARY ENGINES AND GAS TURBINES AT MINOR SOURCES
§§117.473, 117.475, 117.478, 117.479, 117.481

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

The proposed amendments and new section implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d); and TWC, §5.103.

§117.473. Exemptions.

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

(1) (No change.)

(2) the following stationary engines:

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

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

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

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

(i) (No change.)

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

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

(i) (No change.)

(ii) meet the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 ([effective] October 23, 1998) and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 ([effective] December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

(3) (No change.)

(b) (No change.)

§117.475. Emission Specifications.

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

(c) The following NO_x emission specifications shall be used in conjunction with subsection (a) of this section to determine allocations for Chapter 101, Subchapter H, Division 3 of this title, or in conjunction with subsection (b) of this section to establish unit-by-unit emission specifications, as appropriate:

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

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

(A) placed into service before October 1, 2001 which have not been modified, reconstructed, or relocated on or after October 1, 2001, the lower of 11.0 g/hp-hr or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data. For the purposes of this paragraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations §60.15 ([effective] December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account; and

(B) (No change.)

(5) (No change.)

(6) as an alternative to the emission specifications in paragraphs (1) - (5) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu heat input. For units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor shall be used to determine whether the unit is eligible for the emission specification of this paragraph. For units placed into service after January 1, 1997, the annual capacity factor shall be calculated from two consecutive years in the first five years of operation to determine whether the unit is eligible for the emission specification of this paragraph, using the same two consecutive years chosen for the activity level baseline. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title (relating to Definitions).

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

(f) Changes after December 31, 2000 to [The owner or operator of] a unit subject to an emission specification in subsection (c) of this section (ESAD unit) which result in increased NO_x emissions from a unit not subject to an emission specification in subsection (c) of this section (non-ESAD unit), such as redirecting [, as of December 31, 2000, combusts] one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator with a maximum rated capacity of less than 40 MMBtu/hr or a flare, is only allowed if: [shall not re-direct these streams to flares or other units which are not subject to an emission specification in subsection (c) of this section.]

(1) the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS which meets the requirements of §117.479(c) of this title, or through stack testing which meets the requirements of §117.479(e) of this title; and

(2) either of the following conditions is met:

(A) for sources which are subject to Chapter 101, Subchapter H, Division 3 of this title, a deduction in allowances equal to the increase in NO_x emissions at the non-ESAD unit is made as specified in §101.354 of this title (relating to Allowance Deductions); or

(B) for sources which are not subject to Chapter 101, Subchapter H, Division 3 of this title, emission credits equal to the increase in NO_x emissions at the non-ESAD unit are obtained and used in accordance with §117.570 of this title (relating to Use of Emissions Credits for Compliance).

(g) A source which met the definition of major source on December 31, 2000 shall always be classified as a major source for purposes of this chapter. A source which did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2000, but which at any time after December 31, 2000 becomes a major source, shall from that time forward always be classified as a major source for purposes of this chapter.

(h) The availability under subsection (c)(6) of this section of an emission specification for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. Reduced operation after December 31, 2000 cannot be used to qualify for a more lenient emission specification under subsection (c)(6) of this section than would otherwise apply to the unit.

(i) No person shall allow the discharge into the atmosphere from any unit subject to NO_x emission specifications in subsection (c) of this section, emissions in excess of the following, except as provided in §117.481 of this title (relating to Alternative Case Specific Specifications):

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

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

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

(2) ammonia emissions, ten ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts) and gas-fired lean-burn engines; and 3.0% O_2, dry, for all other units, based on:

(A) a block one-hour averaging period for units not equipped with a CEMS or PEMS for ammonia; or

(B) a rolling 24-hour averaging period for units equipped with CEMS or PEMS for ammonia.

§117.478. Operating Requirements.

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

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

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

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

(3) firewater pumps for emergency response training conducted in the months of April through October.

§117.479. Monitoring, Recordkeeping, and Reporting Requirements.

(a) - (d) (No change.)

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

(1) (No change.)

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

(3) - (6) (No change.)

(7) For units not operating with CEMS or PEMS, the following apply.

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

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

(8) (No change.)

(9) All test reports must be submitted to the executive director for review and approval within 60 days after completion of the testing.

(f) (No change.)

(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) - (3) (No change.)

(4) records of CO [carbon monoxide] measurements specified in §117.478(b)(5) of this title;

(5) - (6) (No change.)

(h) - (j) (No change.)

§117.481. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the carbon monoxide (CO) or ammonia limits of §117.475(i) of this title (relating to Emission Specifications), the executive director may approve emission specifications different from the CO or ammonia limits in §117.475(i) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) must determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of controls to meet the nitrogen oxides (NO_x) emission specifications of §117.475 of this title;

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through system-wide averaging at maximum capacity; and

(4) is the Engineering Services Team, Office of Compliance and Enforcement, for purposes of this section.

(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 or §50.139 of this title (relating to Motion for Reconsideration; and Motion to Overturn Executive Director's Decision) apply. However, only a person affected may file a motion for reconsideration.

SUBCHAPTER E: ADMINISTRATIVE PROVISIONS
§§117.510, 117.512, 117.520, 117.534

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

The proposed amendments implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d); and TWC, §5.103.

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

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

(1) (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) - (B) (No change.)

<u>(C) May 1, 2003, install CEMS or PEMS on previously exempt units and conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.113 of this title;</u>

(D) [(C)] July 31, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap to comply with subparagraph (A) of this paragraph;

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

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

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

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

(iii) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.106(a) of this title; and

(G) [(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) (No change.)

(2) Emission specifications for attainment demonstration.

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

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

(iii) May 1, 2003, install CEMS or PEMS on previously exempt units and conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.113 of this title;

(iv) [(iii)] July 31, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap to comply with clause (i) of this subparagraph;

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

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

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

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

(III) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.106(b) of this title; and

<u>(vii)</u> [(vi)] July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap NO_x emission limit to comply with the emission specifications in §117.106(b) of this title.

(B) The requirements of <u>subparagraph (A)(i) of this paragraph</u> [§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) - (iv) (No change.)

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

(1) (No change.)

(2) Emission specifications for attainment demonstration.

(A) (No change.)

(B) The owner or operator shall:

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

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

(I) March 31, 2003, demonstrate that at least <u>50%</u> [47%] of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.108 of this title; and

(II) March 31, 2004, <u>submit the information specified in §117.116 of this title;</u> [demonstrate that at least 95% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.108 of this title; and]

(III) March 31, 2004 [2007], demonstrate compliance with the system cap limit of §117.108 of this title.

(C) For any unit subject to §117.106(c) of this title for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under subparagraph (A)(ii) of this paragraph [paragraph (2)(A)(ii) of this subsection], the owner or operator shall submit to the executive director as soon as practicable, but no later than March 31, 2007, the results of:

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

(D) (No change.)

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

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

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

§117.512. Compliance Schedule for Utility Electric Generation in East and Central Texas.

The owner or operator of each utility electric power boiler or stationary gas turbine 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, and Wharton Counties shall comply with the requirements of Subchapter B, Division 2 of this chapter (relating to Utility Electric Generation in East and Central Texas) as soon as practicable, but no later than the following dates:

(1) May 1, 2003 for units owned by utilities which are subject to the cost-recovery provisions of Texas Utilities Code, §39.263(b):

(A) the owner or operator shall use the period of May 1, 2003 through April 30, 2004 for the initial annual compliance period. Compliance for each subsequent annual period is on a calendar year basis. For example, the second annual compliance period is January 1, 2004 through December 31, 2004; and

(B) the updated final control plan required by §117.145 of this title (relating to Final Control Plan Procedures) shall be submitted by May 31, 2004, and by January 31, 2005; and

(2) May 1, 2005 for all other units: [.]

(A) the owner or operator shall use the period of May 1, 2005 through April 30, 2006 for the initial annual compliance period. Compliance for each subsequent annual period is on a calendar year basis. For example, the second annual compliance period is January 1, 2006 through December 31, 2006; and

(B) the updated final control plan required by §117.145 of this title shall be submitted by May 31, 2006, and by January 31, 2007.

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

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

(1) Reasonably available control technology (RACT). The owner or operator shall for all units, comply with the requirements of Subchapter B, Division 3 of this chapter, except as specified in paragraph (2) of this subsection (relating to lean-burn engines) and paragraph (3) of this subsection (relating to emission specifications for attainment demonstration) [of this subsection], by November 15, 1999 (final compliance date) and submit to the executive director:

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

(D) the first semiannual report required by §117.219(d) or (e) of this title (relating to Notification, Recordkeeping, and Reporting Requirements), covering the period November 15, 1999 through December 31, 1999, no later than January 31, 2000. [; and]

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

(b) (No change.)

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

(1) Reasonably available control technology (RACT). The owner or operator shall, for all units, comply with the requirements of Subchapter B, Division 3 of this chapter, except as specified in

paragraph (2) of this subsection (relating to emission specifications for attainment demonstration), by November 15, 1999 (final compliance date); and [:]

(A) (No change.)

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

(C) (No change.)

(2) Emission specifications for attainment demonstration.

(A) (No change.)

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

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

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

[(I) March 31, 2004, demonstrate compliance with the system cap limit of §117.210 of this title as follows:]

[(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2004, submit a demonstration of the NO_x emission reductions that have been accomplished; and]

[(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2004, were not equipped with flue gas cleanup, shall form the April 1, 2004 - March 31, 2005 system cap limit of §117.210 of this title;]

[(II) March 31, 2005, demonstrate compliance with the system cap limit of §117.210 of this title as follows:]

[(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2005, submit a demonstration of the NO_x emission reductions that have been accomplished; and]

[(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2005, were not equipped with flue gas cleanup, shall form the April 1, 2005 - March 31, 2006 system cap limit of §117.210 of this title;]

[(III) March 31, 2006, demonstrate compliance with the system cap limit of §117.210 of this title as follows:]

[(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2006, submit a demonstration of the NO_x emission reductions that have been accomplished; and]

[(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2006, were not equipped with flue gas cleanup, shall form the April 1, 2006 - March 31, 2007 system cap limit of §117.210 of this title; and]

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

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

[(i) perform stack tests conducted in accordance with §117.211 of this title; or, as applicable,]

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

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

[(I) March 31, 2004, demonstrate compliance with the system cap limit of §117.210 of this title as follows:]

[(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2004, submit a demonstration of the NO_x emission reductions that have been accomplished; and]

[(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2004, were not equipped with flue gas cleanup, shall form the April 1, 2004 - March 31, 2005 system cap limit of §117.210 of this title;]

[(II) March 31, 2005, demonstrate compliance with the system cap limit of §117.210 of this title as follows:]

[(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2005, submit a demonstration of the NO_x emission reductions that have been accomplished; and]

[(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2005, were not equipped with flue gas cleanup, shall form the April 1, 2005 - March 31, 2006 system cap limit of §117.210 of this title;]

[(III) March 31, 2006, demonstrate compliance with the system cap limit of §117.210 of this title as follows:]

[(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of NO_x) is installed on or before March 31, 2006, submit a demonstration of the NO_x emission reductions that have been accomplished; and]

[(-b-) the completed flue gas cleanup NO_x emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2006, were not equipped with flue gas cleanup, shall form the April 1, 2006 - March 31, 2007 system cap limit of §117.210 of this title; and]

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

(C) [(D)] For any units subject to §117.206(c) of this title for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph (2)(A) of this subsection, the owner or operator shall submit to the executive director as soon as practicable, but no later than March 31, 2007, the results of:

(i) stack tests conducted in accordance with §117.211 of this title; or, as applicable,

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

(D) [(E)] The owner or operator shall comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) as soon as practicable, but no later than the appropriate dates specified in that program.

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

(F) The owner or operator shall comply with all other requirements of Subchapter B, Division 3 of this chapter as soon as practicable, but no later than March 31, 2005.

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

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

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

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

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

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

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

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

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

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

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

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

SUBCHAPTER E: ADMINISTRATIVE PROVISIONS
§117.540, §117.560

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

The proposed repeals implement TCAA, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.051(d); and TWC, §5.103.

§117.540. Phased Reasonably Available Control Technology (RACT).

§117.560. Recission.