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ADOPTED RULES

An agency may take final action on a section 30 days after a proposal has been published in the ***Texas Register***. The section becomes effective 20 days after the agency files the correct document with the ***Texas Register***, unless a later date is specified or unless a federal statute or regulation requires implementation of the action on shorter notice.

If an agency adopts the section without any changes to the proposed text, only the preamble of the notice and statement of legal authority will be published. If an agency adopts the section with changes to the proposed text, the proposal will be republished with the changes.

TITLE 25. HEALTH SERVICES

Part VIII. Interagency Council on Early Childhood Intervention

Chapter 621. Early Childhood Intervention Program

Early Childhood Intervention Advisory Committee

- 25 TAC §621.64

The Interagency Council on Early Childhood Intervention (Council) adopts an amendment to §621.64, concerning advisory committee procedure, without changes to proposed text as published in the December 14, 1993, issue of the *Texas Register* (18 TexReg 9258).

The section covers policies and procedures for the ECI Advisory Committee. The amendments clarify reimbursement procedures for ECI Advisory Committee members for child care and attendant care when on official ECI business. There were also minor editorial changes made as a result of the recodification of references to articles previously made under Texas Civil Statutes.

No comments were received regarding adoption of the amendment.

The amendment is adopted under the Human Resource Code, §73.003, which provides the Interagency Council on Early Childhood Intervention with the authority to establish rules regarding services provided for children with developmental delays. The amendments will effect the Health and Safety Code, Chapter 73.

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on June 2, 1994.

TRD-9441727 Tammy Tiner, Ph.D.
Chairperson
Interagency Council on Early Childhood Intervention

Effective date: June 23, 1994

Proposal publication date: December 14, 1993

For further information, please call: (512) 502-4900

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TITLE 30 ENVIRONMENTAL QUALITY

Part I. Texas Natural Resource Conservation Commission

Chapter 117. Control of Air Pollution from Nitrogen Compounds

The Texas Natural Resource Conservation Commission (TNRCC) adopts amendments to §§117.10, 117.103, 117.105, 117.107, 117.109, 117.111, 117.113, 117.115, 117.117, 117.119, 117.121, 117.203, 117.205, 117.207-117.209, 117. 211, 117.213, 117.215, 117.217, 117.219, 117.221, 117.311, 117.313, 117.319, 117.321, 117.411, 117.413, 117.419, 117.421, 117.510, 117.520, 117.530, 117. 540, and 117.560 and the repeal of 117.580, concerning Control of Air Pollution From Nitrogen Compounds. The TNRCC also adopts new §117.223, relating to Source Cap. Sections 117.10, 117.103, 117.105, 117.107, 117.109, 117.111, 117.113, 117.119, 117.203, 117.205, 117.207, 117.209, 117.211, 117. 213, 117.215, 117.219, 117.223, 117.510, 117.520, and 117.540 are adopted with changes to the proposed text as published in the January 4, 1994, issue of the *Texas Register* (19 TexReg 33). Sections 117.115, 117.117, 117.121, 117. 208, 117.217, 117.221, 117.311, 117.313, 117.319, 117.321, 117.411, 117.413, 117.419, 117.421, 117.530, 117.560, and the repeal are adopted without changes and will not be republished.

Revisions to Chapter 117 are adopted in response to a requirement by the United States Environmental Protection Agency (EPA) and the 1990 Federal Clean Air Act (FCAA) Amendments for states to apply reasonably available control technology (RACT) requirements to major sources of nitrogen oxides (NO_x) in the following ozone nonattainment counties: Brazoria, Chambers, Fort Bend, Galveston, Hardin, Harris, Jefferson, Liberty, Montgomery, Orange, and Waller.

Certain general revisions have been made throughout Chapter 117, and are not specifically listed in the discussion of individual section revisions. References to the Texas Air Control Board (TACB) have been changed to the TNRCC to reflect consolidation of the TACB and Texas Water Commission (TWC) on September 1, 1993. Similarly, the word "Board" has been replaced with "Commission." New Title 30, Environmental Quality, was created in the Texas Administrative Code (TAC) effective September 1, 1993, to recodify regulations of the former TACB and TWC. All references to TACB Regulation VII have been changed to 30 TAC Chapter 117 to reflect this change.

The amendments to §117.10, concerning Definitions, add definitions for average activity level for fuel firing, functionally identical replacement, and low annual capacity factor stationary gas turbine or stationary internal combustion engine. The changes also revise the definitions of electric power generating system and low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit for clarity. Other changes revise the definitions of rich-burn and lean-burn engines so that the exhaust stream oxygen concentration at which the engine is capable of being operated, as originally designed by the manufacturer, determines rich- or lean-burn status. (Engines which cannot operate at or below 0.5% oxygen are defined as lean-burns; engines which can operate within these parameters are defined as rich-burn.) The definitions of system-wide emission limit and system-wide emission rate, applicable to utility sources only, are revised to reflect use of maximum rated capacities in calculation of the system-wide emission limit/rate, except for fuel oil firing, where average activity levels are to be used instead. The definition of unit is revised to reflect that a group of units may be replaced by a single new unit, which is thereby limited to the cumulative maximum rated capacity of the units replaced. Subparagraph C of the definition of unit has been deleted

The changes to §117.103, concerning Exemptions, provide for exemption of utility fuel oil firing from the emission limitations of this subchapter under officially declared emergency conditions, and specify verbal and written notification procedures. Exemption criteria for utility gas turbines have been extended to utility gas engines. Minor wording changes have been added for clarity.

The revisions to §117.105, concerning Emission Specifications, specify a carbon monoxide (CO) emission limit of 132 parts per million at 15% oxygen, dry basis, on a block one-hour average for certain utility gas turbines. Other revisions specify that the higher of any permit NO_x limit and the appropriate RACT limit applies to certain units placed into service as functionally identical replacements, and that compliance with this provision does not eliminate the requirement for new units to comply with Chapter 116 (new source review). Minor wording changes have been added for clarity.

Revisions to §117.107, concerning Alternative System-Wide Emission Specifications, specifies procedures for including oil-fired utility units in system-wide averaging plans, for the cases of oil firing only, and for combined gas and oil firing Minor wording changes have been added for clarity Revisions to §117.109, concerning Initial Control Plan Procedures, clarify requirements for listing emission units in the initial control plan, and incorporate minor wording changes for clarity

Amendments to §117 111, concerning Initial Demonstration of Compliance, add references to predictive emissions monitoring systems (PEMS), thereby allowing an alternative to continuous emission monitoring systems (CEMS) already required Other changes allow compliance with the NO_x emission limit for fuel oil firing to be determined based on the first 24 consecutive operating hours a utility unit fires fuel oil, and clarify procedures for determining compliance with NO_x limits on a block one-hour average and with CO limits on a rolling 24-hour average

The revisions to §117 113, concerning Continuous Demonstration of Compliance, extend the provisions for use of PEMS to utility sources. Provisions are given for documenting low annual capacity factor status by use of either totalizing fuel flow meters or elapsed run time meters, as appropriate, as well as procedures to follow when the exemption criteria fail to be met. Minor wording changes have been added for clarity.

Changes to §117.115, concerning Final Control Plan Procedures, require a description of the NO_x control method and testing results to be submitted with the final control plan, and add minor wording changes for clarity. Revisions to §117.117, concerning Revision of Final Control Plan, clarify that new replacement units may be included in the final control plan.

The revisions to §117.119, concerning Notification, Recordkeeping, and Reporting Requirements, add references to PEMS and add minor wording changes for clarity. Revisions to §117.121, concerning Alternative Case Specific Specifications, add minor wording changes for clarity.

The amendments to §117.203, concerning Exemptions, clarify that certain new units placed into service as functionally identical replacement for existing units are not exempt from rule requirements, and specify that emission credits resulting from operation of replacement units is limited to the cumulative maximum rated capacity of the units replaced. Minor wording changes have been added for clarity.

Revisions to §117.205, concerning Emission Specifications, include reorganization of existing subsections for clarity, and reintroduction of procedures for calculating NO_x emission limitations from existing permit limits (previously adopted, but deleted in the most recent proposal). Another amendment clarifies that compliance with the provision allowing the higher of any permit NO_x limit and the appropriate RACT limit, applied to certain units placed into service as functionally identical replacements, does not eliminate the requirement for new units to comply with Chapter 116 (new source review). For wood fuel-fired boilers or process heaters, a new carbon monoxide (CO) emission limitation of 775 ppmv at 7.0% O_2, dry basis has been added which reflects an achievable CO emission rate for these units. Minor wording changes have been added for clarity.

Changes to §117.207, concerning Alternative Plant-Wide Emission Specifications, clarify methods for applying emission limitations for the various categories of regulated equipment. A reference to certain boilers and industrial furnaces (BIF units) was added to the list of equipment classes eligible to participate in plant-wide averaging plans. Minor wording changes have been added for clarity.

Revisions to §117.209, concerning Initial Control Plan Procedures, clarify requirements for listing emission units in the initial control plan. Any major source of NO_x is required to submit an initial control plan, regardless of whether emission specifications apply to any unit within the source. A listing of units required to conduct NO_x testing has been moved from §117.211, concerning Initial Demonstration of Compliance, to §117.209 for better organization and clarity. For units which certify non-operation between June 9, 1993 (effective date of the rule) and April 1, 1994 (due date for initial control plans), a rule revision allows submission of required NO_x emissions testing within 90 days after the unit returns to operation. New listing requirements in the initial control plan pertain to operating modifications, installation and operating information for totalizing fuel flow meters, and documentation of early NO_x reduction projects.

The revisions to §117.211, concerning Initial Demonstration of Compliance, include references to PEMS, references to initial demonstration of compliance tests instead of performance tests, and corrected and updated test methods and test specifications. Conditions for approval of alternate test methods are specified, and other minor changes are added for clarity.

Amendments to §117.213, concerning Continuous Demonstration of Compliance, allow the use of PEMS as an alternative to CEMS. Revisions specify procedures for performing relative accuracy test audits and certain statistical tests. Other revisions specify the conditions for certain exceptions and alternatives to the requirements of 40 Code of Federal Regulations 75, Subpart E. For certain gas turbines using steam or water injection, a revision allows the steam-to-fuel or water-to-fuel ratio monitoring data to constitute the method for demonstrating continuous compliance, with the steam or water injection control algorithms subject to Executive Director approval. Provisions are given for documenting low annual capacity factor status by use of either totalizing fuel flow meters or elapsed run time meters, as appropriate, as well as procedures to follow when the exemption criteria fail to be met. Minor wording changes have been added for clarity.

Revisions to §117.215, concerning Final Control Plan Procedures, require a description of the NO_x control method and testing results to be submitted with the final control plan, specify methods for assigning NO_x emission limits to the various categories of regulated equipment, and add minor wording changes for clarity. Revisions to §117.217, concerning Revision of Final Control Plan, clarify that new replacement units may be included in the final control plan.

The revisions to §117.219, concerning Notification, Recordkeeping, and Reporting Requirements, add references to PEMS, specify procedures for determining periods of excess emissions for gas turbines using steam or water injection, and add minor wording changes for clarity. Revisions to §117.221, concerning Alternative Case Specific Specifications, add minor wording changes for clarity.

New §117.223, concerning Source Cap, incorporates the requirements of §117.580, which is being repealed concurrently with this adoption. One revision to §117.223 addresses EPA concerns about RACT equivalency by changing the method of calculating the historical activity level by specifying the use of actual daily heat input, based on a two-year average heat input plus one standard deviation. Alternate methods are allowed, with Executive Director approval, for determining the daily heat input when sufficient historical data are not available. Other changes include the deletion of language duplicated in §117.113 and §117.213, and requirement that the method of calculating the actual heat input for each unit included in the source cap must be included in the initial control plan. Nomenclature used in formulas has been revised for consistency with §117.570, concerning Trading, which is currently pending adoption.

Revisions to §§117.311, 117.313, 117.319, and 117.321 (concerning Adipic Acid Manufacturing) and §§117.411, 117.413, 17.419, and 117.421 (concerning Nitric Acid Manufacturing) add references to PEMS in addition to CEMS, and add minor wording changes for clarity.

Amendments to §117.510, concerning Compliance Schedule for Utility Generation, specify compliance schedules for certain utility units which depend on whether the units are required to install CEMS pursuant to 40 CFR 75. Other revisions specify a May 31, 1995 compliance date for submitting initial demonstration of compliance testing and CEMS or PEMS test results, for utility units not required to install CEMS or PEMS, and for units operating with CEMS or PEMS which comply on a block one-hour average. Units operating with CEMS or PEMS and complying on a rolling 30-day average are allowed to submit such results by July 31, 1995. In addition, initial demonstration of compliance testing for fuel oil firing is allowed to be submitted within 60 days after completion of such testing.

Revisions to §117.520, concerning Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources, require major NO_x sources which have units subject to emission specifications to submit an initial control plan by April 1, 1994. Major NO_x sources which have no units subject to emission specifications must submit an initial control plan by September 1, 1994. In addition, information required by certain provisions of §117.209 which are being added or amended with this adoption must be submitted by September 1, 1994. Other revisions require units operating with CEMS or PEMS which comply on a block one-hour average to submit applicable tests by May 31, 1995, and for those units operating with CEMS or PEMS and complying on a rolling 30-day average, to submit such results by July 31, 1995

Revisions to §117.530, concerning Compliance Schedule for Nitric Acid and Adipic Acid Manufacturing Sources, include references to PEMS in addition to CEMS, and add minor wording changes for clarity

In order to provide more flexibility for sources requesting additional time to implement NO_x RACT through the phased RACT petition process, new subsection (c) is added to §117.540, concerning Phased RACT, which allows a source to use mobile emission reduction credits (MERCs) from scrapped motor vehicles to offset NO_x emissions on an interim basis until compliance is achieved, up to a maximum period of 36 months. This revision was not part of the January 1994 rule proposal, but was added later to cross-reference separate rulemaking in §114.29 (Accelerated Vehicle Retirement Program), proposal pending, and §117 570 (Trading), adoption pending. Since §114.29 will specify the actual mechanism and procedures for MERC trading when adopted, the TNRCC believes that referencing this option in §117.540 with this adoption is timely and appropriate, since it increases rule flexibility while providing a potential net environmental benefit. The option to use MERCs may be useful for sources whose phased RACT petitions do not meet the rule criteria for approval.

The following commenters supported the Texas Chemical Council (TCC) and/or the Texas Mid-Continent Oil & Gas Association (TMOGA) comments: Amoco Chemical Company, Texas City (Amoco Chem Texas City), Amoco Chemical Company, Chocolate Bayou Plant (Amoco Chem Chocolate Bayou), Chevron, Dow Chemical, DuPont Gulf Coast Regional Manufacturing Services (DuPont), Exxon Chemical Americas, Exxon Company U.S.A. (Exxon), Fina Oil and Chemical Company (Fina), and Mobil Oil Corporation. In all instances where they agree, they will be referred to as TCC/TMOGA, et al., TCC et al., or TMOGA, et al. In instances where they differ or comment on other issues, the individual commenters will be specifically identified.

General Comments.

In order to provide more flexibility for sources requesting additional time to implement NO_x RACT through the phased RACT petition process, new subsection (c) was added to §117.540 (Phased RACT) providing the option for a source to use mobile emission reduction credits (MERCs) from scrapped motor vehicles to offset NO_x emissions on an interim basis until compliance is achieved, up to a maximum period of 36 months. This revision was not part of the January 1994 rule proposal, but was added later to cross-reference separate rulemaking in §114.29 (Accelerated Vehicle Retirement Program), proposal pending, and §117.570 (Trading), adoption pending. Since §114 29 will specify the actual mechanism and procedures for MERC trading when adopted, the staff believes that referencing this option in §117.540(c) with this adoption is timely and appropriate. The staff believes that the new provision in §117.540 increases rule flexibility while providing a potential net environmental benefit. The option to use MERCs may be useful for sources whose phased RACT petitions do not meet rule criteria for approval

TCC/TMOGA et al. expressed support for the innovative nature of many of the proposed amendments, and for the manner in which the Texas Natural Resource Conservation Commission (TNRCC) has involved members of the regulated community in developing the nitrogen oxides (NO_x) reasonably available control technology (RACT) regulation, 30 TAC 117.

The staff acknowledges the support from the commenters.

The Galveston-Houston Association for Smog Prevention (GHASP) commented that the use of different terminology to express averaging periods is confusing and needs clarification For example, various rule sections use the terms "rolling monthly average," "rolling 30-day average," and "30-day averaging period."

The staff acknowledges that there were inconsistencies in terminology in the proposed rule ("rolling monthly average" and "30-day averaging period") The staff has specified averaging periods that take into account the data that are being reported and has used averaging periods that are in common usage in the air pollution control field For low annual capacity boilers and heaters, the exemption period is based on one year's worth of heat input. The staff decided that the heat input data for a moving (or rolling) 12-month period is more appropriate for this case. The rolling 12-month year makes up-to-date enforcement determinations practical. The results of the last complete month are included in the average, so compliance status is not indeterminate for a long period of time. A rolling 30-day average means that the emission limits are applied to a 30 consecutive day period, consisting of a given day plus the previous 29 days. Likewise, a rolling 24-hour average means that the emission limits are applied to a 24 consecutive hour period, consisting of a given hour plus the previous 23 hours The staff appreciates the commenter's response in pointing out the language inconsistencies, and has revised the references to "rolling monthly average" to "rolling 12-month average" and "30-day averaging period" to "rolling 30-day averaging period."

Texaco Chemical Company (Texaco) suggested that a typographical error, a parenthesis after "O_2" in the second sentence of proposed §117. 213(b), be corrected. TCC/TMOGA et al. and Texaco noted a typographical error in proposed §117.213(k) pertaining to the term "hour-per-year."

The staff acknowledges these two typographical errors inadvertently added by the *Texas Register*, and has deleted the parenthesis after "O_2" in §117.213(b) and the term preceding "hour-per-year" in §117.213(k).

GHASP objected to the proposals in §117.105(n)(2), §117.203(b)(1), and §117.205(a)(2) allowing the higher of a permit limit or a RACT limit to apply to certain units. GHASP further commented that controls should be required for all grandfathered units in order to achieve maximum NO_x reductions.

The provision to allow certain units placed into service between June 9, 1993, and May 31, 1995, to use the higher of best available control technology (BACT) or RACT limitations creates an incentive to replace old units with new, cleaner, more efficient ones by allowing the resulting emission reductions to generate reduction credits for other NO_x RACT sources. The current version of the rule already requires certain existing sources to apply RACT controls, and the United States Environmental Protection Agency Region 6 Office (EPA) has previously commented that additional rules for certain currently exempted sources will be necessary

GHASP commented that controls should be required for all grandfathered units in order to achieve maximum NO_x reductions

The staff agrees that substantial NO_x reductions will likely be required in order to attain the ozone standard in the Houston/Galveston and the Beaumont/Port Arthur ozone nonattainment areas However, there are practical technical and economic considerations in the implementation of a rule of this scope which point to phasing in progressively more restrictive standards over time. Regulation VII (30 TAC 117) as adopted on May 11, 1993, represents a significant step toward attaining the ozone standard. The staff estimates that the rules will result in NO_x reductions on the order of 10% to 15% from major stationary sources. As information becomes available from the emissions testing results required as part of the initial control plans due April 1, 1994, and the evaluation of Urban Airshed Modeling results, the staff will be able to determine further needed NO_x reductions and initiate the next round of rulemaking.

TCC/TMOGA et al. and Texaco recommended that in proposed §117.215(b)(4), relating to Final Control Plan Procedures, the reference should be "paragraphs (1)-(3)."

The staff agrees with the commenters and has changed the reference in §117.215(b)(4) as suggested to "paragraphs (1)-(3)."

GHASP objected to the use of predictive emissions monitoring systems (PEMS) as an alternative to continuous emissions monitoring systems (CEMS) throughout the proposed rules, stating concerns about equivalence to CEMS and enforceability.

The rule, in reflecting the staff's directive to implement NO_x RACT cost-effectively, provides for the use of PEMS as an alternative to CEMS. The staff has used guidelines for accepting alternatives to CEMS which the EPA has issued in 40 Code of Federal Regulations (CFR) 75, Subpart E. The rules are designed to ensure that PEMS provide data with the same precision, reliability, and timeliness as provided by CEMS. Data collection and recordkeeping for PEMS is done continuously by computer, as it is for CEMS, and is sufficient for enforcement purposes.

EPA commented that the undesignated head "Nitric Acid Manufacturing–General" in Subchapter C regarding Acid Manufacturing and Subchapter E regarding Gas-Fired Steam Generation were not referred to in the current proposal, and assumed that these portions of the rule remain unchanged

The staff did not propose any changes to Subchapter E or the undesignated head "Nitric Acid Manufacturing-General" in Subchapter C. These portions of the rule remain as they were adopted on May 11, 1993.

GHASP objected to the use of system-wide emissions averaging, stating that it does not maximize emissions reductions and is difficult to enforce. The commenter emphasized the need for obtaining maximum reductions early in the control strategy process

The staff supports the concept of system-wide averaging and has designed a cost-effective means of complying with the rule which assures that RACT-equivalent NO_x reductions are obtained Enforcement is achieved by utilizing data (maintained by computers) which will demonstrate compliance.

GHASP commented that recordkeeping requirements of only two years were inadequate in proposed §§117.119, 117.219, 117 319, and 117 419, relating to Notification, Recordkeeping, and Reporting Requirements, and recommended that records be kept for at least five years.

The staff has maintained consistency with federal New Source Performance Standards (NSPS) Subpart A General Provisions, which require retaining two years of data. The adopted rule extends the NSPS recordkeeping requirements to existing sources. By following NSPS, the staff believes that burdensome recordkeeping requirements have been minimized.

GHASP commented on the inadequacy of only verbal notification before conducting emissions testing or CEMS or PEMS performance evaluation under proposed §117.119(b)(1) and (2), and elsewhere throughout the regulation. GHASP recommended requiring prior written notification as well to ensure proper documentation for enforcement purposes.

Verbal notice of testing allows the TNRCC the opportunity to witness emissions testing. The written documentation required after the completion of emissions testing serves the agency's enforcement purposes by creating a retrievable file record Currently, the Beaumont and Houston regional offices use verbal notification as the initial contact by a company to report upset conditions; written notification follows after the initial phone call. This policy is retained for consistency in Chapter 117.

An individual representing GHASP commented that he made a telephone request to the TNRCC Austin office for a copy of the proposed regulation, but never received it. The commenter requested an explanation, since this has occurred on more than one occasion.

The staff apologizes for the error. The TNRCC makes available copies of proposed and adopted rules by various methods to the public. The agency has a new, free computer bulletin board service (BBS) which will contain text files of all the air, water, and waste rules, as well as other numerous documents to assist the public. The telephone number for the TNRCC ONLINE BBS is (512) 239-0700. The regional offices also have available adopted and proposed rules which can be copied for public distribution. Proposals are also published in the *Texas Register*. In addition, copies of air regulations can be obtained by calling staff of the Air Quality Planning Division, Regulation Development Section at (512) 239-1970 or 239-1966.

Comments received for §117 10 Definitions.

TCC/TMOGA et al. requested that the definition of "electric power generating system" be revised to clarify that the phrase "owned or operated by" in the definition refers to the listed emission units, not to the electric power generating system which they comprise

The staff agrees with the commenters and has added the phrase "which are" before the phrase "owned or operated by" in the definition of "electric power generating system."

Texas Eastern Transmission Corporation (Texas Eastern) expressed support for the proposed revision to definitions of "lean-burn engine" and "rich-burn engine."

The new definitions are meant to clarify rule applicability rather than to change an underlying requirement. The intent was to require emission reductions on those engines which are relatively cost-effective to control. Conventional three-way catalytic converters are cost-effective. However, these converters only work on engines with less than 0.5% oxygen in the exhaust stream. The old definition, based on 4.0% oxygen in the uncontrolled exhaust stream, was concerned with circumvention of control requirements. The 4.0% level was selected as a level that a rich-burn engine cannot exceed in practice. The proposed definition, based on 0.5% oxygen, reflects whether an engine is capable of being controlled effectively. By basing the definition on original equipment manufacturer capability, issues of circumvention through manipulation of operated oxygen level are avoided.

TCC/TMOGA et al. commented on the proposed definitions of "low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit" and "low annual capacity factor stationary gas turbine or stationary internal combustion engine." They stated that the use of a rolling monthly average in determining the maximum annual heat input and maximum annual hours of operation significantly lowers the cutoff level for qualifying for the low annual capacity factor exemption. They suggested that the phrase "based on a rolling monthly average" be deleted, and that the definition clarify that exemptions are based on data collected for a calendar year. Monsanto recommended the wording "...based on a rolling accumulative heat input over the most recent 12 complete months" to reflect the rule's intent that the rolling average consists of the current 12 months' worth of heat input data.

The rolling average is not meant to lower the cutoff point for qualifying for the low annual capacity factor exemption. The heat input or operating hours of a unit is meant to be cumulative during the 12-month window. At the end of each successive month, the new month's data is added and the oldest month's data is subtracted to create the new average. The time period from June 1, 1995-May 31, 1996, will constitute the first 12 months of data in verifying the low annual capacity factor status of a unit. The staff agrees with Monsanto's recommendation to clarify the averaging period for low annual capacity units, and has revised the phrase to read "based on a rolling 12-month average."

EPA commented on the definitions of "system-wide emission limit" and "system-wide emission rate," stating that the term "average activity level" is defined for fuel oil firing but not for other fuels. EPA recommended that these terms be clarified. EPA further commented that the option for sources to use either maximum rated capacity (MRC) or actual heat input in determining a system-wide emission limit or rate might not produce NO_x reductions equivalent to traditional RACT. EPA recommended that the TNRCC either demonstrate RACT equivalency with the proposed approach, or specify whether actual or maximum heat input may be used in system-wide averaging plans.

The definitions of "system-wide emission limit" and "system-wide emission rate" have been revised to eliminate the option of using average activity levels for gaseous and solid fuel firing for the purpose of calculating system-wide emission limits and system-wide emission rates.

Most utility boilers in Texas are designed to burn natural gas. Some were modified to allow for oil firing during emergency conditions and/or periods of natural gas supply limitation. System-wide emission limits and system-wide emission rates are best calculated using average activity levels, accounting for variations in historical capacity factors of individual units as part of the determination process. The staff believes it is unlikely that unit-specific emission limitations would be preferentially assigned based on the historical activity level of each unit. In fact, if historical activity levels are to be considered in the compliance planning process, it is likely that the most NO_x controls would be installed on units with the highest historical activity levels (highest capacity factors). The staff believes that determinations of system-wide emission rates and system-wide emission limits based on maximum rated capacity for units burning a primary fuel are essentially equivalent to determinations based on average activity levels. In the State Implementation Plan (SIP) narrative to be submitted by November 15, 1994, EPA will be provided with a RACT equivalency demonstration audit of both scenarios. For utility boilers burning fuel oil, the possibility of prorating unit-specific emission limitations based on average activity levels is more probable. To ensure RACT equivalency, the use of average activity levels will be the only option allowed in determining system-wide emission limits and system-wide emission rates for units burning fuel oil.

TCC/TMOGA et al. and Texaco commented that subparagraph (B) of the proposed definition of "unit" and proposed §117.205(a)(2), relating to Emission Specifications, should be modified to reflect that a unit could replace more than one existing unit, in which case the new replacement unit should be limited to the cumulative capacity limit of the units replaced.

The staff agrees that a unit may replace more than one existing unit, and has modified language at §117.10 ("unit" definition, subparagraph (B)), §117.105(n)(2), and §117.205(a)(2) to reflect this concept. In addition, references to limitations of "capacity limit" of the unit replaced have been changed to "cumulative maximum rated capacity" in the cited rule sections and in §117 203(b)(1), relating to Exemptions, in order to accurately convey the staff's intent

GHASP commented that the term "functionally identical replacement" in proposed §§117.105(n)(2), 117.203(b)(1), and 117 205(a)(2) needs to be defined

A new definition for the term "functionally identical replacement" has been added to §117.10, as follows. "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"

TCC/TMOGA et al. and Texaco recommended that in subparagraph (C) of the proposed definition of "unit," the definition be modified to include units placed into service before the dates specified in proposed §117.520 (relating to Compliance Schedules for Commercial, Institutional, and Industrial Combustion Sources) with the intent of complying with §117.223 (relating to Source Cap). The commenters stated that the definition as proposed would imply that NO_x RACT applies to any new source placed into service after June 9, 1993, when in fact more stringent BACT would apply.

After reconsidering this issue, the staff has deleted proposed subparagraph (C) from the definition of "unit," which would have required units placed into service after June 9, 1993, belonging to an equipment category which is complying with the source cap, to be included in the cap. Emission units placed into service after June 9, 1993 (effective date of the rule) are thus not required to participate in the source cap, since, as stated by the commenters, such units would be subject to new source review requirements (NSR) more stringent than RACT. Besides, establishing historical heat input rates for new units which have not previously operated poses problems which §117. 223 was not designed to address. Given the rigorous nature of NSR and the resultant environmental benefit, the staff believes that this approach is sound.

GHASP commented on the need for a uniform definition of the term "unit" without exemptions or exceptions.

Revisions to the definition of "unit" were proposed in order to address cases where equipment is placed in service after June 9, 1993, either as a replacement for existing equipment (subparagraph (B) of the definition) or as a part of an equipment category participating in a source cap (subparagraph (C)) By qualifying replacement equipment under certain conditions as a "unit," subparagraph (B) extends rule requirements to such equipment As discussed in the previous response, subparagraph (C) has been deleted The intent of these revisions is to clarify rule applicability to certain new sources, not to provide exemptions or exceptions to such sources

Comments received for §117 103 Exemptions

EPA commented that proposed §117 103(c), which provides for emergency exemption from emission limitations for fuel oil firing, should specify a maximum limit for oil firing, in hours per year, which if exceeded would subject the unit to rule emission limitations

The staff does not agree that the rule should specify a maximum time limit for fuel oil firing during emergency conditions Since durations of emergency operating conditions are unpredictable, the staff believes that the maximum duration of these conditions need not be specified as long as they meet the criteria established by the rule

Houston Lighting and Power (HL&P) expressed support for proposed §117 103(c), citing the cost savings of avoiding the selection of emission controls based on firing of fuel oil, which is historically an infrequent, emergency situation

The staff acknowledges the support from the commenter.

GHASP commented that the TNRCC should verify the existence of emergencies requiring fuel oil firing.

Since §117.103(c) already requires that all emergency operating conditions be approved by the Executive Director, the staff believes that the commenter's concerns are adequately addressed.

EPA recommended that in the third sentence of proposed §117.103(c), language be added to specify that the Executive Director must be notified no later than 48 hours after declaration of emergency conditions. EPA further commented that the source should be required to submit written notification detailing the same information required in the verbal notification, no later than five calendar days after declaration of the emergency This additional written notification would supplement, not replace, the summary notification to be submitted within two weeks after termination of emergency fuel oil firing HL&P recommended deletion of the requirement to provide detailed verbal notification, stating that is unreasonable to expect advance predictions of all the variables requested under the proposed rule GHASP commented that written notification should be submitted within three days after the termination of emergency fuel oil firing

The staff has revised the verbal notification requirements of §117 103(c) by adding the phrase "but no later than 48 hours after declaration of the emergency" at the end of the third sentence In addition, the staff agrees with EPA that verbal notification must be followed up with a written notification within five days after the declaration of emergency conditions, and has made the recommended change

The staff disagrees with HL&P that the requirement to provide verbal notification should be deleted on the basis that advance predictions of all variables are not possible The rule requires that verbal notification shall identify anticipated emergency variables Utilities will not be held liable for the accuracy of the information provided in their verbal notifications as long as the information is the best they can provide at the time the verbal notification was made

The staff disagrees with GHASP that the written notification must be submitted within three days after termination of emergency conditions The purpose of written notification is to identify the dates and times that oil firing began and ended, the duration of the emergency period, the affected oil firing equipment, and the quantity of oil fired in each boiler The staff believes that three days does not provide sufficient time to generate a detailed report that includes this information A two-week period will allow utilities more time to produce a more accurate and accountable report

Comments received for §117 105 Emission Specifications

HL&P recommended that proposed §117 105(n) be deleted, noting that its requirements appear to be redundant with §117 105(e), pertaining to auxiliary boilers Since the permitted NO_x limitations for three of its auxiliary boilers are already at or below the 0 12 pound per million British thermal units (lb/MMBtu) limitations specified in §117 105(n), this provision appears to be unnecessary HL&P also commented that the reference to heaters is inappropriate since these units are not regulated under the utility rule

Section 117 105(n), and its parallel for industrial units at §117 205(a) (1)(A), allows gas-fired boilers and heaters permitted after March 3, 1982, with an emission limitation of 0 12 lb NO_x/MMBtu to retain that limitation for purposes of rule compliance This provision was primarily intended for certain industrial boilers and heaters which had received permits to install "first generation" low NO_x burners, and for which additional RACT controls to achieve only a slightly greater NO_x reduction would not be cost-effective The rule provision was extended to utility units at §117 105(n), with the assumption that some of the affected units could benefit from the rule Although there is some overlap with the provisions of §117.105(e), §117 105(n) has been retained to maintain the requirement, in accordance with EPA guidance, that the lower of RACT or BACT emission limitations apply.

The reference to heaters in §117.105(n)(1) was inadvertently carried over from the corresponding industrial rule at §117.205(a)(1)(A). Since heaters are not regulated under the utility rule, this reference has been deleted.

In addition, language has been added to §117 105(n)(2) clarifying that the intent was not to limit the annual activity level of replacement units, but rather to restrict emission credits in averaging plans to the cumulative MRC of the units replaced, and that compliance with §117.105(n)(2) does not eliminate the requirement for new units to undergo NSR under Chapter 116

Comments received for §117 107 Alternative System-Wide Emission Specifications

EPA commented that proposed §117 107(a) specifies use of the MRC when calculating the system-wide emission limit and system-wide emission rate This requirement appears to be inconsistent with the optional use of either MRC or average activity levels given in the definitions of "system-wide emission limit" and "system-wide emission rate" in §117 10 EPA also recommended that other subsections in the undesignated head pertaining to utility electric generation be re-evaluated in light of these comments

The definitions of "system-wide emission limit" and "system-wide emission rate" were revised to eliminate the option of using average activity level for gaseous and solid fuel firing This revision will ensure consistency with the proposed rule language of §117 107

HL&P expressed support for proposed §117 107(b), which allows system-wide averaging for fuel oil firing in utility boilers capable of firing natural gas and fuel oil. HL&P stated that this amendment gives utilities more flexibility in implementing cost-effective NO_x control measures

The staff acknowledges the support from the commenter

Comments received for §117 109 Initial Control Plan Procedures

GHASP recommended revising the wording in the second sentence of proposed §117 109(a) to additionally require compliance with all TNRCC rules and regulations as a condition of approval of the initial control plan

The purpose of the initial control plan is to document information about certain NO_x emission units at a source, in order that the staff can more accurately assess emissions from these units and determine whether any projected control methods and schedules appear adequate and reasonable. Information contained in the initial control plan is not enforceable, since it only represents a source's preliminary strategy for achieving compliance with the rule emission limits. The plan may be revised at any time before the final control plan is due on May 31, 1995, and the final control plan may subsequently be revised with approval of the Executive Director Therefore, imposing the additional requirement of compliance with all TNRCC rules and regulations as a condition of approval of the initial control plan would appear to be inconsistent with the purpose of the plan.

Gulf States Utilities Company (Gulf States) commented on the proposed requirement in §117.109(b)(8) that units required to install totalizing fuel flow meters must state in the initial control plan whether these devices have been placed in operation by April 1, 1994 The commenter recommended that the TNRCC clarify that totalizing fuel flow meters are required to be installed by May 31, 1995, rather than April 1, 1994

The commenter is correct in stating that totalizing fuel flow meters are not required to be installed until May 31, 1995 The proposed requirement for listing installed meters in the initial control plan, due April 1, 1994, should not be construed as a requirement to have the meters installed by then

Comments received for §117 111 Initial Demonstration of Compliance

HL&P recommended that proposed §117 111(d) be revised to include language specific to gas turbines The current language applies only to rolling 30-day and 24-hour averages applicable to boilers, and should address the one-hour block averaging times required for gas turbines

New §117.111(d)(3) has been added to address the one-hour block averaging times applicable to gas turbines Existing paragraph (3) has been renumbered as (4)

Comments received for §117 113 Continuous Demonstration of Compliance

EPA recommended that the phrase "and operating" be added in the second sentence of proposed §117.113(a), after "The CEMS shall be installed. ."

The recommended wording has been added in order to clarify the rule's intent that CEMS should be operating by the final compliance date of May 31, 1995

HL&P commented that language in proposed §117.113(a)(4) should reflect that CEMS are not equipped to measure fuel flow, but are able to accept measured data from other instruments which are capable of that function.

The staff agrees with the commenter and has made the recommended change. The last sentence of §117 113(a) was revised to read, "Each CEMS shall be able to monitor measured exhaust or fuel flow rate data obtained by a certified flow meter and have the capability of measuring the following.". Existing §117.113(a)(4) was deleted since it pertains to CEMS measurement of fuel flow.

HL&P expressed general support for proposed §117 113(e), which would allow the use of PEMS as an alternative to CEMS, citing the high accuracy and cost-effectiveness afforded by PEMS.

The staff acknowledges the support from the commenter.

GHASP objected to the option allowed by proposed §117 113(e) for sources not subject to 40 CFR Part 75 (federal acid rain rules) to use PEMS as an alternative to CEMS GHASP commented that the proposed use of PEMS should be subject to public input through a hearing or meeting

The proposed rule language of §117.113(e) may have led the commenter to conclude that the option of using PEMS as an alternative to CEMS is limited to sources that are not subject to 40 CFR 75 The 40 CFR 75 rules allow for the use of PEMS as an alternative to CEMS. The certification and performance testing requirements, however, are somewhat different from those proposed in this regulation. Sources which are subject to 40 CFR 75 are required to use the PEMS certification procedure of 40 CFR 75, Subpart E, while sources which are not subject to 40 CFR 75 are required to use the PEMS certification procedure of §117 213(c) With regard to receiving public input on the use of PEMS, the TNRCC has followed its customary rulemaking process of conducting public hearings, taking oral and written testimony, and evaluating public comments before final rule adoption

HL&P recommended that §117 113(e) be amended to allow the use of PEMS on sources affected by 40 CFR 75 The commenter stated that the provision as proposed would defeat the purpose of developing cost-effective and innovative technologies such as PEMS, and could result in having to continually purchase CEMS to replace aging monitors

The commenter may have interpreted proposed §117 113(e) to mean that sources subject to 40 CFR 75 do not have the option of using PEMS as an alternative to CEMS Sources subject to 40 CFR 75 do have this option, but they must demonstrate equivalency of PEMS to CEMS using the certification procedure of 40 CFR 75, Subpart E in its entirety, rather than using the somewhat different certification procedure of §117 213(c) The staff has revised §117 113(e) by adding a statement which clearly identifies the option of using PEMS for sources subject to 40 CFR 75

EPA recommended that proposed §117 113(e) be revised to clarify that any alternative methods to CEMS or PEMS also need to be approved by EPA

Section 117.113(e) has been revised to require EPA approval for alternative monitoring methods other than PEMS and CEMS

EPA commented that when its final Enhanced Monitoring rules are issued, the TNRCC will need to evaluate the rule's PEMS provisions to ensure consistency with the federal rules

The staff is aware of the proposed enhanced monitoring rules, and is currently participating in an agency-wide implementation team to develop enhanced monitoring protocols for stationary sources This approach should ensure that PEMS provisions in the rule are consistent with EPA's final enhanced monitoring rules

HL&P commented that the reference to "subsection (e)" in proposed §117 113(a) should be changed to "subsection (f)" to reflect renumbering of the proposed rule

The referenced rule citation has been changed to reflect the renumbering in this section.

EPA commented that proposed §117.113(i) should clarify whether a source that has exceeded its exemption limit would still be subject to enforcement action if it has submitted an acceptable compliance plan within the required 90-day time frame.

A company could be subject to enforcement action by the TNRCC based on exceeding its exemption limit, even if the company had submitted an acceptable compliance plan by the required date A claimed exemption for low annual capacity should be based on either current operating data which demonstrates low annual capacity, or else the company should account in its initial control plan the steps taken to decrease the unit's operating capacity to allow the unit to meet the exemption level If the agency determines that the exemption was claimed without intent to operate the unit at or below the required low annual capacity level, then the TNRCC may enter into an enforcement action under §101 3, relating to Circumvention

Comments received for §117 115 Final Control Plan Procedures

HL&P commented on the need for consistent deadlines for submittal of initial demonstration of compliance test results The commenter noted inconsistencies between §117 115(b)(4), which requires submittal of the final control plan by May 31, 1995, and §117 115(b)(3), which requires submittal by July 31, 1995 HL&P recommended that §117 115(b)(4) either be deleted or amended to reflect a consistent deadline of July 31, 1995

The July 31, 1995, date for submittal of initial demonstration of compliance test results applies only to those units complying with a lb/MMBtu emission limit on a rolling 30-day average For such units having NO_x controls installed as late as May 31, 1995, this extended schedule gives time to conduct testing over a 30-day period and submit the results Submittal of compliance test results is required by May 31, 1995, for all other units New §117 510(4), (5), and (6) have been added which clarify compliance schedules for units without CEMS or PEMS requirements, units operating with CEMS or PEMS and complying on a 30-day rolling average, and units operating with CEMS or PEMS and complying on a block one-hour average Proposed §117 510(5) and (6) have been renumbered as §117 510(7) and (8), respectively.

Comments received for §117.119 Notification, Recordkeeping, and Reporting Requirements.

HL&P commented that written notification of the compliance test within 15 days after completion, as proposed in §117 119(b)(1), is unnecessary, and recommended that this requirement be eliminated

The written documentation required after the completion of emissions testing is needed for agency enforcement purposes. If the final control plan is submitted within 15 days after testing, the notification in the final control plan satisfies the requirement of §117 119(b)(1).

HL&P commented that the requirement in proposed §117.119(b)(2) for submitting results of compliance testing within 60 days after completion is redundant, noting that §117.115(b)(3) already requires submittal of these results as part of the initial control plan. The commenter recommended that this requirement be eliminated.

The requirement to submit results of initial demonstration of compliance testing or CEMS or PEMS performance evaluation within 60 days is actually contained in §117.119(c). Also, it should be noted that §117.115(b)(3) refers to the final, not the initial, control plan. The intent of the rule is that these data be submitted within 60 days after completion of testing or evaluation, but no later than July 31, 1995. Therefore, the requirement in §117.119(c) has been retained.

HL&P commented that in proposed §117.119(e)(5)(B), the reference to "results of initial demonstration of compliance" should be replaced by "results of initial certification testing."

The purpose of recordkeeping requirements is to have relevant data accessible to regulatory agencies for at least two years after such data have been collected. The reference to "results of initial demonstration of compliance" has been replaced by "results of initial certification testing" in proposed §117 119(e)(5), since this paragraph pertains specifically to the operation and quality assurance of CEMS, PEMS, and steam- or water-to-fuel ratio monitoring. However, the need for maintaining performance test results, including initial demonstration of compliance, is valid. Therefore, this requirement has been moved from §117.119(e)(5) to new §117.119(e)(6).

Comments received for §117.121 Alternative Case Specific Specifications.

EPA commented that in proposed §117.121, a source's ability to use system-wide averaging at MRC under §117.107 may be weighed in considering whether the approval of alternative emission specifications is justified. EPA stated that this appeared inconsistent with the proposed definitions of "system-wide emission limit" and "system-wide emission rate" in §117.10, which allow use of either MRC or average activity levels in calculating the system-wide emission rate and limit.

The staff has revised §117.121 to read, "..meet emission specifications through system-wide averaging computed in accordance with §117.107." The recommended changes have been made to the definitions of "system-wide emission limit" and "system-wide emission rate" will ensure consistency with the proposed rule language of §117.107.

Comments received for §117.203 Exemptions.

EPA commented that the SIP submittal to EPA must provide a detailed analysis showing that any exemptions of major sources from NO_x RACT control requirements in proposed §117.203 and §117.205(g) are based on the TNRCC's finding that such controls are not technically or economically feasible. EPA specifically commented on the need for justifying exemptions for chemical processing gas turbines and stationary gas turbines and internal combustion engines used in agricultural operations.

The TNRCC intends to submit documentation of rulemaking activities for certain sources currently exempt from NO_x RACT requirements in a future SIP submittal. This analysis would include the specific types of units identified by EPA.

TCC, Amoco Chem Texas City, Amoco Chem Chocolate Bayou, and Exxon Chem suggested language in proposed §117.203(b)(1) to emphasize that only replacement units not subject to Chapter 116 BACT review under a new source review permit or permit amendment, i.e., those installed under a Standard Permit, are subject to NO_x RACT rule requirements, including restrictions limiting operating capacity to that of the units replaced. Both Amoco companies commented that increases in production capacity without related emission increases could help offset the costs of modification, and should be allowed.

The staff disagrees with the commenters regarding the scope of standard permits granted pursuant to §117.550 (relating to Standard Construction Permits for NO_x RACT Projects). Standard permits do not authorize the construction of new production equipment, including replacement units, without undergoing new source review (NSR) and applying appropriate BACT or lowest achievable emission rate (LAER) controls. The use of standard permits is limited to NO_x abatement equipment or NO_x control techniques which are applied to existing emission units in order to comply with the NO_x RACT rule requirements.

With regard to limitations of operating capacity for replacement units, the intent of the rule was to restrict emission credits in averaging plans to the cumulative maximum rated capacity (MRC) of the units replaced, not to limit the annual activity level of the replacement units. Rule language in §117. 203(b)(1) has been revised to clarify this point.

TCC/TMOGA et al. recommended deletion of the phrase "based on a rolling monthly average" in proposed §117.203(b)(6)(B) to clarify that exemptions are based on data collected for a calendar year.

The staff has revised the phrase to read "based on a rolling 12-month average."

Comments received for §117.205 Emission Specifications.

TCC/TMOGA et al. commented that existing §117.205(a)(2)(A) and (B) were deleted in the proposed version, thus eliminating important features in the rule concerning calculation procedures for NO_x emission rates from existing permitted units. They recommended reinstating the deleted provisions as renumbered §117.205(a)(2).

The staff agrees with the commenters, and has reinstated the deleted subparagraphs according to the commenters' suggestion by renumbering the proposed §117.205(a)(2) to §117.205(a)(3) and adding two subparagraphs as §117.205(a)(2)(A) and (B) which will reinstate the original subparagraphs.

TCC/TMOGA et al. suggested adding language in proposed §117.205(a)(2) clarifying that restrictions which limit operating capacity to that of the replaced units do not apply to replacement units subject to BACT review under a new source review permit or permit amendment. They also recommended that proposed §117.205(a)(2) be modified to reflect that a unit could replace more than one existing unit, and to clarify that the optional inclusion of replacement units refers to the plant-wide average and source cap compliance options

The intent of the referenced paragraph was not to limit the annual activity level of replacement units, but rather to restrict emission credits in averaging plans to the cumulative MRC of the units replaced Language has been added to the referenced rule paragraph, now renumbered as §117 205(a)(3), addressing the commenters' suggestions In addition, language has been added clarifying that compliance with §117 205(a)(3) does not eliminate the requirement for new units to undergo NSR under Chapter 116

Inland Container Corporation commented that the current carbon monoxide (CO) emission limitation of 400 parts per million by volume (ppmv) at 3 0% oxygen (O , dry basis, in proposed §117.205(e) may not be achievable by their bark-fired boiler due to fluctuations in the moisture content, particle size, and Btu content of wood waste and bark fuel They submitted data to document that the unit is designed to operate at 5 4% O The commenter requested that wood-fired units be exempt from §117 205(e), or, if that is not possible, discussions be held to arrive at an achievable CO standard for these units

The staff has reviewed the CO and O_2 emissions data provided by the commenter and agrees that bark- and wood-fired boilers do not attain the 400 ppm CO at 3 0% O, standard. The optimum level for excess air for bark-fired boilers typically is 7.0% O The staff has revised the CO limit for bark-fired boilers to 775 ppm at 7 0% O (1000 ppm at 3 0% O_2), which represents reasonably tuned boiler performance.

Texas Eastern and Trunkline Gas Company commented on the current exemption of lean burn engines and gas turbines less than 10 megawatt (MW) capacity under §117 205(g), expressing concern that EPA could require the TNRCC to adopt NO_x RACT rules for these sources, with an implementation date of May 31, 1995 The commenters requested information on the status of these exemptions

In comments submitted in previous rounds of NO_x RACT rulemaking, EPA has stated that the rule would not be approvable until the TNRCC either adopts NO_x RACT rules for certain categories of currently exempt sources, or provides an analysis that such rules are technically and economically infeasible Currently, the TNRCC does not plan to propose additional rules in the near future for the source categories listed by the commenter Any additional NO_x RACT rules adopted at a future date would include a reasonable schedule to achieve compliance with the rule Thus, the final compliance date would necessarily be after May 31, 1995

Comments received for §117 207 Alternative Plant-Wide Emission Specifications.

EPA commented on the need for TNRCC to commit to periodic evaluations of the plant-wide averaging program in its SIP submittal to EPA in order to conform with EPA's proposed Economic Incentive Program (EIP) rules These periodic audits may correspond to the Reasonable Further Progress milestone demonstration requirements. EPA further commented that the TNRCC will need to consider the impact of forthcoming final EPA guidance on NO RACT Trading and the EIP on the §117 207 averaging rule

The staff agrees with the concept of periodic audits to ensure the validity of NO_x reductions obtained using the plant-wide emissions averaging approach These requirements may need to be addressed in future rulemaking and summarized in the SIP narrative, after clarification regarding their implementation is received from EPA

TCC/TMOGA et al and Texaco commented that the reference in §117 207(f)(3) should be changed from §117 205(a) to §117 205(b)

The staff agrees that the references in §117 207(f) are incorrect The ability to opt in a permitted unit would require that the unit have its assigned §117 207 limit be no greater than its permit limit Otherwise, the applicable emission specification for unpermitted units listed in §117 207(f) (1)-(5) are found in §117 205 The staff has revised the references at §117 207(f) to include the phrase "the lower of the emission specifications determined in accordance with §117 205(a) "

TCC/TMOGA et al and Texaco suggested that the second sentence of §117. 207(f) be revised to include boilers and industrial furnaces (BIF units) regulated under 40 CFR Part 266, Subpart H, since this equipment class was proposed for inclusion at §117 207(f)(5)

The staff agrees with the commenters and has revised §117 207(f) to list the inclusion of BIF units regulated by 40 CFR 266, Subpart H, as allowed by §117 207(f)(5)

TCC/TMOGA et al commented that the equation for "NO (allowable) " in §117 207(g)(3) should reference §117 205(c) instead of "§117 105(f) or (g)" as proposed.

The staff acknowledges this publication error inadvertently made by the *Texas Register* The staff has revised the reference in §117 207(g)(3) to read "§117 205(c)." This subsection is the correct location of the applicable NO_x emission specification for gas turbines

Comments received for §117 209 Initial Control Plan Procedures

After the period for receipt of written comments had ended, TMOGA and the Association of Texas Intrastate Natural Gas Pipelines requested a 120 day extension for certain sources with no units subject to emission specifications under §117 205 to submit an initial control plan as required by §117.209. The commenters stated that the current wording of §117.209 does not appear to require such sources to conduct NO_x emissions testing, although proposed §117.209 clarifies that such requirements do in fact apply to these sources Considering that the effective date of the newly adopted rule would be later than the April 1, 1994, deadline for submitting initial control plans, the commenters requested additional time to submit the plans.

The staff recognizes that the wording in the opening paragraph of current §117.209 appears to exempt sources with no units subject to emissions specifications under §117 205 or §117 207 from the requirement to submit an initial control plan This was not the staff's intent Although certain such emission units already are required to conduct initial control plan testing under current §117 211(c) (relating to Initial Demonstration of Compliance), the proposal was made to move these requirements to §117 209(b) for clarification

In order to give a reasonable amount of time for these sources to submit initial control plans after rule adoption, §117.520 has been revised. The requirements of §117.520(1) have been divided into three parts Subparagraph (A) requires major NO_x sources which have units subject to emission specifications under this chapter to submit an initial control plan for all such units no later than April 1, 199 : Subparagraph (B) requires major NO_x sources which have no units subject to emission specifications under this chapter to submit an initial control plan for all such units no later than September 1, 1994 Subparagraph (C) requires major NO_x sources subject to either (A) or (B) as defined above to submit the information required by §117.209(c)(6), (7), and (9) no later than September 1, 1994. It is important to note that for major NO_x sources which have both types of units (those which are subject to emission limitations and those which are not), the initial control plan due April 1, 1994, must include test results and other required information for all such units.

TCC/TMOGA et al commented that, given the work already underway to meet the April 1, 1994 due date for submitting initial control plans under §117. 209, it is too late to make substantive changes to the section The commenters recommended that any new requirements be limited to those essential to effective implementation of the regulation.

The proposed revisions to §117 209 were intended primarily to clarify the section's requirements, add references to §117.223 (Source Cap) where applicable, and to provide staff with additional information in evaluating initial control plans New requirements introduced in the current rulemaking consist of listing the following in the initial control plan: §117.209(6)- units requiring modifications to comply with §117.208 (Operating Requirements), §117 209(7)-past or anticipated shutdowns since November 15, 1990 as a result of rule compliance along with the shutdown date, and §117. 209(9)-totalizing fuel flow meters currently in operation, and statement of whether rule compliance was the reason for installation The staff has added new §117 520(1)(C) to provide an extension until September 1, 1994, for sources to submit this additional information. This will give ample time for sources that have not already provided the information with the April 1, 1994, plan to do so. The original due date of April 1, 1994, still applies for all other information and test data required in the initial control plan.

TCC/TMOGA et al. stated that the proposed language in §117.209 would require every major source of NO_x to develop a plan to install NO_x control equipment, which is inconsistent with the intent of the regulation. Texaco recommended that the references to installation of NO_x control equipment and demonstration of anticipated compliance be deleted from the first sentence of §117 209(a).

The staff partially agrees with the commenters. The intent of the regulation is not that every major NO_x source develop a plan to install NO_x control equipment, but rather that every major source submit at least a listing of NO_x-emitting sources. The requirements of §117.209 to submit an initial control plan include the requirement to list equipment expected to install NO_x control equipment and the demonstration of anticipated compliance with the regulation; the proposed language is intended to clarify these requirements. Therefore, the staff has revised §117.209(a) by adding the phrase "(if required by the emission specifications of this subchapter)" after the phrase "NO_x emissions control equipment."

Fina commented that proposed §117 209 has been revised to require emissions testing by April 1, 1994, for all units subject to the requirements of §117 211, relating to Initial Demonstration of Compliance Fina stated that §117.209(9), as adopted May 28, 1993, allowed heaters with a MRC greater than 100 MMBtu/hr to perform testing by May 31, 1995. Fina commented that this schedule change for testing requirements is unreasonable, and requested that the due date for submitting initial control plan test results be extended to June 1, 1994

The proposed revisions to Chapter 117 do not affect the schedules or applicability for heaters rated 100 MMBtu/hr or greater which are required to submit initial control plan testing under §117 209 (due April 1, 1994), or initial determination of compliance testing under §117 211 (due May 31, 1995) Existing §117.209(9), effective June 9, 1993, requires submittal of test data in the initial control plan for "each unit subject to the testing requirements of §117.211" In existing §117.211(a), testing requirements are given for units "subject to the emission limitations of §117.205...or §117.207" Process heaters rated 100 MMBtu/hr or greater are therefore included in the original rule requirement to submit initial control plan test results by April 1, 1994. As discussed elsewhere in this evaluation of testimony, due dates for submittal of initial control plan test data have been extended in certain cases. However, the staff does not consider such an extension warranted for the case presented by the commenter.

The Johnson Space Center recommended that in cases where a standby or back-up unit is identical to the primary unit in service, submission of initial control plan test results for only one unit be allowed, since emissions from identical units should be equivalent within an acceptable margin of error.

The staff's experience with "identical" pieces of equipment is that the emissions from them are not equivalent, with or without an acceptable margin of error. As an example, six ethylene cracking furnaces were tested for compliance and the testing revealed a range of NO_x emissions from 0 05 lb NO_x/MMBtu to 0.08 lb NO_x/MMBtu. This variability is large enough to warrant testing of each unit.

Units which are used as standby or back-up units may be able to claim a low annual capacity factor exemption. The low annual capacity factor units are not required to have emissions testing performed.

Texas Eastern and Trunkline Gas Company commented that the current rule proposal appears to remove the option of using portable testing equipment previously allowed in §117.211. They expressed concern about the impact on compliance testing, and requested that the TNRCC reconsider this issue

Portable analyzers were never allowed to be used for compliance determinations. Portable analyzers are only to be used for gathering the emissions test data required for the initial control plans. Initial demonstration of compliance must be performed according to the provisions of §117.211(e). The staff's intent with the proposed rule language is to clarify the required testing methods by locating the initial control plan testing requirements in the initial control plan section.

TCC/TMOGA et al. and Texaco commented that it is unnecessary and impractical for the Executive Director of the TNRCC to approve initial control plans, given the short time frame between April 1, 1994 (due date for plan submittal) and May 31, 1995 (final compliance date). They suggested language in §117 209(a) whereby a company would consider its initial control plan approved if it had not received written objections from the Executive Director within 45 days of submitting the plan.

It is important that information and test data provided in initial control plans be reviewed and approved by TNRCC staff to determine whether companies' preliminary compliance assessments and control strategies appear adequate and appropriate. Also, since data contained in the initial control plans will be used to update and enhance the emissions inventory and Urban Airshed Model (UAM) efforts, some minimum quality assurance is essential. The staff intends to conduct timely review of all initial control plans in order to accomplish these objectives, thereby giving companies sufficient advance notice of any deficiencies in their plans.

Lyondell-Citgo Refining Company Ltd. requested consideration for postponing initial control plan testing due to special circumstances at its plant Lyondell operates a reformer unit on a limited basis and as back-up during a magnaformer unit's turn-arounds which occur every two years The commenter stated that it would cost an estimated $500,000 to start up the reformer solely to perform testing by April 1, 1994, and requested an allowance in the rule to permit testing when the unit is brought on line during the second quarter of 1994. Lyondell said that the reformer unit was last operated during the second quarter of 1993, before the TNRCC's Test Method Protocol guidance document was issued on September 3, 1993.

The staff agrees with the commenter about the difficulty of emissions testing equipment which is not operational. However, the unavailability of the Test Method Protocol until September 3, 1993, would not specifically hinder a company from obtaining emissions test results in time to submit the data with the initial control plan due April 1, 1994.

The staff has revised §117.209(b) to allow equipment which has not been in operation since the effective date of the original adoption of §117.209 (June 9, 1993) to be tested and the results submitted within 90 days after the equipment is brought back into operation. Certification of the equipment's shutdown period must also accompany the test results.

TCC/TMOGA et al. commented that proposed §117.209(b), by referring to §117.211(e) and (f), allows three one-hour emission test runs if EPA test methods are used instead of portable analyzer methods. They noted that the TNRCC's Test Method Protocol guidance document, dated September 3, 1993, allows three 20-minute tests regardless of whether portable analyzer or EPA test methods are used. They recommended that §117.209(b) be revised to allow substitution of three 20-minute tests for three one-hour tests using portable analyzers. Texaco recommended that proposed §117.209(b) be revised to allow alternatives to portable analyzer and reference method testing due to the shorter test times done by some testing contractors using EPA test methods.

The staff agrees with the substance of the comments made by Texaco, TCC/TMOGA, et al. However, allowing three 20-minute test runs for the initial control plan testing requirements means that the data collected are not acceptable for the initial demonstration of compliance for a unit. The Test Method Protocol was revised on January 21, 1994, to address the concerns of Texaco, insofar as alternatives to portable analyzer and reference method testing were recognized.

The staff has revised §117.209 to include the phrase "or reference method" directly following the word "portable" in the first sentence of §117. 209(b) to address these concerns.

DuPont commented on the TNRCC staff interpretation that flares with MRC greater than 50 MMBtu/hr heat input should be listed in the initial control plan. DuPont suggested that, since flares most likely will not be controlled under the rule, and flare emissions are already reported in the TNRCC emissions inventory, language be added to §117.209(c)(1) excluding flares from initial control plan requirements. Exxon commented that any emission unit, including flares, exempted from NO_x emission specifications should not require listing in the initial control plan

The requirements in proposed §117.209 for exempted emission units, including flares, are minimal, as such units need only be listed in the initial control plan The listing threshold of 5.0 MMBtu/hr heat input, as applied to flares, refers to normal design heat input. Emergency release heat input for a flare, which is substantially greater than normal design heat input, is not considered in defining MRC. The staff believes that these requirements are useful and valid, therefore they have been retained in §117 209.

TCC/TMOGA et al commented on the proposed requirement in §117 209(c)(6) for companies to list in the initial control plan all units requiring operating modifications under proposed §117.208(d), the type of modifications to be applied, and an anticipated construction schedule. They stated that since §117.208(d) requires compliance by May 31, 1995, and it is too late to modify initial control plan requirements at this time, the proposed requirement serves no useful purpose and should be deleted in the final rule.

The proposed requirement cited by the commenters will provide useful information to TNRCC staff in evaluating compliance strategies and in developing future rules The staff has added new §117 520(1)(C) to provide an extension until September 1, 1994, for sources to submit information required in §117 209(c)(6), (7), and (9) The original due date of April 1, 1994, still applies for all other information and test data required in the initial control plan

TCC/TMOGA et al commented that proposed §117 209(c)(7) should not require a listing in the initial control plan of all units that have been shut down, regardless of the reason They recommended revising the rule to require listing only those shutdown units which ceased operation as a result of compliance with the regulation, and suggested adding a reference to the anticipated shutdown date for clarity

The staff agrees with the commenters, and has revised §117 209(c)(7) as suggested In addition, language was added stating that such shutdowns occurring after November 15, 1990, are required to be listed in the initial control plan

TCC/TMOGA et al stated that proposed §117.209(c)(9), requiring companies to list in the initial control plan the totalizing fuel flow meters installed by April 1, 1994, and to state whether the devices were installed as a result of the rule, is not clear in its intent They recommended deletion of this proposed requirement

The staff's intent is to determine whether or not the totalizing fuel flow meters have been installed to aid the companies in performing the emissions testing (since fuel flow rates can be used to calculate the exhaust flow rate which can then be used to calculate the mass emissions rate for NO_x) The totalizing fuel flow meters do not have to be installed by April 1, 1994 The only rule requirements are to list the meters that are currently operating, and to identify whether the installation was performed as a result of the rule Since there had been no initial control plans received by the date of the rule proposal, the additional requirement of listing the installed fuel flow meters cannot be considered to be burdensome. Changes to §117. 209(c)(9) have been made to clarify the requirement.

Comments received for §117 211 Initial Demonstration of Compliance.

TCC/TMOGA et al. and Texaco recommended that, for clarity, proposed §117. 211(e) contain a reference to the source cap compliance option under §117. 223.

The staff agrees with the commenters since §117 223 specifies that §117 211(e) is used to establish the emission limit for units not using a CEMS or PEMS. A change has been made in §117 211(e) to include a reference to §117. 223.

TCC/TMOGA et al recommended language in proposed §117.211(e) which would give companies the option to test at less than MRC for units operating without CEMS or PEMS. For companies electing this option, they suggested limiting the operating rate for such units to 110 percent of the operating rate during testing. EPA commented that since emissions testing at MRC is required by §117.211(e) and (f), these subsections should be revised to prohibit a source from operating above the level at which it demonstrated compliance during the initial determination of compliance test.

The staff disagrees with TCC's proposal to generally allow testing at less than MRC EPA and the TNRCC staff are concerned that artificial claims of MRC can reduce or eliminate the need to make emission reductions, defeating the purpose of the rule. With multiple emission tests necessary to demonstrate plant-wide average emission compliance, the effect of inflated MRC's is multiplicative. For instance, allowing testing to be conducted at 90% of MRC or more could eliminate the need to make emission reductions at a plant which otherwise would be required by rule to make a plant-wide 10% NO_x emission reduction. This is why compliance testing is required to be conducted at MRC.

However, the staff also disagrees with EPA's recommendation that if a unit was tested at a heat input below its MRC, the unit would not be allowed to operate above its test level Situations may arise which make testing at MRC impractical for a limited time period. Some types of equipment, such as gas turbines, are dependent upon ambient conditions to achieve MRC The operator does not have control over ambient conditions and it is impractical to schedule testing to coincide with extreme ambient conditions. It also may be impractical, costly, and result in higher emissions to require operation with alternative liquid fuels simply to demonstrate initial compliance. The rule currently specifies that testing shall occur "at the MRC or as near thereto as practicable " This statement means that testing at less than MRC is not justified unless it can be shown to be the only practicable option at the time

Language has been added to require retesting at MRC (within 90 days after exceeding the heat input of the initial demonstration of compliance test, or one year after the initial demonstration of compliance test, whichever comes first), if the reason for not initially testing at MRC was not due to ambient conditions. The adopted rule allows flexibility to either assign an MRC which is readily achievable (sufficient to conduct testing at that level) prior to the initial demonstration of compliance date, or to assign a higher MRC which, nevertheless, must be achieved in a definite time period. Units which do not achieve MRC during the initial test must be tested again within one year at MRC.

EPA commented that any alternate methods allowed in proposed §117 211(e) (5) should also be approved by EPA.

The staff agrees with the commenter. The methods cited in §117.211(e)(5) pertain to fuel composition and calorific value; the EPA Administrator has the authorization in 40 CFR §60.13(i)(7) to approve alternate methods to American Society of Testing and Materials (ASTM) test methods that are specified by any subpart of 40 CFR 60. The staff revised §117 211(e)(5) by adding the phrase "and the EPA" after the phrase "Executive Director."

TCC/TMOGA et al. recommended changing citations of the ASTM methods in proposed §117.211(e)(5) to reflect the most recent revisions of these methods.

The staff cannot incorporate other rules, standards, or other guidance by reference. Any new revisions to the ASTM methods can be updated and included in later rulemaking. The proposed language does allow for alternate methods, as approved by the Executive Director and the EPA. A newer revision to the listed ASTM test methods would come into this category. The most recent revisions are D1945-91, D2650-93, and D3588-91 according to the *Annual Book of ASTM Standards*

References to the three ASTM test methods have been updated The staff also clarified that ASTM D3588-91 is for the purpose of determining the calorific value and relative density of gaseous fuels, and added a fourth ASTM test method to determine the gross calorific value, D1826-88 entitled Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter.

EPA recommended deletion of language in proposed §117 211(e)(6) which would allow minor modifications to EPA-approved alternate test methods.

The staff disagrees with the commenter. The need for minor modifications of EPA test methods exists. Emissions testing of 1,600 units requires some flexibility in the application of test methods to this sizable number of units operating in their real world environments. Previous comments addressing this subject in earlier rule proposals have requested that there be flexibility in using modified test methods and for the inclusion of references to new, EPA-approved test methods

The staff has worked with EPA to address these concerns, and has revised §117.211(e)(6) to include language providing criteria for allowing minor modifications.

TCC/TMOGA et al. suggested replacing the word "units" in proposed §117. 211(f)(2) with the specific equipment categories of boilers, process heaters, and gas turbines.

The staff agrees with the commenters. The suggested revision clarifies the term "unit" in this paragraph, since the affected equipment is limited to boilers, process heaters, and gas turbines. The staff revised §117 211(f)(2) by replacing the term "unit" with the phrase "boilers, process heaters, and gas turbines."

Comments received for §117 213 Continuous Demonstration of Compliance.

TCC et al. expressed support for the proposal to extend the use of PEMS beyond the source cap option to the compliance options contained in §117.205 (individual unit emission specifications) and §117 207 (alternative plant-wide emission specifications)

The staff acknowledges the support of the commenters. See the related comment by GHASP in the General Comments section

Applied Automation, Inc. commented on the distinctions between performance validation of CEMS compared to PEMS, stating that the existing certification requirements in the rule should not be relaxed until PEMS equivalency can be demonstrated Applied Automation recommended that validation procedures be developed and made part of PEMS operational requirements.

PEMS is a new and promising technology that has yet to demonstrate its reliability over an extended length of time The staff will constantly reevaluate the existing certification requirements of PEMS as the technology continues to demonstrate equivalence in performance and reliability to that of hardware CEMS. PEMS operators are required to develop a quality assurance and control manual for PEMS which includes daily, quarterly, and semiannual or annual assessment procedures to ensure continuous and reliable performance.

EPA recommended that the phrase "and operating" be added in the second sentence of proposed §117 213(a), after "The O_2 monitors and totalizing fuel flow meters shall be installed..."

The staff agrees with the commenter and has revised §117 213(a) by adding the phrase "and operating" after the phrase "The O monitors and totalizing fuel flow meters shall be installed" in the second sentence of §117.213(a).

EPA commented that the TNRCC must supply technical justification for the deletion of the annual relative accuracy test audit (RATA) requirements of 40 CFR Part 60, Appendix F, Section 5.1.1, and substitution with a cylinder gas audit, in proposed §117.213(b).

The staff's decision to allow substitution of the annual RATA with a cylinder gas audit check was based on discussions with the monitoring operations staff of the TNRCC which indicated that daily calibration and quarterly cylinder gas audit checks are satisfactory to ensure accurate and reliable performance of hardware CEMS. Since the proposed enhanced monitoring rules (40 CFR 64) reference 40 CFR 60, Appendix F in its entirety, the staff will reevaluate its decision in view of the final enhanced monitoring regulations and address this issue in the SIP narrative of the next round of NO_x RACT rulemaking.

TCC/TMOGA et al and Texaco recommended wording changes to proposed §117. 213(c) to reflect that PEMS predicts rather than measures emissions, and to clarify that PEMS may be used to predict one or more gaseous components of the waste gas stream, with CEMS used to measure the remainder of the components

The staff agrees with the commenters that a PEMS predicts pollutant emissions and does not directly measure the gaseous concentration The staff also agrees with the commenters that any combination of PEMS and CEMS may be used to determine the levels of the gaseous components in the exhaust stream Section 117 213(c) was revised to include the recommended wording.

GHASP commented that the term "substantially equivalent" in proposed §117 213(c)(1) should be defined to avoid subjective interpretations of its meaning

Section 117 213(c)(1) allows the PEMS operator to propose alternatives to 40 CFR 75, Subpart E if such procedures are demonstrated to the satisfaction of the Executive Director to be substantially equivalent to the requirements of 40 CFR 75, Subpart E The term "substantially equivalent" is not defined, since each proposed alternative will have to be evaluated on its own merits

EPA recommended that proposed §117.213(c) be revised to clarify that any alternative methods to CEMS or PEMS for measuring O_2 or CO also need to be approved by EPA EPA further commented on the need for EPA approval of alternative methods or nonapplicability determinations under §117 213(c)(1) and (2) The staff agrees with the commenter as to the EPA's need to review and approve any alternative methods to PEMS or CEMS, or alternative methods or nonapplicability determinations under §117 213(c)(1) and (2)

The staff revised §117 213(c) to add the requirement that EPA approve any alternative methods to PEMS or CEMS for measuring O or CO , alternative methods to 40 CFR 75, Subpart E, or nonapplicability determinations of the requirements of 40 CFR 75, Subpart E

TCC/TMOGA et al and Pavilion Technologies, Inc. (Pavilion) stated that performing RATA procedures at three load levels as required by proposed §117. 213(c)(3)(A)(i) may not accomplish the desired effect of testing over a range of NO_x emissions They recommended language which would allow the company to identify the most important control parameter affecting NO_x emissions, and to perform RATA tests at three different levels (low, medium, and high) of this parameter. TMOGA, et al. recommended RATA testing at low, medium, and high levels of historical operating rates

The staff agrees that basing RATA testing on the key operating parameter affecting NO_x emissions would be a better indicator of PEMS performance, and has revised the rule language of §117 213(c) accordingly. The staff disagrees with TMOGA, et al, with regard to allowing RATA testing at low, medium, and high levels of historical operating rates. Historical operating rates do not necessarily guarantee testing of the performance of PEMS.

TCC et al. and Pavilion stated that the statistical tests required in proposed §117.213(c)(3)(A)(ii) are redundant, burdensome, and expensive, as the new technology of PEMS is held to more stringent RATA standards than CEMS, the established technology, can meet. They recommended that the statistical tests be eliminated entirely, since such requirements are not contained in EPA's proposed enhanced monitoring regulations.

The staff disagrees with the commenters. Parametric modeling generally falls into two main categories. The first category relies on physical principles which employs analytical methods to describe the dynamics of the process These methods are derived from the physical equations or the laws of nature that govern the system. This category of models is generally expressed in nonlinear partial differential equations that are solved via numerical analysis techniques, as these equations are often too complicated to be solved via standard analytical methods Errors are introduced into this category of models either by the assumptions made in simplifying the governing equations so they can be solved by standard analytical methods, or by the numerical discretization (approximation) of the nonlinear equations

The second category of models relies on linear or nonlinear regression analysis or curve fitting of historical data. These models mainly rely on computer software which, with the use of high quality historical data, interpolates and/or extrapolates over a wider range of operating conditions, or learns the dynamics of the process by developing statistical multivariable mathematical functions that mask the dynamics of the process

These models do not rely on physical principles, nor do they guarantee long-term imitation of the actual dynamic process which is usually better represented when physical principles are applied.

The staff observed good model performance from both categories of models and decided to allow the use of any category of PEMS as long as it can demonstrate equivalent accuracy, precision, reliability, accessibility, and timeliness to that of hardware CEMS. Accuracy is demonstrated by a relative accuracy test audit Precision is demonstrated via performing statistical analysis Since PEMS accuracy and precision may not necessarily be accurately evaluated by relying on analytical methods, the staff decided to use a statistical approach in evaluating precision of the system. This approach is used in 40 CFR 75, Subpart E, which requires utility boilers to monitor NO_x and SO_x emissions under Title IV of the 1990 FCAA.

Three statistical tests are required, The first is a t-test, designed to determine existence of any systematic error (bias) in the PEMS and provide a mechanism to adjust for that error The second test is the F-test, which is a statistical procedure designed to determine if both PEMS and hardware CEMS (or EPA-certified test method) have equal variability on the basis of chance. Thus, it specifically addresses random error of the PEMS and assures comparable random variations between the two systems. The third test is the correlation test, designed to determine how well the PEMS is able to track the hardware CEMS (or EPA test method) over time. It accounts for process changes and determines if the PEMS is able to respond properly to changes in operating conditions. The staff believes that all these statistical tests are important in evaluating the system, as each investigates the existence of a different type of error

As stated by the commenters, no statistical testing is required under the proposed enhanced monitoring program. It should be pointed out, however, that the program is designed to demonstrate continuous compliance with applicable emission limitations or standards, with less emphasis on precision and accuracy of measurements. Air quality planning will always rely on emissions inventories for development of new control strategies Measuring emissions accurately and demonstrating continuous compliance are both necessary, especially in ozone nonattainment areas or areas where marketable emissions trading is likely to be implemented

Several commenters suggested certain changes to the statistical test requirements of §117 213(c)(3)(A)(ii) to make them more workable These recommended changes are summarized in the comments which follow.

TCC, Pavilion, and HL&P recommended requiring only an r-correlation test using data from all three different ranges of the chosen control parameter. TMOGA, et al recommended performing the F-test, t-test, and correlation analysis, but at low, medium, and high levels of historical operating rates. TCC, Pavilion, and HL&P recommended removing the requirement for a bias test (t-test) to be performed at each load (control parameter) level, and requiring the t-test only at the normal parameter range. TCC and Pavilion commented that PEMS certification should be approved if the statistical tests are failed but the RATA tests are passed.

The staff disagrees with the commenters to require a correlation test only. The correlation test is important because it evaluates how well both the PEMS and the CEMS (or EPA reference method) are able to track each other and respond to changes in operating conditions over time. The correlation test alone, however, is not satisfactory to demonstrate precision of the PEMS. Moreover, when applied using all data points collected at all three tested levels, the correlation test's value as a good screening tool is diminished, even for investigating transient changes of process operating conditions. Uncorrelated data samples at each level are masked out by the overall pattern of the data distribution at all levels A weighted correlation test that is dependent on the local mean of each level is a much better representative measure of correlation Since data variability at each tested level is a combination of random variability and process variability, the staff has found it is difficult to pass a weighted correlation test on data collected over a short period of time and instead, and has thus allowed the option of performing the less stringent correlation test using all data collected at all levels.

Each data sample is characterized by its mean, standard deviation (average variability about the mean), and correlation. The relative accuracy test measures the significance of the difference between two sample means, taking into account that some difference may be attributable to chance. The F-test is a measure of the difference between the standard deviations of two different sample means on the basis of chance. It is designed to guarantee comparable variability between the two samples. The correlation test measures the correlation between the two samples. Thus, the relative accuracy test, the F-test, and the correlation test are all important in characterizing the quality of a sample.

The staff believes that testing at low, medium, and high levels of historical operating rates may not necessarily test the performance of the PEMS. PEMS operators are allowed to specify the operating range of each parameter including the key operating parameter, but must guarantee future operation within the specified operating ranges. Future operations outside the operating range of any parameter would necessitate either recertification or additional testing of the PEMS

The t-test is designed to determine the existence of systematic errors (bias) in the system and provides an adjustment mechanism for that error. Applying the t-test at each tested level would result in development of three adjustment factors. Rather than applying the t-test at the normal load level, staff recommends applying the t-test using all the data collected at all tested levels. This results in the development of one adjustment factor that can be applied to the system. For these reasons, the staff disagrees with the comment that PEMS certification should be approved if the statistical tests are failed but the RATA tests are passed.

TCC and Pavilion recommended revising the statistical tests defined in 40 CFR 75, Subpart E as follows: since the F-test is mathematically flawed if the standard deviation is zero, use three parts per million (ppm), a reasonable hardware standard, as the lower level of precision, and the precision of small measured values using reference methods is unsuitable because instrument noise dominates at these low ranges, making statistical conclusions meaningless Waive the statistical test requirement if the average reference method emission rate is less than 5.0% of the emission standard, or 10 ppm, whichever is higher.

With regard to the first comment, the staff agrees with the commenters and has made the recommended change in the draft PEMS Guidance Document. Instead of three ppm, the guidance now specifies five ppm or 3.0% of span, whichever is higher, as the lower level of precision With regard to the second comment, the staff agrees with the commenters and has made the recommended change in the draft PEMS Guidance Document. The decision to waive statistical tests when the mean is below the cutoff level is applied separately to each tested level.

TCC, Pavilion, and HL&P commented that the requirement for "successive" data points with no allowance for data breaks may result in the use of costly redundant analyzers. They recommended allowing the use of RATA data within an acceptable downtime for reference method analyzers, defined as no more than one averaging period (20 or 60 minutes, as appropriate).

The staff agrees with the commenters. The draft PEMS Guidance Document has been revised to allow RATA data to be used as part of the statistical data. Staff and industry have agreed to increase the data collection requirement from 24 data points to 30 data points. The first nine data points of the required 30 are for the RATA, to be collected at intervals which allow time for calibration. The remaining 21 data points, which can be either 15-minute, 20-minute, or hourly averages, are to be collected continuously without calibration breaks.

TCC and Pavilion commented that, to be consistent with 40 CFR 75, Subpart E provisions, statistical tests should be required for PEMS initial certification only, with RATA tests every six-12 months thereafter. HL&P recommended that statistical tests be required for initial certification only, unless the PEMS is unable to pass the quarterly RATA tests in the first year of operation.

The staff disagrees with the commenters. The PEMS certification procedure of 40 CFR 75, Subpart E requires data collection of 720 paired hourly averages. The data sample is used for statistical evaluation of the performance of the PEMS by comparing it with the performance of a hardware CEMS. The excessive data collection requirement is aimed at providing performance evaluation of the PEMS over a sufficient time period to include load variability and operating and seasonal conditions. The staff found this data collection requirement impractical, and developed a more cost-effective approach that addresses these concerns. The staff's approach accelerates the experiment by forcing the occurrence of these variations over a much shorter testing period. Thirty paired data points, which can be either 15-minute, 20-minute, or hourly averages, need to be collected only at high, medium, and low test levels of the key operating parameter. Varying the key operating parameter over a short time provides satisfactory insight into PEMS response to variations in operating conditions. Reducing the testing period from 30 days to three days (if hourly averages are used) would not, however, allow for performance evaluation of the PEMS at different seasonal conditions. The 30-day data collection period required by Subpart E is long enough to allow some seasonal variations to be observed and evaluated.

The staff decided that reducing the testing period from 30 days to three days (one day if 20-minute averages are used) must be accompanied by additional requirements to test PEMS performance at different seasonal conditions. Quarterly statistical evaluation of the PEMS was added to address this concern. To ease the burden of performing these tests, the staff has limited quarterly statistical evaluation requirements to a single unit in a given equipment category, and to no more than one year after initial certification. The staff believes this requirement is necessary since the three-day testing period does not allow for PEMS performance evaluation at different seasonal conditions.

A source which finds this additional requirement excessive has the option of using the certification procedure of 40 CFR 75, Subpart E in its entirety as an alternative. Affected sources not subject to 40 CFR 75 are allowed to choose either the certification procedure of §117.213(c) or 40 CFR 75, Subpart E. Once a choice is made, affected sources must be consistent in following the certification requirements of the chosen approach.

GHASP commented that under proposed §117.213(c)(3)(B)(i), all units must perform RATA and statistical tests to ensure compliance.

The staff disagrees with the commenter. The quarterly RATA and statistical tests required by §117.213(c)(3)(B)(i) are part of the initial certification and aimed at demonstrating that the PEMS could provide accurate predictions at different seasonal conditions. It is too costly to require these tests to be conducted every quarter, and on all units. If the PEMS for one unit in a category of units could demonstrate accuracy and reliability at different seasonal conditions, it is expected that PEMS serving other units of the same category are capable of providing comparable performance.

TCC/TMOGA et al. and Texaco recommended clarifying wording in proposed §117.213(c)(3)(B)(ii), concerning alternative fuels whose composition routinely varies. They suggested language requiring PEMS certification only for each alternative fuel which exceeds the modeled input range.

New §117.213(c)(3)(B)(iii) has been added to address this comment. PEMS does not need to be recertified if fuels of different compositions were considered as a parameter variable and addressed in the modeling process. Recertification will only be required for fuel compositions outside the modeled range.

HL&P commented that proposed §117.213(c)(3)(B)(ii), which requires separate PEMS certification for each alternative fuel, would adversely affect gas turbines which fire fuel oil only during emergency situations and monthly test procedures. The commenter requested that gas turbines be exempt during periods of fuel oil firing by applying the 850 hours per year exemption criterion for low annual capacity factor units to the period the unit actually fires fuel oil. Alternatively, TNRCC could amend §117.213(c)(3)(B)(ii) to allow PEMS certification based on all fuels for which models are trained.

The staff has decided to allow certification of PEMS for a range of fuels or fuel compositions provided that the PEMS was trained over that range. The staff agrees with the second alternative proposed by the commenter and has made the recommended change at new §117.213(c)(3)(B)(iii)

TCC/TMOGA et al. stated that the proposed requirement in §117.213(d)(1) for BIF units to install totalizing fuel flow meters is not justified in terms of NO_x emissions reductions, since these units are exempt from emissions specifications. Moreover, the variable nature of the hazardous waste fuels creates technological and economic limitations to the effective fuel flow measurements. They recommended deletion of this proposed requirement.

The staff partially disagrees with the commenters, regarding deletion of the requirement in §117.213(d)(1) to install totalizing fuel flow meters on BIF units. BIF units, among others, are not totally exempt from the rule's requirements; the fuel flow data are important for air quality planning purposes and future rulemaking. The staff's intent is that the requirement to install totalizing fuel flow meters applies only for natural gas, process fuel gas, refinery fuel gas, and fuel oil used for primary or supplemental firing. The staff would like to point out that 40 CFR §266.103 requires monitoring and recording the feed rates and composition of hazardous waste, other fuels, and industrial furnace feed stocks. Therefore, the requirements to install totalizing fuel flow meters have been changed to require that totalizing fuel flow meters be installed only for the stated gaseous fuels and fuel oil in §117.213(a)-(d).

TCC/TMOGA et al recommended that the requirement in proposed §117.213(d) (3) for lean-burn engines to install totalizing fuel flow meters should exclude low annual capacity factor engines

The staff agrees with the commenters since the low annual capacity factor status for lean-burn engines is required to be demonstrated using elapsed run time meters in accordance with §117.213(g). The staff revised §117.213(d) (3) to exclude lean-burn engines operated less than 850 hours per year.

TCC/TMOGA et al. recommended that the requirement in proposed §117.213(d) (5) for fluid catalytic cracking unit (FCCU) boilers to install totalizing fuel flow meters be deleted because these units are already exempted from emissions specifications in the rule.

The staff's intent is that the requirement to install totalizing fuel flow meters applies only for natural gas, refinery fuel gas, process fuel gas, and fuel oil used for primary or supplemental firing in a FCCU CO boiler Therefore, the staff revised the requirements to install totalizing fuel flow meters only for the stated fuels in §117.213(a)-(d)

TCC/TMOGA et al. stated that the provision in proposed §117.213(g) for the Executive Director to approve elapsed run time meters serves no useful purpose and should be eliminated from the rule.

The staff partially agrees with the commenters. The staff is aware that most of the elapsed run time meters which are available would suit the purposes of the requirements in §117.213(g)

The importance of the quality of the meters (in demonstrating low annual capacity factor status) would dictate that the meters meet certain standards. The standards for totalizing fuel flow meters and elapsed run time meters are expected to be developed by the TNRCC staff for the Title V Enhanced Monitoring requirements. At this time, however, the approval of the elapsed run time meters is not warranted The requirement for approval of the elapsed run time meters in §117.213(g) has been deleted as a result.

TCC/TMOGA et al. suggested changing the language in proposed §117.213(h) to reflect the most recent revisions of the listed ASTM methods. EPA commented that alternative test methods must also be approved by EPA.

The ASTM methods have been updated and the requirement for EPA approval has been added to §117 213(h).

EPA suggested replacing the last sentence of proposed §117.213(i) with the following. "For enforcement purposes, the Executive Director may also use other TNRCC compliance methods to determine whether the source is in compliance with applicable emission limitations" EPA commented that this change would clarify that the TNRCC may require compliance determinations by alternate methods

The staff agrees with the commenter, since the suggested language clarifies without changing the intent of the sentence. The staff has replaced the last sentence of §117.213(i) with the language suggested by EPA.

Comments received for §117.219 Notification, Recordkeeping, and Reporting Requirements.

Rohm and Haas Texas Incorporated commented on the requirements in proposed §117 219(d)(1) for gas turbines using steam-to-fuel (or water-to-fuel) ratio monitoring to submit quarterly excess emission reports. Reports are required for any one-hour period in which the steam-to-fuel ratio is less than that level determined by testing at MRC to result in compliance. The commenter stated that variations in turbine load will change the steam-to-fuel ratio necessary to maintain compliance, resulting in incorrect levels of steam injection just to maintain the steam-to-fuel ratio at levels corresponding to MRC operating conditions. In order to remedy this situation, the commenter recommended revising the rule to require reporting those one-hour periods when the average steam or water injection rate is below the level determined necessary by the control algorithm.

The staff agrees that steam-to-fuel or water-to-fuel ratios need not be consistently maintained at MRC compliance levels in order to ensure compliance with the rule's emission limitations for gas turbines. Language in §117. 219(d)(1) has been revised to reflect that 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. New language in §117.213(f)(2) requires Executive Director approval of steam or water injection control algorithms. Section 117.208(d)(4) already requires steam or water injection rates to be maintained to limit NO_x concentrations to less than or equal to the NO_x concentrations achieved at MRC

Comments received for §117.223 Source Cap.

Energy Technology Consultants Inc. requested clarification of the distinction between "equipment category" in §117.223(a) and "equipment class." The specific example given was a crude heater and a coker preheat furnace operating in a refinery, and whether one of these units could be opted into the source cap without including the other.

The requirement that any equipment category brought into the source cap must include all emission units belonging to that category precludes shifting production to units outside the cap, which could compromise equivalency with unit-by-unit RACT. As defined in the rule, equipment categories include steam generation, electrical generation, and units with the same product output, such as ethylene cracking furnaces. In this sense, there is no real distinction between "equipment category" and "equipment class." The possibility for production to be shifted to non-cap units is the main criterion that will be applied in determining which units can be selectively opted into the source cap.

GHASP commented that the term "achieving equivalent nitrogen oxides emissions reductions" in proposed §117.223(a) should be defined to avoid subjective interpretations. GHASP objected to bubble-like strategies like the source cap, stating that they do not achieve sufficient emissions reductions.

Although the referenced term is not defined in the proposed rule, the staff intended that it mean "achieving the same nitrogen oxides emissions reductions." Strict adherence to EPA trading guidance throughout the development of the source cap rule has helped assure that RACT-equivalent NO_x reductions occur through use of the source cap.

TCC/TMOGA et al. and Texaco suggested revising the definition of "actual heat input" in §117.223(b). The commenters recommended clarifying language, and suggested allowing alternate methods for calculating the actual heat input, with Executive Director approval, in cases where data documenting daily heat input for 24 consecutive months are not available.

The phrase "average daily" has been added before "heat input" at its second occurrence in the definition in order to clarify the language. With regard to the second comment, there may be cases in which detailed fuel usage records are not available for each unit participating in the source cap. The calculation of representative actual heat inputs is crucial to the use of the source cap as a RACT-equivalent averaging method. Therefore, approval of other calculation methods could be granted by the Executive Director only upon a demonstration that such methods produce equivalent, representative heat input values. The definition of "actual heat input" has been revised to allow alternate calculation methods as suggested by the commenters.

In addition, the term "H_i" has replaced "Actual heat input" in the equation in §117.223(b)(1), and the term "H_M" has replaced "Maximum daily heat input" in the equation in §117.223(b)(2). Units have been added in the definitions of H_i and R_i. These revisions were made to remain consistent with the terminology proposed in §117.570, relating to Trading, in separate rulemaking.

GHASP commented that in proposed §117.223(e), allowing a company 48 hours to report an exceedance of the source cap emission limit is too lenient, and recommended that the rule require reporting immediately (within three hours of exceedance).

The staff believes that 48 hours is a reasonable period of time in which to record and report exceedances of the source cap emission limit. The consequences of rule noncompliance are not alleviated regardless of the time allowed for reporting exceedances, and the staff sees no useful purpose in requiring such information to be reported immediately.

GHASP stated opposition to the inclusion of retired or decommissioned units in the source cap. The commenter pointed out an apparent rule inconsistency, in that §117.223(g) requires that participating units be permanently retired, whereas §117.223(g)(5) allows inclusion of units which have not been permanently retired. Texaco commented that a company using the source cap should be able to benefit from shutdowns occurring after June 9, 1993, and recommended deleting language in proposed §117.223(g) limiting the use of shutdown credits to units removed from service prior to June 9, 1993.

The restricted use of retired or decommissioned units in the source cap offers companies a greater degree of flexibility in achieving RACT-equivalent emission rates, while meeting EPA guidelines for alternative methods of RACT control. The apparent inconsistency has been resolved by moving §117.223(g) (5) to new subsection (h), and renumbering the subsequent subsections as (i) and (j). Current §117.223(g)(6) has been renumbered as (g)(5). With regard to Texaco's comment, the wording "after June 9, 1993" has been added to new §117.223(h). After this date (effective date of the rule), there are no limitations on the operating status of units participating in the cap, as long as the total cap emission limit is not exceeded. Therefore, a unit which operates at reduced rates, or not at all, can provide credit to other units participating in the source cap.

Pavilion commented that the provision in §117.223 allowing PEMS to be used as a backup when a CEMS is off-line should be included in §117.113 and §117.213 as well.

For source cap units equipped with CEMS, proposed §117.223(c)(2) requires emissions data to be collected for compliance purposes when the CEMS are off-line, using either PEMS or the maximum emission rate established by prior approved testing. This requirement is necessary to determine compliance with the source cap emission limit while one or more CEMS are off-line. Units subject to individual emission limitations which use CEMS under §117.113 or §117.213 are not required to provide backup data when CEMS are inoperative. Therefore, this requirement has not been extended to other rule sections.

Comments received for §117.510 Compliance Schedule for Electric Utility Generation.

HL&P and Gulf States commented on the requirement in proposed §117.510(2) for affected sources to install and certify CEMS or PEMS by January 1, 1995, which corresponds to the compliance date under the federal Title IV acid rain regulations. The commenters stated that, although most utility units are required to install NO_x monitoring systems under the Title IV regulations, other units such as auxiliary boilers and units less than 25 MW are not. Also, the federal rules do not require installation of CO monitors. HL&P and Gulf States recommended that the compliance date in §117.510(2) be changed to May 31, 1995, to remain consistent with §117.510(3) for utilities and §117.520 for industrial sources, which specify a final compliance date of May 31, 1995.

The staff agrees with the commenters and has revised §117.510(2) according to the commenters' suggestion.

Subchapter A. Definitions

• 30 TAC §117.10

The amendment is adopted under the Texas Health and Safety Code (Vernon 1992), the Texas Clean Air Act (TCAA), §382.017, which provides the TNRCC with the authority to adopt rules consistent with the policy and purposes of the TCAA.

§117.10. Definitions. Unless specifically defined in the Texas Clean Air Act or the General Rules of this title, 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.

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

Electric power generating system–All boilers, steam generators, auxiliary steam boilers, and gas turbines used in an electric power generating system which are owned or operated by a municipality or a Public Utility Commission of Texas regulated utility that are located within the Houston/Galveston or Beaumont/Port Arthur ozone nonattainment areas.

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.

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.

Low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit-A commercial, institutional, or industrial boiler; process heater; or gas turbine supplemental waste heat recovery unit with maximum rated capacity:

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

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

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.

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.

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 average activity levels to the total maximum rated capacities sum of average activity levels 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.

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.

Unit-Any boiler, steam generator, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section, which is either:

(A) placed into service prior to November 15, 1992; or

(B) placed into service after June 9, 1993 as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter and limited to the cumulative maximum rated capacity of the units replaced.

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on May 25, 1994.

TRD-9441676 **Mary Ross McDonald**
Director, Legal Division
Texas Natural Resource Conservation Commission

Effective date: January 4, 1994

Proposal publication date: June 23, 1994

For further information, please call: (512) 239-0615

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Subchapter B. Combustion at Existing Major Sources

Utility Electric Generation

- **30 TAC §§117.103, 117.105, 117.107, 117.109, 117.111, 117.113, 117.115, 117.117, 117.119, 117.121**

The amendments are adopted under the Texas Health and Safety Code (Vernon 1992), the Texas Clean Air Act (TCAA), §382.017, which provides the TNRCC with the authority to adopt rules consistent with the policy and purposes of the TCAA.

§117.103. Exemptions.

(a) (No change.)

(b) Units exempted from the provisions of this undesignated head (relating to Utility Electric Generation), except for §117.109(b)(1) of this title (relating to Initial Control Plan Procedures) and §117.113(h) of this title (relating to Continuous Demonstration of Compliance), include the following:

(1) (No change.)

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

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

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

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

(c) The fuel oil firing emission limitation of §117.105(c) or §117.107(b) of this title (relating to Emission Specifications and Alternative System-Wide Emission Specifications) shall not apply during an emergency operating condition declared by the Electric Reliability Council of Texas or the Southwest Power Pool, or any other emergency operating condition which necessitates oil firing. All findings that emergency operating conditions exist are subject to the approval of the Executive Director. The owner or operator of an affected unit shall give the Executive Director and any local air pollution control agency having jurisdiction verbal notification as soon as possible but no later than 48 hours after declaration of the emergency. Verbal notification shall identify the anticipated date and time oil firing will begin, duration of the emergency period, affected oil-fired equipment, and quantity of oil to be fired in each unit, and shall be followed by written notification containing this information no later than five days after declaration of the emergency. The owner or operator of an affected unit shall give the Executive Director and any local air pollution control agency having jurisdiction final written notification as soon as possible but no later than two weeks after the termination of emergency fuel oil firing. Final written notification shall identify the actual dates and times that oil firing began and ended, duration of the emergency period, affected oil-fired equipment, and quantity of oil fired in each unit.

§117.105. Emission Specifications.

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

(d) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler, NO_x emissions in excess of the heat input weighted average of the applicable emission limits specified in subsections (a)-(c) of this section on a rolling 24-hour averaging period while firing a mixture of natural gas and fuel oil, as follows: 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)-(i) (No change.)

(j) No person shall allow the discharge into the atmosphere from any utility boiler, steam generator, or auxiliary steam boiler subject to this undesignated head (relating to Utility Electric Generation), carbon monoxide (CO) emissions in excess of 400 ppmv based on a rolling 24-hour averaging period.

(k) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to 10 MW, CO emissions in excess of a block one-hour average of 132 ppmv at 15% O_2, dry basis.

(l) No person shall allow the discharge into the atmosphere from any unit subject to this undesignated head, ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(m) The NO_x emission limits specified in subsections (a)-(i) of this section shall apply at all times, except as specified in §117.103 of this title (relating to Exemptions) and §117.107 of this title (relating to Alternative System-Wide Emission Specifications). The emission limits specified in subsections (j), (k), and (l) of this section shall apply at all times, except as specified in §117.103 of this title.

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

(1) The lower of any permit NO_x emission limit in effect on June 9, 1993 under a permit issued pursuant to Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) and the NO_x emission limits of subsections (a)-(i) of this section shall apply, except that gas-fired boilers operating under a permit issued after March 3, 1982, with an emission limit of 0.12 pound NO_x per million Btu heat input, shall be limited to that rate for the purposes of this subchapter.

(2) For any unit placed into service after June 9, 1993 and prior to May 31, 1995 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 and limited to the cumulative maximum rated capacity of the units replaced, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 pursuant to Chapter 116 of this title and the emission limits of subsections (a)-(i) 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

§117.107. Alternative System-Wide Emission Specifications.

(a) An owner or operator of any gaseous- or coal-fired utility boiler or stationary gas turbine m achieve compliance with the nitrogen o les (NO_x) emission limits of §117.105 c his title (relating to Emission Specificati) by achieving compliance with a system ide emission limitation, except as prov d for in subsection (d) of this section. A owner or operator who elects to com with system-wide emission limits shall educe emissions of NO_x from affected u s so that, if all such units were operated a heir maximum rated capacity, the system vide emission rate from all units in th system would not exceed the system : emission limit as defined in §117.10 his title (relating to Definitions), and sha stablish enforceable emission limits for ea affected unit in the system. A pound p million (MM) Btu emission limit based n a rolling 24-hour averaging period an pound per MMBtu emission limit based on a rolling 30-day averaging period sha l apply to each gas-fired unit in the tem A pound per MMBtu emission li based on a rolling 24-hour averaging od shall apply to each coal-fired unit the system. For stationary gas turbines the emission limits shall be assigned in units given by the appropriate emission itation of §117.105 of this title.

(b) An owne or operator of any fuel oil-fired utility oiler may achieve compliance with the NO_x emission limits of §117.105 of this titl y achieving compliance with a system de emission limitation. Any owner or rator who elects to comply with system ide emission limits for oil firing shall red e emissions of NO_x from affected units s hat, if all such units were operated at the verage activity level for fuel oil firing as fined in §117.10 of this title, the syste wide emission rate from all oil-fired un in the system would not exceed the syste wide emission limit as defined in §117.10 this title, and shall establish enforceable ission limits for oil firing for each affec unit in the system. A pound per MMB mission limit based on a rolling 24-hour eraging period shall apply to each oil-fir unit in the system. The emission limit signed to each oil-fired unit in the sys shall not exceed 0.5 pound NO_x per MM based on a rolling 24-hour average

(c) An owne or operator of any gaseous and liquid fi -fired utility boiler, steam generator, or turbine shall calculate the gaseous liquid fuel-fired system-wide emissi mits of subsections (a) and (b) of this ion separately. The owner or operator s ll also:

(1) (No c nge)

(2) compl with the assigned maximum allowable ission rates for liquid fuel while firing quid fuel only; and

(3) comp with a limit calculated as the actual h input weighted sum of the assigned gas-firing allowable emission limit and the assigned liquid-firing allowable emission limit while operating on liquid and gaseous fuel concurrently.

(d) Peaking gas turbines subject to the emission limits of §117.105(h) or (i) of this title and auxiliary steam boilers subject to the emission limits of §117.105(a), (c), (d), or (e) of this title shall comply with those individual emission specifications under this section and shall not be included in the system-wide emission specification. Coal-fired utility boilers or steam generators shall be treated as a separate system, and system averaging for coal-fired utility boilers or steam generators shall be limited to those units under this section.

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

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

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

In-stack NO_x = NO_x (allowable) x (1 - $\%H_2O/100$) x [20.9 - $\%O_2$/(1 - $\%H_2O/100$)]/5.9

NO_x (allowable) = the applicable NO_x emission specification of §117.105(f) or (g) of this title (expressed in ppmv NO_x at 15% oxygen, dry basis)

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

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

§117.109. Initial Control Plan Procedures.

(a) The owner or operator of any major source of nitrogen oxides (NO_x) shall submit, for the approval of the Executive Director, an initial control plan for installation of nitrogen oxides (NO_x) emissions control equipment and demonstration of anticipated compliance with other applicable requirements of this subchapter. The Executive Director shall approve the plan if it contains all the information specified in this section. Revisions to the initial control plan shall be submitted with the final control plan.

(b) The initial control plan shall be submitted in accordance with the schedule specified in §117.510(1) of this title (relating to Compliance Schedule For Utility Electric Generation) and shall contain the following:

(1) a list of all combustion units at the source with a maximum rated capacity greater than 5.0 million British thermal units (Btu) per hour; all stationary, reciprocating internal combustion which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater; all stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1.0 MW; to include the maximum rated capacity, anticipated annual heat input capacity factor, the facility identification numbers and emission point numbers as submitted to the Emissions Inventory Section of the Texas Natural Resource Conservation Commission (TNRCC), and the emission point numbers as listed on the Maximum Allowable Emissions Rate Table of any applicable TNRCC permit for each unit;

(2) identification of all units subject to the emission specifications of §117.105 or §117.107 of this title (relating to Emission Specifications and Alternative System-Wide Emission Specifications);

(3) identification of all boilers and stationary gas turbines with a claimed exemption from the emission specifications of §117.105 or §117.107 of this title and the rule basis for the claimed exemption;

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

(6) a list of any units which have been or will be retired, decommissioned, or shutdown and rendered inoperable, indicating the date of occurrence and whether these actions are a result of compliance with this regulation;

(7) the basis for calculation of the mass rate of NO_x emissions for each unit to demonstrate that each unit will achieve the NO_x emission rates specified in §117.105 or §117. 107 of this title. Emissions from stationary gas turbines shall be represented in the units given by the appropriate emission limitation of §117.105 of this title; and

(8) for units required to install totalizing fuel flow meters in accordance with §117.113(e), (g), or (h) of this title (relating to Continuous Demonstration of Compliance), indication of whether the devices have been placed in operation by April 1, 1994.

§117.111. Initial Demonstration of Compliance.

(a) All units which are subject to the emission limitations of §117.105 of this title (relating to Emission Specifications) or §117.107 of this title (relating to Alternative System-Wide Emission Specifications) shall be tested for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions. Units which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions. Such tests shall be performed in accordance with the schedules specified in §117. 510(4) and (5) of this title (relating to Compliance Schedule For Utility Electric Generation).

(b) (No change.)

(c) Continuous emissions monitoring systems (CEMS) required by §117.113(a) of this title (relating to Continuous Demonstration of Compliance) or predictive emissions monitoring systems (PEMS) required by §117.113(e) of this title shall be installed and operational prior to conducting initial demonstration of compliance testing under subsection (a) of this section. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(d) Initial compliance with the emission specifications of §117.105 or §117.107 of this title for units operating with CEMS in accordance with §117.113(a) of this title or with PEMS in accordance with §117.113(e) of this title shall be demonstrated using the NO_x CEMS or PEMS as follows:

(1) (No change.)

(2) To comply with the NO_x emission limit in pound per MMBtu on a rolling 24-hour average, NO_x emissions from a unit are monitored for 24 consecutive operating hours and the 24-hour average emission rate is used to determine compliance with the NO_x emission limit. The 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period. Compliance with the NO_x emission limit for fuel oil firing shall be determined based on the first 24 consecutive operating hours a unit fires fuel oil.

(3) To comply with the NO_x emission limit in pounds per hour or parts per million by volume at 15% oxygen, dry basis, on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable, after CEMS certification testing required in §117.113(b) of this title or PEMS certification testing required in §117.213(c) of this title (relating to Continuous Demonstration of Compliance) is used to determine compliance with the NO_x emission limit.

(4) To comply with the CO emission limit in parts per million by volume on a rolling 24-hour average, CO emissions from a unit are monitored for 24 consecutive hours and the rolling 24-hour average emission rate is used to determine compliance with the CO emission limit. The rolling 24-hour average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 24-hour test period.

§117.113. Continuous Demonstration of Compliance.

(a) The owner or operator of each affected unit, as defined in §117.101 of this title (relating to Applicability), except for exempted units listed in §117. 103 of this title (relating to Exemptions); peaking units as defined in §1.1 or §1.2 of Appendix E of 40 Code of Federal Regulations (CFR) Part 75, subject to the monitoring requirements of Appendix E; gas turbines monitored in accordance with subsection (f) of this section; and auxiliary boilers as defined in §117.10 of this title (relating to Definitions), monitored in accordance with subsection (d) of this section, shall install, calibrate, maintain, and operate an in-stack continuous emissions monitoring system (CEMS) to measure nitrogen oxides (NO_x) on an individual basis. The CEMS shall be installed and operating by the time of compliance with the emission limits specified in §117.105 of this title (relating to Emission Specifications) or §117.107 of this title (relating to Alternative System-Wide Emission Specifications). Each CEMS shall be able to use measured exhaust or fuel flow rate data obtained by a certified flow meter and be capable of measuring the following:

(1) NO_x;

(2) carbon monoxide (CO); and

(3) oxygen (O_2) or carbon dioxide (CO_2) as a diluent.

(b) Any CEMS required by subsection (a) of this section shall be installed, calibrated, maintained, and operated in accordance with 40 CFR, Part 75 or 40 CFR, Part 60, as applicable. The Executive Director of the Texas Natural Resource Conservation Commission (TNRCC) may approve alternative locations to in-stack monitoring for any affected unit subject to this section.

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

(e) As an alternative to CEMS, the owner or operator of units subject to continuous monitoring requirements under this undesignated head (relating to Utility Electric Generation) may, with the approval of the Executive Director, elect to install, calibrate, maintain, and operate predictive emissions monitoring systems (PEMS) and totalizing fuel flow meters. The required PEMS and fuel flow meters shall be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel flow for each affected unit and shall be used to demonstrate continuous compliance with the emission limitations of §117.105 or §117.107 of this title. As an alternative to using PEMS to monitor O_2 (or CO_2), subsection (a) of this section or similar alternative method approved by the Executive Director and the United States Environmental Protection Agency may be used Any PEMS for units subject to the requirements of 40 CFR 75 shall meet the requirements of §117.119 of this title (relating to Notification, Recordkeeping, and Reporting Requirements) and 40 CFR 75 Subpart E, §§75.40-75.48. Any PEMS for units not subject to the requirements of 40 CFR 75 shall meet the requirements of §117.119 of this title and either 40 CFR 75, Subpart E, §§75 40-75.48 or §117 213(c)(1)-(3) of this title.

(f) The owner or operator of each gas turbine subject to the emission specifications of §117.105 of this title, in lieu of monitoring emissions in accordance with the monitoring requirements of 40 CFR 75, may elect to comply with the following monitoring requirements:

(1) for gas turbines rated less than 30 megawatt (MW) or peaking gas turbines (as defined in §117.10 of this title) which use steam or water injection to comply with the emission specifications of §117. 105(h) or (i) of this title·

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

(B) (No change.)

(2) for gas turbines subject to the emission specifications of §117.105(f) or (g) of this title, install, calibrate, maintain and operate a CEMS or PEMS in compliance with subsection (b) of this section

(g) The owner or operator of any stationary gas turbine with a MW rating greater than or equal to 1.0 MW operated more than 850 hours per year shall install and maintain totalizing fuel flow meters on an individual unit basis.

(h) The owner or operator of any utility boiler, steam generator, or auxiliary steam boiler using the exemption of §117 103(b)(2) of this title (relating to Exemptions) shall install and maintain totalizing fuel meters for each individual unit, as approved by the Executive Director, and record the annual fuel input for each unit, based on a rolling monthly average. The owner or operator of any stationary gas turbine using the exemption of §117.103(b)(3) of this title shall record the operating time with an elapsed run time meter approved by the Executive Director

(i) The owner or operator of any utility boiler, steam generator, or auxiliary steam boiler using the exemption of §117.103(b)(2) of this title, or any stationary gas turbine using the exemption of §117.103(b)(3) of this title, shall notify the Executive Director within seven days if the Btu/yr or hour-per-year (hr/yr) limit specified in §117 103(b)(2) or §117 103(b)(3) of this title, as appropriate, is exceeded If the Btu/yr or hr/yr limit, as appropriate, is exceeded, the exemption from the emission specifications of §117.105 of this title shall be permanently withdrawn. 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 Btu/yr or hr/yr limit, as appropriate Included with this compliance plan, the owner or operator shall submit a schedule of increments of progress for the installation of the required control equipment This schedule shall be subject to the review and approval of the Executive Director.

(j) After the initial demonstration of compliance required by §117 111 of this title (relating to Initial Demonstration of Compliance), compliance with either §117.105 or §117.107 of this title, as applicable, 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 TNRCC compliance method. If compliance with §117 105 of this title is selected, no unit subject to §117.105 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117 105 of this title. If compliance with §117.107 of this title is selected, no unit subject to §117 107 of this title shall be operated at an emission rate higher than that approved by the Executive Director pursuant to §117 115(b) (2) of this title (relating to Final Control Plan Procedures)

§117.119 Notification, Recordkeeping, and Reporting Requirements.

(a) For units subject to the exemptions allowed under §117.103(a) of this title (relating to Exemptions), 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 Texas Natural Resource Conservation Commission (TNRCC), United States Environmental Protection Agency (EPA), and any local air pollution control agency having jurisdiction upon request These records shall include, but are not limited to. type of fuel burned; quantity of each type fuel burned, gross and net energy production in megawatt hours (MW-hr); and the date, time, and duration of the event

(b) The owner or operator of a unit subject to the provisions of §117 105 of this title (relating to Emission Specifications) or §117 107 of this title (relating to Alternative System-Wide Emission Specifications) shall submit notification to the Executive Director as follows

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

(2) verbal notification of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring systems (PEMS) performance evaluation conducted under §117 113 of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(c) The owner or operator of an affected unit shall furnish the Executive Director and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.111 of this title or any CEMS or PEMS performance evaluation conducted under §117.113 of this title within 60 days after completion of such testing or evaluation. Such results shall be submitted in accordance with the appropriate compliance schedules specified in §117 510(3) and (4) of this title (relating to Compliance Schedule for Utility Electric Generation)

(d) The owner or operator of a unit required to install a CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system under §117.113 of this title shall report in writing to the Executive Director on a quarterly basis any exceedance of the applicable emission limitations in §117.105 or §117.107 of this title 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) 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. For gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.113(f)(1)(B) of this title, excess emissions are computed as each one-hour period during which the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial demonstration of compliance test required by §117.111 of this title.

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

(5) if the total duration of excess emissions for the reporting period is less than 1.0% of the total unit operating time for the reporting period and the CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system downtime for the reporting period is less than 5.0% of the total unit operating time for the reporting period, only a summary report form (as outlined in the latest edition of the 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 steam-to-fuel or water-to-fuel ratio monitoring system downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(e) For units subject to the provisions of §117.105 or §117.107 of this title, records of hours of operation and other operating records shall be made and maintained for a period of at least two years. Records shall be available for inspection by the TNRCC, EPA, or local air pollution control agencies having jurisdiction upon request. Operating records for each unit shall be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or monthly for units exempt from the emission specifications based on annual heat input, or hours of operation per calendar year, and shall include.

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

(5) CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system data, as applicable, pursuant to §117.113 of this title. The records shall include:

(A) (No change.)

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

(C) (No change.)

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

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on May 25, 1994

TRD-9441677 Mary Ruth Holder
Director, Legal Division
Texas Natural Resource Conservation Commission

Effective date: June 23, 1994

Proposal publication date: January 4, 1994

For further information, please call: (512) 239-0615

♦ ♦ ♦

Commercial, Institutional, and Industrial Sources

- **30 TAC §§117.203, 117.205, 117.207-117.209, 117.211, 117.213, 117.215, 117.217, 117.219, 117.221, 117.223**

The amendments and new sections are adopted under the Texas Health and Safety Code (Vernon 1992), the Texas Clean Air Act (TCAA), §382.017, which provides the TNRCC with the authority to adopt rules consistent with the policy and purposes of the TCAA.

§117.203. Exemptions.

(a) (No change.)

(b) Units exempted from the provisions of this undesignated head (relating to Commercial, Institutional, and Industrial Sources), except for §117.209(c)(1) of this title (relating to Initial Control Plan Procedures) and §117.213(d)(2) and (g) of this title (relating to Continuous Demonstration of Compliance), include the following:

(1) any new units placed into service after November 15, 1992, except for new units which were placed into service as functionally identical replacement for existing units subject to the provisions of this undesignated head 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)-(5) (No change.)

(6) stationary gas turbines and engines, which are

(A) used in research and testing, or used for purposes of performance verification and testing, or used solely to power other engines or gas turbines during start-ups, or operated exclusively for firefighting and/or flood control, or used in response to and during the existence of any officially declared disaster or state of emergency, or used directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals, or used as chemical processing gas turbines; or

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

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

§117.205. Emission Specifications.

(a) No person shall allow the discharge of air contaminants into the atmosphere to exceed the emission limits of this section, except as provided in §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117.223 of this title (relating to Source Cap).

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

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

(B) gas-fired boilers and process heaters which have had NO_x reduction projects permitted since November 15, 1990 and prior to June 9, 1993 that were solely for the purpose of making early NO_x reductions, shall be subject to the appropriate emission limit of subsection (b) of this section. The affected person shall document that the NO_x reduction project was solely for the purpose of obtaining early reductions, and include this documentation in the initial control plan required in §117.209 of this title (relating to Initial Control Plan Procedures).

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

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

(B) the NO_x emission limit is the limit calculated as the permit Maximum Allowable Emission Rate Table emission limit in pounds per hour, divided by the maximum heat input to the unit in million Btu per hour (MMBtu/hr), as represented in the permit application. In the event the maximum heat input to the unit is not explicitly stated in the permit application, the rate shall be calculated from Table 6 of the permit application, using the design maximum fuel flow rate and higher heating value of the fuel, or, if neither of the above are available, the unit's nameplate heat input.

(3) For any unit placed into service after June 9, 1993 and prior to May 31, 1995 or the final compliance date as approved under the provisions of §117 540 of this title (relating to Phased Reasonably Available Control Technology (RACT)), as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 pursuant to Chapter 116 of this title and the emission limits of subsections (b)-(d) of this section shall apply. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.207 or §117.223 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

(b) For boilers and process heaters which operate with continuous emission monitors in accordance with §117 213(b) of this title (relating to Continuous Demonstration of Compliance), or with predictive emissions monitors in accordance with §117 213(c) of this title, the emission limits shall apply as the mass of nitrogen oxides (NO_x) emitted per unit of energy input (pound NO_x per million (MM) Btu), on a rolling 30-day average period, or as the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average For boilers and process heaters which do not operate with continuous or predictive emission monitors, the emission limits shall apply as the mass of NO_x emitted per hour (pounds NO_x per hour), on a block one-hour average. The mass of NO_x emitted per hour shall be calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in pound NO_x per MMBtu. For each commercial, institutional, or industrial boiler and process heater with a maximum rated capacity greater than or equal to 100 0 MMBtu/hr of heat input, the applicable emission limit is as follows:

(1) gas-fired boilers, as follows:

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

(B) low heat release boilers with preheated air greater than or equal to 200 degrees Fahrenheit and less than 400 degrees Fahrenheit, 0.15 lb NO_x/MMBtu of heat input;

(C) low heat release boilers with preheated air greater than or equal to 400 degrees Fahrenheit, 0.20 lb NO_x/MMBtu of heat input;

(D) high heat release boilers with no preheated air or preheated air less than 250 degrees Fahrenheit, 0.20 lb NO_x/MMBtu of heat input,

(E) high heat release boilers with preheated air greater than or equal to 250 degrees Fahrenheit and less than 500 degrees Fahrenheit, 0.24 lb NO_x/MMBtu of heat input; or

(F) high heat release boilers with preheated air greater than or equal to 500 degrees Fahrenheit, 0 28 lb NO_x/MMBtu of heat input.

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

(A) based on air preheat temperature:

(i) process heaters with preheated air less than 200 degrees Fahrenheit, 0.10 lb NO_x/MMBtu of heat input,

(ii) process heaters with preheated air greater than or equal to 200 degrees Fahrenheit and less than 400 degrees Fahrenheit, 0.13 lb NO_x/MMBtu of heat input, or

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

(B) based on firebox temperature

(i) process heaters with a firebox temperature less than 1,400 degrees Fahrenheit, 0 10 lb NO_x/MMBtu of heat input;

(ii) process heaters with a firebox temperature greater than or equal to 1,400 degrees Fahrenheit and less than 1,800 degrees Fahrenheit, 0.125 lb NO_x/MMBtu of heat input; or

(iii) process heaters with a firebox temperature greater than or equal to 1,800 degrees Fahrenheit, 0.15 lb NO_x/MMBtu of heat input;

(3) liquid fuel-fired boilers and process heaters, 0 30 lb NO_x/MMBtu of heat input;

(4) wood fuel-fired boilers and process heaters, 0 30 lb NO_x/MMBtu of heat input;

(5) any unit operated with a combination of gaseous, liquid, or wood fuel, a variable emission limit calculated as the heat input weighted average of the applicable emission limits of this subsection,

(6) for any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, a multiplier of 1.25 times the appropriate emission limit in this subsection may be used for that eight-hour period. The total hydrogen volume in all gaseous fuel streams will be divided by the total gaseous fuel flow volume to determine the volume percent of hydrogen in the fuel supply.

(c) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a megawatt (MW) rating greater than or equal to 10.0 MW, emissions in excess of a block one-hour average concentration of 42 parts per million by volume (ppmv) NO_x and 132 ppmv carbon monoxide (CO) at 15% oxygen (O_2), dry basis.

(d) No person shall allow the discharge into the atmosphere from any gas-fired, rich-burn, stationary, reciprocating internal combustion engine, emissions in excess of a block one-hour average of 2.0 grams NO_x per horsepower hour (g NO_x/hp-hr) and 3 0 g CO/hp-hr for engines which are:

(1) rated 150 hp or greater and located in the Houston/Galveston ozone nonattainment area; or

(2) rated 300 hp or greater and located in the Beaumont/Port Arthur ozone nonattainment area.

(e) No person shall allow the discharge into the atmosphere from any boiler or process heater subject to NO_x emission specifications in subsection (a) or (b) of this section, CO emissions in excess of the following limitations, based on a block one-hour average.

(1) for gas or liquid fuel-fired boilers or process heaters, 400 ppmv at 3.0% O_2, dry basis; or

(2) for wood fuel-fired boilers or process heaters, 775 ppmv at 7.0% O_2, dry basis.

(f) No person shall allow the discharge into the atmosphere from any unit subject to a NO_x emission limit in this undesignated head (relating to Commercial, Institutional, and Industrial Sources), ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period

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

(1) any commercial, institutional, or industrial boiler or process heater with a maximum rated capacity less than 100 MMBtu/hr,

(2) any low annual capacity factor boiler, process heater, stationary gas turbine, or stationary internal combustion engine as defined in §117.10 of this title (relating to Definitions),

(3) boilers and industrial furnaces which are regulated as existing facilities by the United States Environmental Protection Agency at 40 Code of Federal Regulations Part 266, Subpart H;

(4)-(7) (No change.)

(h) The NO_x emission limits specified in subsections (a)-(d) of this section shall apply at all times except as specified in §117 203 of this title (relating to Exemptions), §117.207 of this title, and §117.223 of this title The CO emission limits specified in subsections (c), (d), and (e) of this section and the ammonia emission limits specified in subsection (f) of this section shall apply at all times, except as specified in §117 203 of this title.

§117 207 Alternative Plant-Wide Emission Specifications.

(a) An owner or operator may achieve compliance with the emission limits of §117 205 of this title (relating to Emission Specifications) by achieving equivalent nitrogen oxides (NO_x) emission reductions obtained by compliance with a plant-wide emission limitation. Any owner or operator who elects to comply with a plant-wide emission limit shall reduce emissions of NO_x from affected units so that if all such units were operated at their maximum rated capacity, the plant-wide emission rate of NO_x from these units would not exceed the plant-wide emission limit as defined in §117 10 of this title (relating to Definitions) and shall establish an enforceable emission limit for each affected unit at the source For boilers and process heaters which operate with continuous emission monitors in accordance with §117.213(b) of this title (relating to Continuous Demonstration of Compliance), or with predictive emission monitors in accordance with §117 213(c) of this title, the emission limits shall apply as the mass of NO_x emitted per unit of energy input (pound NO_x per million (MM) Btu), on a rolling 30-day average period, or as the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average. For boilers and process heaters which do not operate with continuous or predictive emission monitors, the emission limits shall apply as the mass of NO_x emitted per hour (pounds NO_x per hour), on a block one-hour average. For stationary gas turbines, the emission limits shall apply as the concentration in parts per million by volume at 15% oxygen, dry basis on a block one-hour average. For stationary internal combustion engines, the emission limits shall apply in units of grams per horsepower-hour on a block one-hour average

(b) Units exempted from emission specifications in accordance with §117 205(g) of this title are also exempt under this section and shall not be included in the plant-wide emission limit, except as provided in subsection (f) of this section

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

(f) The owner or operator of exempted units as defined in §117.205(g) of this title may elect to include one or more of an entire equipment class of exempted units into the alternative plant-wide emission specifications as defined in this section. The equipment classes which may be included in the alternative plant-wide emission specifications as an entire population of units at the major source include the following: fluid catalytic cracking unit carbon monoxide (CO) boilers; lean-burn, gas-fired, stationary, reciprocating internal combustion engines rated 150 horsepower (hp) or greater; boilers, steam generators, or process heaters with a maximum rated capacity of greater than or equal to 40 million Btu per hour (MMBtu/hr) and less than 100 MMBtu/hr, stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1 0 MW and less than 10.0 MW, and boilers and industrial furnaces which are regulated as existing facilities by the United States Environmental Protection Agency (EPA) at 40 Code of Federal Regulations (CFR) Part 266, Subpart H Low annual capacity factor boilers, process heaters, gas turbines, or engines as defined in §117 10 of this title are not to be considered as part of that class of equipment. The individual emission limits that are to be used in calculating the alternative plant-wide emission specifications are the lower of the emission specifications determined in accordance with §117 205(a) of this title and the following, as applicable:

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

(5) boilers and industrial furnaces which are regulated as existing facilities by the EPA at 40 CFR Part 266, Subpart H, the appropriate emission limitation in §117.205(b) of this title.

(g) Solely for the purposes of calculating the plant-wide emission limit, the allowable mass emission rate for each affected unit shall be calculated from the emission specifications of §117.205 of this title, as follows

(1)-(2) (No change)

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

In-stack NO_x = NO_x (allowable) x (1 - $\%H_2O/100$) x [20 9 - $\%O_2/(1 - \%H_2O/100)$]/5 9

NO_x (allowable) = the applicable NO_x emission specification of §117 205(c) of this title (expressed in ppmv NO_x at 15% O_2, dry basis).

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

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

(4) The NO_x emission rate (in pounds per hour) for each affected gas-fired boiler and process heater firing gaseous fuel which contains more than 50% hydrogen (H_2) by volume, over an annual basis, in which the fuel gas composition is sampled and analyzed every three hours, may use a multiplier of 1 25 times the product of its maximum rated capacity and its NO_x emission specification of §117.205 of this title Double application of the H_2 content multiplier using this paragraph and §117.205(b)(6) of this title is not allowed.

(h) The owner or operator of any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% H_2 by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, may use a multiplier of 1.25 times the emission limit assigned to the unit in this section for that eight-hour period, not applicable to units under subsection (g)(4) of this section. The total H_2 volume in all gaseous fuel streams will be divided by the total gaseous fuel flow volume to determine the volume percent of H_2 in the fuel supply

§117.209. Initial Control Plan Procedures.

(a) The owner or operator of any major source of nitrogen oxides (NO_x) shall submit, for the approval of the Executive Director, an initial control plan for installation of NO_x emissions control equipment (if required in order to comply with the emission specifications of this subchapter) and demonstration of anticipated compliance with the applicable requirements of this subchapter. The Executive Director shall approve the plan if it contains all the information specified in this section. Revisions to the initial control plan shall be submitted with the final control plan.

(b) The owner or operator shall provide results of emissions testing using portable or reference method analyzers or, as available, initial demonstration of compliance testing conducted in accordance with §117.211(e) or (f) of this title (relating to Initial Demonstration of Compliance) for NO_x, carbon monoxide (CO), and oxygen emissions while firing gaseous fuel (and as applicable, hydrogen (H_2) fuel for units which may fire more than 50% H_2 by volume) and liquid and/or solid fuel at the maximum rated capacity or as near thereto as practicable, for the units listed in this subsection. Previous testing documentation for any claimed test waiver as allowed by §117.211(d) of this title shall be submitted with the initial control plan. Any units which were not operated between June 9, 1993 and April 1, 1994 and do not have earlier representative emission test results available shall be tested and the results submitted to the TNRCC, with certification of the equipment's shutdown period, within 90 days after the date such equipment is returned to operation. Test results are required for the following units:

(1) boilers and process heaters with a maximum rated capacity greater than or equal to 40.0 million Btu per hour (MMBtu/hr), except for low annual capacity factor boilers and process heaters as defined in §117.10 of this title (relating to Definitions);

(2) boilers and industrial furnaces with a maximum rated capacity greater than or equal to 40.0 MMBtu/hr which are regulated as existing facilities by the United States Environmental Protection Agency (EPA) at 40 Code of Federal Regulations, Part 266, Subpart H, except for low annual capacity factor boilers and process heaters as defined in §117.10 of this title;

(3) fluid catalytic cracking units with a maximum rated capacity greater than or equal to 40 MMBtu/hr;

(4) gas turbine supplemental waste heat recovery units with a maximum rated fired capacity greater than or equal to 40 MMBtu/hr, except for low annual capacity factor gas turbine supplemental waste heat recovery units as defined in §117. 10 of this title;

(5) stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1.0 MW, except for low annual capacity factor gas turbines or peaking gas turbines as defined in §117.10 of this title; and

(6) gas-fired, stationary, reciprocating internal combustion engines which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater, except for low annual capacity factor engines or peaking engines as defined in §117 10 of this title.

(c) The initial control plan shall be submitted in accordance with the schedule specified in §117.520(1) of this title (relating to Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources) and shall contain the following:

(1) a list of all combustion units at the source with a maximum rated capacity greater than 5 0 million Btu per hour; all stationary, reciprocating internal combustion engines which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater; all stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1 0 MW, to include the maximum rated capacity, anticipated annual capacity factor, the facility identification numbers and emission point numbers as submitted to the Emissions Inventory Section of the Texas Natural Resource Conservation Commission (TNRCC), and the emission point numbers as listed on the Maximum Allowable Emissions Rate Table of any applicable TNRCC permit for each unit,

(2) identification of all units subject to the emission specifications of §117 205 of this title (relating to Emission Specifications), §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117 223 of this title (relating to Source Cap);

(3) identification of all boilers, process heaters, stationary gas turbines, or engines with a claimed exemption from the emission specifications of §117 205 or §117.207 of this title and the rule basis for the claimed exemption;

(4) identification of the election to use individual emission limits as specified in §117 205 of this title, the plant-wide emission limit as specified in §117 207 of this title, or the source cap emission limit as specified in §117.223 of this title to achieve compliance with this rule;

(5) (No change.)

(6) a list of units requiring operating modifications to comply with §117.208(d) of this title (relating to Operating Requirements) and the type of modification to be applied for all such units, including an anticipated construction schedule,

(7) a list of any units which have been or will be retired, decommissioned, or shutdown and rendered inoperable after November 15, 1990 as a result of compliance with this regulation, indicating the date of occurrence or anticipated date of occurrence;

(8) the basis for calculation of the rate of NO_x emissions for each unit to demonstrate that each unit will achieve the NO_x emission rates specified in §117 205, §117.207, or §117 223 of this title. For fluid catalytic cracking unit CO boilers, the basis for calculation of the pound NO_x per million Btu (lb NO_x/MMBtu) rate for each unit shall include the following.

(A)-(B) (No change)

(C) the calculation of the CO boiler lb NO_x/MMBtu emission rate,

(9) for units required to install totalizing fuel flow meters in accordance with §117.213(a)-(e) of this title (relating to Continuous Demonstration of Compliance), indication of whether the devices are currently in operation, and if so, whether they have been installed as a result of the requirements of this chapter;

(10) for units which have had NO_x reduction projects as specified in §117 205(a)(1)(B) of this title, documentation that such projects were undertaken solely for the purpose of obtaining early NO_x reductions; and

(11) test results in accordance with subsection (b) of this section

§117.211. Initial Demonstration of Compliance.

(a) All units which are subject to the emission limitations of §117.205 of this title (relating to Emission Specifications), §117 207 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117.223 of this title (relating to Source Cap), and all units belonging to equipment classes which are elected to be included in the alternative plant-wide emission specifications as defined in §117.207(f) of this title, or in the source cap as defined in §117 223(b)(4) of this title, shall be tested for nitrogen oxides (NO_x), carbon monoxide

(CO), and oxygen (O_2) emissions while firing gaseous fuel (and as applicable, hydrogen (H_2) fuel for units which may fire more than 50% H_2 by volume, and liquid and solid fuel). Units which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions Initial demonstration of compliance testing of these units shall be performed in accordance with the schedule specified in §117 520 of this title (relating to Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources)

(b) The initial demonstration of compliance tests required by subsection (a) of this section shall use the test methods referenced in subsection (e) or (f) of this section and shall be used for determination of initial compliance with either the emission limits of §117 205 of this title, the assigned emission limits of §117.207 of this title, or §117.223 of this title, as applicable Test results shall be reported in the units of the applicable emission limits and averaging periods.

(c) Any continuous emissions monitoring system (CEMS) required by §117.213(b) of this title (relating to Continuous Demonstration of Compliance) or any predictive emissions monitoring system (PEMS) approved for use in lieu of CEMS in accordance with §117.213(c) of this title shall be installed and operational prior to conducting initial demonstration of compliance testing under subsection (a) of this section Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system

(d) Testing conducted prior to the effective date of this rule may be used to demonstrate compliance with the standards specified in §117 205, §117 207, or §117 223 of this title, or to satisfy the testing requirements of §117.209(b) of this title (relating to Initial Control Plan Procedures), if the owner or operator of an affected facility demonstrates to the Executive Director that the prior demonstration of compliance testing at least meets the requirements of subsections (a), (b), (c), (e), and (f) of this section The Executive Director reserves the right to request demonstration of compliance testing or CEMS or PEMS performance evaluation at any time

(e) Compliance with the emission specifications of §117.205, §117.207, or §117.223 of this title for units operating without CEMS or PEMS shall be demonstrated while operating at the maximum rated capacity, or as near thereto as practicable. Compliance shall be determined by the average of three one-hour emission test runs, using the following test methods

(1) Test Method 7E or 20 (40 Code of Federal Regulations (CFR), Part 60, Appendix A) for NO_x,

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

(4) Test Method 2 (40 CFR 60, Appendix A) for exhaust gas flow and following the measurement site criteria of Test Method 1, Section 2 1 (40 CFR 60, Appendix A), or Test Method 19 (40 CFR 60, Appendix A) for exhaust gas flow in conjunction with the measurement site criteria of Performance Specification 2, Section 3.2 (40 CFR 60, Appendix B);

(5) American Society of Testing and Materials (ASTM) Method D1945-91 or ASTM Method D3588-93 for fuel composition; ASTM Method D1826-88 or ASTM Method D3588-91 for calorific value, or alternate methods as approved by the Executive Director and the EPA; or

(6) EPA approved alternate test methods or minor modifications to these test methods as approved by the Executive Director, as long as the minor modifications meet the following conditions.

(A) the change does not affect the stringency of the applicable emission limitation, and

(B) the change affects only a single source or facility application.

(f) Initial compliance with the emission specifications of §117.205 or §117 207 of this title for units operating with CEMS in accordance with 117.213(b) of this title, or PEMS in accordance with 117.213(c) of this title, shall be demonstrated using the CEMS or PEMS as follows

(1) For boilers and process heaters complying with a NO_x emission limit in pound per MMBtu on a rolling 30-day average, NO_x emissions from the unit are monitored for 30 successive unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission limit The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) For boilers, process heaters, and gas turbines complying with a NO_x emission limit in pounds per hour or parts per million by volume at 15% oxygen, dry basis, on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable, after CEMS certification testing required in §117 213(b) of this title or PEMS certification testing required in §117 213(c) of this title is used to determine compliance with the NO_x emission limit

(3) For units complying with a CO emission limit, block one-hour average, any one-hour period after CEMS certification testing required in §117.213(b) of this title or PEMS certification testing required in §117. 213(c) of this title is used to determine compliance with the CO emission limit.

§117.213. Continuous Demonstration of Compliance.

(a) The owner or operator of units listed in this subsection and subject to the provisions of this undesignated head (relating to Commercial, Institutional, and Industrial Sources) shall install, calibrate, maintain, and operate an oxygen (O_2) monitor to measure exhaust O_2 concentration and a totalizing fuel flow meter to measure the fuel usage (for natural gas, refinery or process fuel gas, and fuel oil streams). The O_2 monitors and totalizing fuel flow meters shall be installed and operating by the time of compliance with the emission limits specified in §117.205 of this title (relating to Emission Specifications) or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) for the following units:

(1) each commercial, institutional, and industrial boiler with a rated heat input greater than or equal to 100 million Btu per hour (MMBtu/hr) and less than 250 MMBtu/hr and an annual heat input greater than 2. $2(10^{11})$ Btu per year (Btu/yr); and

(2) each process heater with a rated heat input greater than or equal to 100 MMBtu/hr and less than 200 MMBtu/hr and an annual heat input greater than $2.2(10^{11})$ Btu/yr.

(b) The owner or operator of units listed in this subsection and subject to the provisions of this undesignated head shall install, calibrate, maintain, and operate a continuous exhaust nitrogen oxides (NO_x) monitor, a carbon monoxide (CO) monitor, an O_2 (or carbon dioxide (CO_2)) diluent monitor, and a totalizing fuel flow meter (for natural gas, refinery or process fuel gas, and fuel oil streams). The required continuous emissions monitoring systems (CEMS) and fuel flow meters will be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel flow for each affected unit. One CEMS may be used to monitor up to three units. Any CEMS shall meet all the requirements of 40 Code of Federal Regulations (CFR), Part 60, §60.13; 40 CFR 60, Appendix B, Performance Specification 2, 3, and 4, and quality assurance procedures of 40 CFR 60, Appendix F, except that a cylinder gas audit may be performed in lieu of the annual relative accuracy test audit required in Section 5.1.1. The CEMS shall be subject to the approval of the Executive Director of the Texas Natural Resource

Conservation Commission (TNRCC) under any permit issued pursuant to Title V of the 1990 Federal Clean Air Act Amendments.

(1) The CEMS shall be installed by the time of compliance with the emission limits specified in §117.205 or §117.207 of this title for the following units:

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

(C) each stationary gas turbine with a megawatt (MW) rating greater than or equal to 30 MW operated more than 850 hours per year;

(D) (No change.)

(E) each unit for which the owner or operator elects to comply with the NO_x emission specifications of §117.205 or §117.207 of this title using a pound per MMBtu limit on a 30-day rolling average.

(2) The units listed in §117.205(g)(3)-(5) of this title are not required to install CEMS under this subsection.

(3) Gas turbines or other units which are affected units and are subject to continuous emissions monitoring requirements in accordance with 40 CFR 75 shall comply with those requirements in lieu of complying with the 40 CFR 60 requirements of this section.

(c) As an alternative to CEMS, the owner or operator of units subject to continuous monitoring requirements under this undesignated head may, with the approval of the Executive Director, elect to install, calibrate, maintain, and operate predictive emissions monitoring systems (PEMS) and totalizing fuel flow meters (for natural gas, refinery or process fuel gas, and fuel oil streams). The required PEMS and fuel flow meters may be used to predict any or all of the variables of NO_x, CO, and O_2 (or CO_2) emissions and fuel flow for each affected unit and shall be used to demonstrate continuous compliance with the emission limitations of §117.205 and §117.207 of this title or §117.223 of this title (relating to Source Cap) as applicable. CEMS shall be used to monitor any of the variables of NO_x, CO, and O_2 (or CO_2) not monitored with PEMS. As an alternative to using PEMS to monitor O_2 (or CO_2), subsection (b) of this section or similar alternative method approved by the Executive Director and the United States Environmental Protection Agency (EPA) may be used. Any PEMS shall meet the requirements of §117.219 of this title (relating to Notification, Recordkeeping, and Reporting Requirements) and all the requirements of 40 CFR 75, Subpart E, except that the following alternatives or exceptions may be made:

(1) alternatives to 40 CFR 75, Subpart E which the owner or operator demonstrates to the satisfaction of the TNRCC and the EPA to be substantially equivalent to the requirements of 40 CFR 75, Subpart E;

(2) requirements of 40 CFR 75, Subpart E which the owner or operator demonstrates to the satisfaction of the TNRCC are not applicable; and

(3) as an alternative to the test procedure of Subpart E for initial certification of any unit while firing its primary fuel, the owner or operator:

(A) may perform the following initial certification tests:

(i) conduct initial relative accuracy test audit (RATA) pursuant to 40 CFR Part 60, Appendix B, Performance Specification 2, subsection 4.3 (pertaining to NO_x); Performance Specification 3, subsection 2.3 (pertaining to O_2 or CO_2); and Performance Specification 4, and subsection 2.3 (pertaining to CO) at low, medium, and high levels of the key operating parameter affecting NO_x; and

(ii) conduct an F-test, a t-test, and a correlation analysis pursuant to 40 CFR 75, Subpart E at low, medium, and high levels of the key operating parameter affecting NO_x. Calculations shall be based on a minimum of 30 successive emission data points at each tested level which are either 15-minute averages, 20-minute averages, or hourly averages. The F-test shall separately be performed at each tested level while the t-test and the correlation analysis shall be performed using all data collected at the three tested levels; and

(B) shall further demonstrate PEMS accuracy with the following tests:

(i) for each of the three successive quarters following the quarter in which initial certification was conducted, demonstrate accuracy and precision of PEMS for at least one unit of a category of equipment by performing RATA and statistical testing in accordance with paragraph (A) of this paragraph; and

(ii) for each unit and semiannually thereafter, conduct RATA pursuant to 40 CFR 60, Appendix B, Performance Specification 2, subsection 4.3 (pertaining to NO_x); Performance Specification 3, subsection 2.3 (pertaining to O_2 or CO_2) ; and Performance Specification 4, subsection 2.3 (pertaining to CO) at normal load operations. RATA may be performed on an annual basis rather than on a semiannual basis if the relative accuracy during the previous audit for the NO_x, CO, and O_2 (or CO_2) monitors is less than or equal to 7.5%; and

(iii) for each alternative fuel fired in a unit, the PEMS shall be certified in accordance with subparagraph (A) of this paragraph unless the alternative fuel effects on NO_x, CO, and O_2 (or CO_2) emissions were addressed in the model training process.

(d) In addition to the totalizing fuel flow meters specified in subsections (a), (b), and (c) of this section, the owner or operator shall install and maintain totalizing fuel flow meters (for natural gas, refinery or process fuel gas, and fuel oil streams) on an individual unit basis on the following units:

(1) process heaters and commercial, institutional, and industrial boilers, including boilers and industrial furnaces regulated as existing facilities by the EPA at 40 CFR Part 266, Subpart H, and gas turbine supplemental waste heat recovery units, with a rated heat input greater than or equal to 40.0 MMBtu/hr and less than 100.0 MMBtu/hr;

(2) (No change.)

(3) lean-burn, stationary, reciprocating internal combustion engines which are located in the Houston/Galveston ozone nonattainment area and rated 150 horsepower (hp) or greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater, operated 850 or more hours per year;

(4) stationary gas turbines with a MW rating greater than or equal to 1.0 MW and less than 30.0 MW operated more than 850 hours per year; and

(5) supplemental fuel fed to fluid catalytic cracking unit boilers.

(e) The owner or operator of any stationary gas engine subject to the emission specifications of §117.205 or §117.207 of this title shall install and maintain a totalizing fuel flow meter and perform biennial stack testing of engine emissions of NO_x and CO, measured in accordance with the methods specified in §117.211(e) of this title (relating to Initial Demonstration of Compliance). In lieu of performing stack sampling on a biennial calendar basis, an owner or operator may elect to install and operate an elapsed operating time meter and shall test the engine within 15,000 hours of engine operation after the previous emission test. The owner or operator who elects to test on an operating hour schedule shall submit, in writing, to the TNRCC and any local air pollution agency having jurisdiction, biennially after the initial demonstration of compliance, documentation of the actual recorded hours of engine operation since the previous emission test, and an estimate of the date of the next required sampling.

(f) 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 shall either:

(1) install, calibrate, maintain, and operate a CEMS in compliance with subsection (b) of this section or a PEMS in compliance with subsection (c) of this section; or

(2) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption. 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 applicable emission specification of §117.205 or §117.207 of this title. Steam or water injection control algorithms are subject to Executive Director approval.

(g) The owner or operator of any low annual capacity factor stationary gas turbine or stationary internal combustion engine as defined in §117.10 of this title shall record the operating time with an elapsed run time meter.

(h) The owner or operator of any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% hydrogen (H_2) by volume, shall sample, analyze, and record every three hours the fuel gas composition to comply with the emission specifications of §117.205 or §117.207 of this title. The total H_2 volume flow in all gaseous fuel streams to the unit will be divided by the total gaseous volume flow to determine the volume percent of H_2 in the fuel supply to the unit. Fuel gas analysis shall be tested according to American Society of Testing and Materials (ASTM) Method D1945-81 or ASTM Method D2650-83, or other methods which are demonstrated to the satisfaction of the Executive Director and the EPA to be equivalent. A gaseous fuel stream containing 99% H_2 by volume or greater may use the following procedure to be exempted from the sampling and analysis requirements of this subsection.

(1) A fuel gas analysis shall be performed initially using one of the test methods in this subsection to demonstrate that the gaseous fuel stream is 99% H_2 by volume or greater.

(2) The process flow diagram of the process unit which is the source of the H_2 shall be supplied to the TNRCC to illustrate the source and supply of the hydrogen stream.

(3) (No change.)

(i) After the ...itial demonstration of compliance require... by §117. 211 of this title, compliance w... either §117.205 or §117.207 of this titl... as applicable, shall be determined by the ... thods required in this section. For enforce... ent purposes, the Executive Director may also use other TNRCC compliance methods to determine whether the source is in com... iance with applicable emission limitations.

(j) If compl... nce with §117.205 of this title is selecte... , no unit subject to §117.205 of this title shall be operated at an emission rate highe... than that allowed by the emission specifi... tions of §117.205 of this title. If compli... ce with §117.207 of this title is selecte... no unit subject to §117.207 of this title shall be operated at an emission rate higher than that approved by the Executive D... ector pursuant to §117.215(b)(4) of th... title (relating to Final Control Plan Proce... es).

(k) The ow... or operator of any low annual capacity factor boiler, process heater, stationary ga... turbine, or stationary internal combustion ... ngine, as defined in §117.10 of this title, shall notify the Executive Director within ... ven days if the Btu/yr or hour-per-year (l... r) limit specified in §117.10 of this title ... is appropriate, is exceeded. If the Btu/y... or hr/yr limit, as appropriate, is exceede... , the exemption from the emission speci... ions of §117.205 of this title shall be p... manently withdrawn. Within 90 days afte... loss of the exemption, the owner or operat... r shall submit a compliance plan detaili... a plan to meet the applicable complian... limit as soon as possible, but no later ... an 24 months after exceeding the Btu/... or hr/yr limit, as appropriate. Included ... with this compliance plan, the owner or ... erator shall submit a schedule of increm... s of progress for the installation of the ... quired control equipment. This schedule shall be subject to the review and approva... the Executive Director.

§117.215. Final C... rol Plan Procedures.

(a) For sources complying with §117.205 of this title (relating to Emission Specifications), the owner or operator of an affected source shall submit a final control report to show comp... ance with the requirements of §117.205 ... this title by the date specified in §117.5...) of this title (relating to Compliance ... hedule For Commercial, Institution... and Industrial Combustion Source... The report shall include a list of all aff... ted units showing the method of control o... nitrogen oxides (NO_x) emissions for each unit and the results of testing required in §117.211 of this title (relating to Initial ... monstration of Compliance).

(b) For so... es complying with §117. 207 of this ti... (relating to Alternative Plant-Wide Emission Specifications), the owner or operator of an affected source shall submit a final control plan to show attainment of the requirements of §117.207 of this title by the date specified in §117 520(6) of this title. The owner or operator shall:

(1) assign to each affected boiler or process heater the maximum allowable NO_x emission rate in pound per million Btu (rolling 30-day average), or in pounds per hour (block one-hour average) while firing gaseous or liquid fuel, which are allowable for that unit under the requirements of §117.207 of this title;

(2) assign to each affected stationary gas turbine the maximum allowable NO_x emission in parts per million by volume at 15% oxygen, dry basis on a block one-hour average;

(3) assign to each affected stationary internal combustion engine the maximum allowable NO_x emission rate in grams per horsepower-hour on a block one-hour average,

(4) submit a list to the Executive Director for approval of the maximum allowable NO_x emission rates identified in paragraphs (1)-(3) of this subsection and maintain a copy of the approved list for verification of continued compliance with the requirements of §117. 207 of this title; and

(5) submit a description of the NO_x control method used to achieve compliance with §117.207 of this title, and the results of testing for each unit in accordance with the requirements of §117.211 of this title. For boilers and process heaters complying with a pound per million Btu emission limit on a rolling 30-day average, this information may be submitted according to the schedule given in §117.520(4) of this title;

(6) submit a list summarizing the results of testing of each unit at maximum rated capacity, in accordance with the requirements of §117.211(e), (f)(2), and (f)(3) of this title.

(c) For sources complying with §117.223 of this title (relating to Source Cap), the owner or operator of an affected source shall submit a final control plan to show attainment of the requirements of §117.223 of this title by the date specified in §117.520(6) of this title.

§117 219. Notification, Recordkeeping, and Reporting Requirements.

(a) For units subject to the exemptions allowed under §117 203(a) of this title (relating to Exemptions), 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 Texas Natural Resource Conservation Commission (TNRCC), United States Environmental Protection Agency (EPA), and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type fuel burned; and the date, time, and duration of the event.

(b) The owner or operator of an affected source shall submit notification to the Executive Director, as follows:

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

(2) verbal notification of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) performance evaluation conducted under §117.213 of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(c) The owner or operator of an affected unit shall furnish the Executive Director and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.211 of this title or any CEMS or PEMS performance evaluation conducted under §117.213 of this title, within 60 days after completion of such testing or evaluation. Such results shall be submitted in accordance with the compliance schedule specified in §117.520 of this title (relating to Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources).

(d) 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 quarterly basis any exceedance of the applicable emission limitations in §117.205 of this title (relating to Emission Specifications) or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications) and the monitoring system performance. All reports shall be post-marked or received by the 30th day following the end of each calendar quarter. 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. For gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.213(f)(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.

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

(5) if the total duration of excess emissions for the reporting period is less than 1.0% of the total unit operating time for the reporting period and the CEMS, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system downtime for the reporting period is less than 5.0% of the total unit operating time for the reporting period, only a summary report form (as outlined in the latest edition of the 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, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(e) The owner or operator of any rich-burn engine subject to the emission limitations in §117. 205 or §117.207 of this title shall report in writing to the Executive Director on a quarterly basis any excess emissions and the air-fuel ratio monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar quarter. 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(e) of this title, computed in pounds per hour and grams per horsepower hour, any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the engine operating time during the reporting period;

(2) (No change.)

(f) The owner or operator of an affected unit shall maintain written records of all continuous emissions monitoring and demonstration of compliance test results, hours of operation, and fuel usage rates. Such records shall be kept for a period of at least two years and shall be made available upon request by authorized representatives of the TNRCC, EPA, or local air pollution control agencies having jurisdiction. The emission monitoring (as applicable) and fuel usage records for each unit shall be recorded and maintained:

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

§117.223. Source Cap.

(a) An owner or operator may achieve compliance with the emission limits of §117.205 of this title (relating to Emission Specifications) by achieving equivalent nitrogen oxides (NO_x) emission reductions obtained by compliance with a source cap emission limitation in accordance with the requirements of this section. Each equipment category at a source whose individual emission units would otherwise be subject to the NO_x emission limits of §117.205 of this title may be included in the source cap. Any equipment category included in the source cap shall include all emission units belonging to that category. Equipment categories include, but are not limited to, the following: steam generation, electrical generation, and units with the same product outputs, such as ethylene cracking furnaces. All emission units not included in the source cap shall comply with the requirements of §117.205 or §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications).

(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:

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

Where: i = each emission unit in the emission cap

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

H_i = The actual historical average of the daily heat input for each unit included in the source cap, in million British thermal units (MMBtu) per day, as certified to the Texas Natural Resource Conservation Commission

(TNRCC), 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.

R_i = (A) 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.

(B) 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 (BACT) limit for any unit subject to a permit issued pursuant to Chapter 116 of this title, in lb NO_x/MMBtu, that applies to emission unit *i* in the absence of trading.

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

$$\text{NO}_x \text{ maximum daily cap (lb/day)} = \sum_{i=1}^{N} (H_{Mi} \times R_i)$$

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

H_{Mi} = The maximum daily heat input, as certified to the TNRCC, allowed or possible (whichever is lower) in a 24-hour period.

(3) Each emission unit included in the source cap shall be subject to the requirements of both paragraphs (1) and (2) of this subsection at all times.

(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. Such units shall be required to reduce emissions available for use in the cap by an additional amount calculated in accordance with the 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) For stationary internal combustion engines, the source cap allowable emission rate shall be calculated in pounds per hour using the procedures specified in §117 207(g)(2) of this title

(6) For stationary gas turbines, the source cap allowable emission rate shall be calculated in pounds per hour using the procedures specified in §117.207(g) (3) of this title

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

(1) For each unit included in the source cap, either.

(A) install, calibrate, maintain, and operate a continuous exhaust nitrogen oxides (NO_x) monitor, carbon monoxide (CO) monitor, an oxygen (O_2) (or carbon dioxide (CO_2)) diluent monitor, and a totalizing fuel flow meter in accordance with the requirements of §117 213(b) of this title (relating to Continuous Demonstration of Compliance) The required continuous emissions monitoring systems (CEMS) and fuel flow meters shall be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel use for each affected unit and shall be used to demonstrate continuous compliance with the source cap,

(B) install, calibrate, maintain, and operate a predictive emissions monitoring system (PEMS) and a totalizing fuel flow meter in accordance with the requirements of §117 213(c) of this title. The required PEMS and fuel flow meters shall be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel flow for each affected unit and shall be used to demonstrate continuous compliance with the source cap, or

(C) for units not subject to continuous monitoring requirements, as provided for in §117 213(a) of this title, and units belonging to the equipment classes listed in §117.207(f) of this title, the owner or operator may use the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117 211(e) of this title (relating to Initial Demonstration of Compliance) in lieu of CEMS or PEMS Emission rates for these units shall be limited to the maximum emission rates obtained from testing conducted under §117 211(e) of this title

(2) For each operating unit equipped with CEMS, the owner or operator shall either use a PEMS pursuant to §117 213(c) 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 CFR 75 46 shall be used to provide emissions substitution data for units equipped with PEMS

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

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

(f) The owner or operator shall demonstrate initial compliance with the source cap in accordance with the schedule specified in §117.520 of this title (relating to Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources).

(g) 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 unit shall have actually operated since November 15, 1990

(2) 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) The actual heat input shall be calculated according to subsection (b)(1) of this section If the unit was not in service 24 consecutive months between January 1, 1990 and June 9, 1993, the actual heat input shall be the average daily heat input for the continuous time period that the unit was in service, plus one standard deviation of the average daily heat input for that period. The maximum heat input shall be the maximum heat input, as certified to the TNRCC, allowed or possible (whichever is lower) in a 24-hour period.

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

(5) 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) A unit which has been shutdown and rendered inoperable after June 9, 1993, but not permanently retired, should be identified in the initial control plan and may be included in the source cap.

(i) An owner or operator who chooses to use the source cap option shall include in the initial control plan required to be filed under §117.209 of this title (relating to Initial Control Plan Procedures) a plan for initial compliance. The owner or operator shall include in the initial control plan the identification of the election to use the source cap procedure as specified in this section to achieve compliance with this section and shall specifically identify all sources that will be included in the source cap The owner or operator shall also include in the initial control plan the method of calculating the actual heat input for each unit included in the source cap, as specified in subsection (b)(1) of this section. An owner or operator who chooses to use the source cap option shall include in the final control plan procedures of §117 215 of this title (relating to Final Control Plan Procedures) the information necessary under this section to demonstrate final compliance with the source cap

(j) For the purposes of determining compliance with the source cap emission limit, the contribution of each affected unit that is operating during a startup, shutdown, or upset period shall be calculated from the NO_x emission rate, as measured by the initial demonstration of compliance, for that unit, unless the owner or operator provides data demonstrating to the satisfaction of the Executive Director that actual emissions were less than maximum emissions during such periods

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority

Issued in Austin, Texas, on May 25, 1994

TRD-9441678 Mary Ruth Holder
Director, Legal Division
Texas Natural Resource Conservation Commission

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For further information, please call (512) 239-0615

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Subchapter C. Acid Manufacturing

Adipic Acid Manufacturing

• 30 TAC §§117.311, 117.313, 117.319, 117.321

The amendments are adopted under the Texas Health and Safety Code (Vernon 1992), the Texas Clean Air Act (TCAA), §382 017, which provides the TNRCC with the authority to adopt rules consistent with the policy and purposes of the TCAA

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority

Issued in Austin, Texas, on May 25, 1994

TRD-9441679 Mary Ruth Holder
Director, Legal Division
Texas Natural Resource Conservation Commission

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Nitric Acid Manufacturing-Ozone Nonattainment Areas

• 30 TAC §§117.411, 117.413, 117.419, 117.421

The amendments are adopted under the Texas Health and Safety Code (Vernon 1992), the Texas Clean Air Act (TCAA), §382 017, which provides the TNRCC with the authority to adopt rules consistent with the policy and purposes of the TCAA

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority

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Subchapter D. Administrative Provisions

• 30 TAC §§117.510, 117.520, 117.530, 117.540, 117.560

The amendments are adopted under the Texas Health and Safety Code (Vernon 1992), the Texas Clean Air Act (TCAA), §382 017, which provides the TNRCC with the authority to adopt rules consistent with the policy and purposes of the TCAA

§117 510 Compliance Schedule For Utility Electric Generation All persons affected by the provisions of the undesignated head in Subchapter B of this chapter (relating to Utility Electric Generation) shall be in compliance as soon as practicable, but no later than May 31, 1995 (final compliance date). Additionally, all affected persons shall meet the following compliance schedules and submit written notification to the Executive Director

(1) (No change)

(2) conduct applicable continuous emissions monitoring system (CEMS) or predictive emissions monitoring systems (PEMS) evaluations and quality assurance procedures as specified in §117 113 of this title (relating to Continuous Demonstration of Compliance) according to the following schedules

(A) for equipment and software required pursuant to 40 Code of Federal Regulations (CFR) 75, no later than January 1, 1995; and

(B) for equipment and software not required pursuant to 40 CFR 75, no later than May 31, 1995.

(3) install all nitrogen oxides (NO_x) abatement equipment, implement all NO_x control techniques, and submit the results of the CEMS or PEMS performance evaluation and quality assurance procedures to the Texas Natural Resource Conservation Commission no later than May 31, 1995;

(4) for units operating without CEMS or PEMS, conduct applicable tests for initial demonstration of compliance as specified in §117.111 of this title (relating to Initial Demonstration of Compliance); and submit the results by April 1, 1994, or as early as practicable, but in no case later than May 31, 1995;

(5) for units operating with CEMS or PEMS and complying with the NO_x emission limit on a rolling 30-day average, conduct the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title and submit the results of the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117 113 of this title (relating to Continuous Demonstration of Compliance) no later than July 31, 1995,

(6) for units operating with CEMS or PEMS and complying with the NO_x emission limit in pounds per hour on a block one-hour average, conduct the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title and submit the results of the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.113 of this title by May 31, 1995,

(7) conduct applicable tests for initial demonstration of compliance with the NO_x emission limit for fuel oil firing, in accordance with §117. 111(d)(2) of this title, and submit test results within 60 days after completion of such testing, and

(8) no later than May 31, 1995, submit a final control plan for compliance in accordance with §117.115 of this title (relating to Final Control Plan Procedures).

§117 520 Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources All persons affected by the provisions of the undesignated head in Subchapter B of this chapter (relating to Commercial, Institutional, and Industrial Sources) shall be in compliance as soon as practicable, but no later than May 31, 1995 (final compliance date). All affected persons shall meet the following compliance schedules and submit written notification to the Executive Director:

(1) submit a plan for compliance in accordance with §117.209 of this title (relating to Initial Control Plan Procedures) according to the following schedule:

(A) for major sources of nitrogen oxides (NO_x) which have units subject to emission specifications under this chapter, submit an initial control plan for all such units no later than April 1, 1994,

(B) for major sources of NO_x which have no units subject to emission specifications under this chapter, submit an initial control plan for all such units no later than September 1, 1994,

(C) for major sources of NO_x subject to either subparagraphs (A) or (B) of this paragraph, submit the information required by §117.209(c), (6), (7), and (9) of this title no later than September 1, 1994,

(2) (No change)

(3) for units operating without continuous emissions monitoring system (CEMS) or predictive emissions monitoring systems (PEMS), conduct applicable tests for initial demonstration of compliance as specified in §117 211 of this title (relating to Initial Demonstration of Compliance), and submit the results by April 1, 1994, or as early as practicable, but in no case later than May 31, 1995;

(4) for units operating with CEMS or PEMS and complying with the NO_x emission limit on a rolling 30-day average, conduct the applicable tests for the initial demonstration of compliance as specified in §117 211 of this title and submit the results of the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117 213 of this title (relating to Continuous Demonstration of Compliance) no later than July 31, 1995,

(5) for units operating with CEMS or PEMS and complying with the NO_x emission limit in pounds per hour on a block one-hour average, conduct the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title and submit the results of the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.213 of this title by May 31, 1995, and

(6) no later than May 31, 1995, submit a final control plan for compliance in accordance with §117 215 of this title (relating to Final Control Plan Procedures)

§117 540 Phased Reasonably Available Control Technology (RACT).

(a) The owner or operator affected by the provisions of this chapter (relating to Control of Air Pollution from Nitrogen Compounds) who determines that compliance by May 31, 1995 is not practicable may submit a petition for phased RACT. The process for submitting a petition and receiving approval shall be based on the following

(1) (No change)

(2) The owner or operator of the affected unit or units shall submit information in the petition to the Texas Natural Resource Conservation Commission (TNRCC) and a copy to the United States Environmental Protection Agency (EPA) Regional Office in Dallas which will demonstrate all of the following.

(A) compliance by May 31, 1995 is impracticable due to the unavailability of nitrogen oxides (NO_x) abatement equipment, engineering services, or construction labor, system unreliability, manufacturing unreliability, equipment unreliability, or other technological and economic factors as the TNRCC determines are appropriate,

(B)-(D) (No change)

(3)-(4) (No change)

(5) Within 30 days of receiving a petition for phased RACT, the Executive Director shall inform the applicant in writing that the petition is complete or that additional information is required If the petition is deficient, the notification shall state any additional information required The requested information correcting the deficiency shall be received by the Executive Director within 30 days of the date of the letter notifying the applicant of the deficiency

(6) The Executive Director shall approve or deny the petition within 90 days of receiving an administratively complete phased RACT petition. The Executive Director shall approve a petition for phased RACT if the Executive Director determines that compliance is not practicable by May 31, 1995, because of either the unavailability of nitrogen oxides abatement equipment, engineering services, or construction labor, system unreliability, manufacturing unreliability, equipment unreliability; or other technological and economic factors as the TNRCC determines are appropriate.

(7) Any person affected by the Executive Director's decision to deny a petition for phased RACT or to deny a revision to an approved phased RACT petition

may appeal the decision to the Commission within 30 days after the date of the decision. Such appeal is to be taken by written notification to the Executive Director. 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. Approved petitions for phased RACT may be revised by the Executive Director upon a showing of just cause by the applicant.

(8) Approval of a phased RACT schedule by the TNRCC does not waive any applicable federal requirements or eliminate the need for approval by EPA.

(9) (No change.)

(b) The Executive Director shall initiate a reevaluation of the final compliance dates specified in this undesignated head (relating to Administrative Provisions) one year after the adoption of this chapter. The Executive Director shall evaluate the practicability of all sources complying with §117.105 (relating to Emission Specifications), §117.107 (relating to Alternative System-Wide Emission Specifications), §117.205 (relating to Emission Specifications), §117.207 (relating to Alternative Plant-Wide Emission Specifications), §117.305 (relating to Emission Specifications), §117.405 (relating to Emission Specifications), and §117.223 (relating to Source Cap) of this title by May 31, 1995. The Executive Director shall base the evaluation on the information contained in the control plans required by §§117.109, 117.209, 117.309, and 117.409 of this title (relating to Initial Control Plan Procedures). In evaluating the practicability of compliance by May 31, 1995, the Executive Director shall take into consideration the availability of NO_x abatement equipment, engineering services, or construction labor; system unreliability; manufacturing unreliability; equipment unreliability; or other technological and economic factors as the TNRCC determines are appropriate. Within 15 months after adoption of this chapter, the Executive Director shall publish notice in the *Texas Register* of the intent to either retain or extend by rulemaking the final compliance dates of this undesignated head.

(c) The Executive Director may approve the use of a mobile source emission reduction credit (MERC) to achieve NO_x emissions reductions equivalent to those required by this chapter, on an interim basis from May 31, 1995 to the date of final compliance, for a period not to exceed 36 months. Any plan involving the use of a MERC may be approved if the Executive Director determines that it conforms to the provisions of §117.570 of this title (relating to Trading) and §114.29 of this title (relating to Accelerated Vehicle Retirement Program). Executive Director approval does not necessarily constitute satisfaction of all federal requirements, nor eliminate the need for approval by the EPA.

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

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Director, Legal Division
Texas Natural Resource Conservation Commission

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For further information, please call: (512) 239-0615

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• 30 TAC §117.580

The repeal is adopted under the Texas Health and Safety Code (Vernon 1992), the Texas Clean Air Act (TCAA), §382.017, which provides the TNRCC with the authority to adopt rules consistent with the policy and purposes of the TCAA.

This agency hereby certifies that the rule as adopted has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

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Director, Legal Division
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For further information, please call: (512) 239-0615

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Chapter 334. Underground and Aboveground Storage Tanks

Suchapter A. General Provisions

• 30 TAC §334.14

The Texas Natural Resource Conservation Commission (TNRCC) adopts new §334.14, concerning the adoption of a memorandum of understanding (MOU) between the Attorney General of Texas and the Texas Natural Resource Conservation Commission, with changes to the proposed text as published in the March 4, 1994, issue of the *Texas Register* (19 TexReg 1535).

The MOU complies with the Environmental Protection Agency's (EPA's) requirements as delineated in 40 Code of Federal Regulations, §281.42. This federal rule on state program approval requires states to provide for public intervention in the state civil enforcement process.

The TNRCC received one comment from Exxon Company, USA, who recommended that the word "that" be deleted from the beginning of paragraphs 5, 6, 7, 8 and 9 for ease in reading and interpretation. The TNRCC has made this change as suggested so that each paragraph in the memorandum of understanding (MOU) is consistent and easier to understand.

The new section is adopted under the Texas Water Code, §5.103 (Vernon 1988), which provides the TNRCC with the authority to adopt any rules necessary to carry out the powers and duties under the Texas Water Code and other laws of this state, and Texas Water Code, and other laws of this state.

The section is also adopted under the Texas Water Code §5.104 (Vernon 1988), which provides the requirements for a memorandum of understanding between state agencies when the responsibilities addressed are not otherwise specified in the Texas Water Code.

§334.14. Memorandum of Understanding Between the Attorney General of Texas and the Texas Natural Resource Conservation Commission.

(a) Applicability. This MOU applies to civil enforcement proceedings and complaints filed on storage tanks subject to this chapter. Pursuant to the Texas Water Code, §5.104, the Texas Natural Resource Conservation Commission adopts a MOU between the Texas Natural Resource Conservation Commission (TNRCC) and the Attorney General of Texas. The MOU contains the TNRCC's and the Attorney General's interpretation concerning intervention in the civil enforcement process under the Texas Water Code. This section applies as follows.

(1) The Texas Water Commission (now the Texas Natural Resource Conservation Commission, TNRCC) was designated as the state agency for the regulation of underground storage tanks by enactment of Senate Bill 779 of the 70th Texas Legislature, 1987.

(2) The Texas Water Code authorizes the Texas Natural Resource Conservation Commission to have instituted civil suits for injunctive relief and the assessment and recovery of a civil penalty, whenever it appears that a person has violated, or is violating or threatening to violate, any provision of the Texas Water Code, or of any rule, permit, or other order of the Texas Natural Resource Conservation Commission.

(3) The Texas Water Code provides that at the request of the executive director of the Texas Natural Resource Conservation Commission, the Attorney General of Texas shall institute and conduct a suit in the name of the State of Texas for injunctive relief or to recover a civil penalty, or for both injunctive relief and penalty.