The Texas Natural Resource Conservation Commission (commission) adopts amendments to §117.10, concerning Definitions; §§117.205, 117.207, 117.208, 117.209, 117.211, 117.213, 117.219, and 117.223, concerning Commercial, Institutional and Industrial Sources; and §117.520 and §117.570, concerning Administrative Provisions. The commission adopts these amendments to Chapter 117, concerning Control of Air Pollution from Nitrogen Compounds, and revisions to the State Implementation Plan (SIP) in order to conform with the U.S. Environmental Protection Agency's (EPA) revised ozone transport policy and allow the Beaumont/Port Arthur (BPA) ozone nonattainment area's attainment date to be extended. The changes require certain lean-burn stationary engines in BPA to meet new emission specifications and other requirements in order to reduce nitrogen oxides (NO_x) emissions and ozone air pollution. Secondarily, in an effort to improve implementation of Chapter 117, applicable to existing major stationary sources of NO_x in the BPA, Dallas/Fort Worth (DFW), and Houston/ Galveston (HGA) ozone nonattainment areas, the commission adopts changes to Chapter 117 which: eliminate the requirement to operate wood-fired boilers with flue gas sensor-based trim, add an option to monitor exhaust flow instead of fuel flow, and clarify several other requirements and rule references.

Sections 117.205, 117.211, 117.213, 117.223, and 117.570 are adopted with changes to the proposed text as published in the July 16, 1999 issue of the *Texas Register* (24 *TexReg* 5436). Sections 117.10, 117.207, 117.208, 117.209, 117.219, and 117.520 are adopted without changes and will not be republished.

BACKGROUND

The BPA ozone nonattainment area, an area defined by Hardin, Jefferson, and Orange Counties, is currently designated moderate under the Federal Clean Air Act (FCAA) and, thus, was required to attain the one-hour ozone standard by November 15, 1996. BPA did not attain the standard by that date and also will not attain the standard by November 15, 1999, the attainment date for serious areas. EPA is authorized to redesignate an area to the next higher classification ("bump up") if it fails to attain by the required date.

However, as an alternative to bump-up, EPA policy allows consideration of the effect of transport of ozone or its precursors from an upwind area. The HGA ozone nonattainment area is upwind of BPA and influences BPA's air quality to such an extent that without reductions from HGA, BPA may not be able to attain the standard solely from its own local reductions. EPA's revised transport policy allows a downwind area such as BPA to have its attainment date extended to no later than the attainment date for the upwind area, without being bumped up.

On April 16, 1999, EPA published notice in the *Federal Register* (64 FR 18864) that in order for BPA to take advantage of this policy, the commission must submit to EPA an acceptable SIP revision (by November 15, 1999) which includes any local control measures needed for expeditious attainment and proof that all applicable local control measures required under the moderate classification have been adopted.

The commission's strategy is to meet the "expeditious attainment" requirement of EPA's policy by providing for additional NO_x reductions in BPA. The adopted lean-burn engine NO_x rule for BPA will provide a substantial portion of these reductions. In addition, FCAA, §182(f) requires that NO_x Reasonably Available Control Technology (RACT) be applied to all major sources of NO_x in moderate and above ozone nonattainment areas. The adopted revisions will also implement NO_x RACT requirements for lean-burn gas-fired engines in BPA.

The lean-burn engine rulemaking represents "Phase I" of the state's NO_x rulemaking activities for the BPA attainment demonstration. Under this schedule, these adopted rules for lean-burn engines will be submitted to EPA by November 15, 1999. These Phase I NO_x rules are part of the reductions modeled for an ozone episode showing transport from HGA to BPA. The agency has conducted modeling for another ozone episode, in which BPA's local emission contributions predominate in the formation of ozone, showing the need for more NO_x reductions in BPA in order for the area to attain the 1-hour ozone standard. The commission is developing additional NO_x rules in order for BPA to attain under these local contributions conditions. These "Phase II" rules needed for attainment are expected to be submitted to EPA in April, 2000.

EXPLANATION OF ADOPTED RULES

The adopted change to §117.10, concerning Definitions, adds a definition of "thirty-day rolling average" to the rule, in response to a request for clarification from a monitoring system vendor. The definition is taken from Title 40 Code of Federal Regulations (CFR) Part 60, Subpart Db, the definition of steam generating unit operating day in §60.41b, and the NO_x compliance procedure in §60.46b(e)(3).

This clarification is consistent with the preamble discussion in the original NO_x RACT rule (18 TexReg 3427, May 28, 1993).

The adopted change to §117.205(b), concerning Emission Specifications, relocates the averaging time requirements from the beginning of the subsection to new paragraphs (7) and (8) and uses a listing format to make the text less dense and more readable. The adopted changes to §117.205(b)(5) and §117.207(d) and (e), concerning Alternative Plant-wide Emission Specifications, make rule terminology more consistent by substituting the term "sum" for "average" in reference to heat input weighting.

The adopted new §117.205(e) and revised §117.205(g)(6), now renumbered (h)(6), add an emission specification for lean-burn gas-fired engines in BPA. The adopted limit of 3.0 grams NO_x per horsepower-hour (g/hp-hr) is consistent with previously established NO_x RACT rules in a number of other states. A block one-hour average compliance period for the emission limits was proposed and adopted. In addition, in order to allow the pipeline compressor engines to continue to operate efficiently, higher short term emissions are allowed under an optional, 30-day rolling average compliance period. This option requires use of one of several monitoring options to demonstrate emissions compliance. The adopted limit of 3.0 g carbon monoxide (CO)/hp-hr is consistent with the existing emission specification for rich-burn engines. The purpose of this requirement is to ensure that the NO_x control technique selected does not unnecessarily increase CO emissions.

The adopted changes to §117.205(g)(3), now relettered (h)(3), §117.207(f)(4), §117.209(b)(2), concerning Initial Control Plan Procedures, and §117.213(a)(1)(C), now relettered (a)(1)(A)(iii), concerning Continuous Demonstration of Compliance, clarify the exemption from NO_x emission specifications for boilers and industrial furnaces (BIFs) regulated by EPA at 40 CFR 266, Subpart H. The exemption became effective on June 9, 1993 with the original NO_x RACT rules and has not been modified since. However, on June 19, 1998, EPA excluded from regulation under Subpart H some hazardous waste-derived fuels which are comparable to certain commercial liquid fuels ("comparable fuels"). The adopted revision clarifies that the exemption applies to BIFs regulated by the version of the EPA rules which were in effect on June 9, 1993. Although it may be appropriate to eventually bring some or all of the original BIFs into the Chapter 117 emission specifications, it would only be appropriate to do so through the rulemaking process, which allows for public notice and comment. The commission will evaluate the feasibility of NO_x controls from BIFs in BPA during the development of Phase II rules.

The adopted change to §117.207(f) updates a cross-reference. The adopted change to §117.208(d)(1), concerning Operating Requirements, exempts wood-fired boilers from the requirement to operate with oxygen (O_2) or CO trim. Boiler trim uses feedback from exhaust gas O_2 or CO sensors to minimize the amount of combustion air fed to a boiler. With trim, gas-fired boilers are typically capable of operating around 2% exhaust O_2; in this range, a reduction of O_2 reduces NO_x formation. In contrast, wood-fired boilers typically need to operate in the range of 7% to 8% exhaust O_2 in order to burn the fuel completely and minimize CO. In this O_2 range, the NO_x production rate (pound per million British thermal units of heat input) increases with tighter O_2 control. Therefore, NO_x reductions caused by fuel efficiency improvement (reducing the total amount of fuel fired reduces emissions) due to combustion trim are likely to be negated by the increased NO_x production rate. Furthermore, the moisture content of wood fuel varies greatly. The moisture variability may make the operation of trim control unworkable on wood-fired boilers. Because it is ineffective for NO_x control and the operation is challenging, the commission has eliminated the boiler trim requirement for wood-fired boilers.

The adopted change to §117.211(d), concerning Initial Demonstration of Compliance, clarifies the rule language by substituting "March 21, 1999" for "the effective date of this rule as revised." The specific effective date was not inserted here in the previous revision because the effective date is not known with certainty until after rule language is adopted. The adopted change to §117.211(g)(8) corrects the cross reference to the CEMS requirements, changing §117.211(d) to §117.211(e).

In response to a suggestion from a representative of an affected source with six fuels fed to one unit, the adopted new §117.213(a)(2) adds the option of using a calibrated exhaust flow monitor instead of fuel flow meters for units which are monitored with a NO_x continuous emission monitoring system (CEMS). Installation of one exhaust flow monitor may be less expensive than installing multiple fuel flow meters. Procedures for calibration of exhaust flow monitors are available in existing federal regulations in 40 CFR Part 75, Appendix A, and are referenced to assure the accuracy of the monitoring. Properly calibrated and quality assured exhaust flow monitors should be at least as accurate in determining the NO_x mass emission rate as fuel flow meters.

The adopted new §117.213(b)(2) lists units not required to monitor exhaust O_2 under §117.213(b). First, the list excludes units currently exempt from the Chapter 117 NO_x emission specifications. It would not be logical for the monitoring to apply to a unit that is not currently subject to an emission specification. It would be more appropriate to establish the monitoring requirements for these exempt units concurrently with any new emission specifications necessary for future attainment demonstration rules. Second, the adopted §117.213(b)(2)(B) excludes process heaters which operate with CO_2 CEMS from the §117.213(b) exhaust O_2 monitoring requirement in order to correct a drafting error in the previous rulemaking which eliminated this alternative. Excess air may be measured by either O_2 or CO_2, and process heaters are not required to measure O_2 for trim purposes, as is required for boilers under §117.208(d)(1). Therefore, monitoring excess air with CO_2 CEMS is an acceptable alternative to O_2 monitors for process heaters. Last, the adopted §117.213(b)(2)(C) excludes wood-fired boilers from the §117.213(b) exhaust O_2 monitoring, to be consistent with the elimination of the requirement to operate these boilers with O_2 trim.

The adopted new §117.213(b)(3) clarifies that the O_2 monitors required by subsection (b) are not subject to the location and calibration requirements of the O_2 monitors required by subsection (e). The O_2 monitors required by subsection (b) are for uses such as inputs for predictive monitoring, boiler trim control, and process control. Most units already operate with O_2 monitors for combustion process control. Therefore, because of the potential costs of imposing retroactive requirements on existing monitors, the O_2 monitors should only be required to meet the location specifications and quality assurance requirements referenced in subsection (e) if the monitors are used to monitor diluent under subsection (e). However, if new O_2 monitors are necessitated as a result of subsection (b), subsection (e) requirements should be considered the appropriate guidance for the location and calibration of the monitors. Flexibility in applying the O_2 monitoring requirement is consistent with the preamble discussion in the original NO_x RACT rule (18 TexReg 3436, May 28, 1993). Because subsection (b) currently does not specify compliance with the location and calibration requirements of subsection (e), the adopted changes clarify, but do not lessen, existing requirements.

Other adopted changes update a cross-reference in §117.213(c)(2)(A) and reduce the number of words used in §117.213(c)(2)(B) without changing the intended meaning. In response to a request for clarification from the regulated community, §117.213(f)(5)(C)(ii) is revised by substituting the words "Performance Specifications" for "appropriate procedures." This wording change clarifies that the reference to §117.213(f)(5)(A)(i)(I)-(III) does not include the three load testing specified in §117.213(f)(5)(A)(i). The adopted changes to §117.213(i) and (m) correct rule cross-references.

The adopted changes to §117.219(e)(2), concerning Notification, Recordkeeping, and Reporting Requirements, revise the criteria for reporting excess emissions caused by catalytic converter or air-fuel ratio controller malfunction, to more generally include excess emissions caused by emission control system failures. This change is adopted to expand the reporting to include the newly regulated category of lean-burn engine emissions. The adopted change to §117.219(f)(1) adds a recordkeeping requirement for exhaust flow monitoring, in case that option (as newly adopted) is used. The adopted revision to §117.219(f)(2) requires recordkeeping of maintenance of the engine emissions control system for components other than catalytic converters or air-fuel ratio controllers. This change ensures that records of maintenance of lean-burn engine emissions control systems are kept and made available upon request. The adopted revision to §117.219(f)(5) updates a rule cross-reference.

The adopted changes to §117.223, concerning Source Cap, establish new baseline dates for owners or operators who wish to use the source cap compliance option for compliance with the new lean-burn engine NO_x emission specification in BPA. New §117.223(g)(6) and (k)(3) modify §117.223(g)(3), moving the starting period from November 15, 1990, to September 10, 1993, for creditable shutdowns which occurred before the new lean-burn engine rule effective date. The attainment demonstration is based on the modeling inventory for September 10, 1993, the controlling date of the modeled ozone episode. This change ensures that sources that shut down before 1993 and were not included in the attainment demonstration modeling inventory are not eligible for generating reduction credits for compliance with the lean-burn engine NO_x specification. Reductions from such shutdowns have been relied upon in the current BPA ozone attainment demonstration and are not surplus. The end date for creditable shutdowns is moved from the original NO_x RACT rule effective date of June 9, 1993, to December 31, 1999, approximately the new lean-burn engine rule effective date. In addition, §117.223(k)(3) modifies §117.223(g)(3) to require the heat input used to calculate emission credit be consistent with the heat input used to represent the source's emissions in the attainment demonstration modeling inventory. This change ensures that creditable reductions are surplus. Also, the heat input baseline is updated to a three-year period between January 1, 1997 and December 31, 1999 to make the rule easier to use. As time passes, heat input records become increasingly hard to obtain on a unit-by-unit basis for the period specified in the original NO_x RACT rule.

The adopted changes to §117.520, concerning Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources, subdivide the sections into a BPA and HGA subsection to allow for separate compliance schedules for sources located in BPA and HGA and to correct a cross-reference error. The commission adopts a compliance date for BPA lean-burn engine NO_x RACT of November 15, 2001. This time frame allows a two-year implementation of the necessary control measures and is consistent with the time period for compliance with the other NO_x RACT emission specifications in Chapter 117.

Adopted changes to §117.570(b)(2), concerning Trading, correct drafting errors in three defined terms used in the equations for calculating reduction credits. The adopted change to the heat input term "H_j" in §117.570(b)(2) adds "except that the term may not include one standard deviation of the average daily heat input for the period in either calculation" at the end of the definition. The definition of "H_j" cross-references the calculation procedure in §117.223 of this title. However, the cross-reference was not meant to include one standard deviation to be added to the actual historical average daily heat input, as is allowed for operational flexibility under the source cap. Adding one standard deviation to an emission credit would be inconsistent with the policy goal that traded credits be real. An adopted change to the emission limit term "R_{Aj}," adds "H_j" and deletes "period in §117.223(g)(3) of this title" at the end of the definition. The change simplifies the definition without changing its meaning. An additional adopted change to "R_{Aj}" modifies the definition as it applies to discrete emission reduction credits (DERCs). The term "R_{Aj}" is the lower of any enforceable emission limitation applicable during the generation period or of the baseline emission rate. This revision clarifies that the baseline for calculating DERCs is based on the lower of applicable limits or actual rates, and not the NO_x RACT limits, until after the NO_x RACT compliance date. An adopted change to the enforceable emission rate term "R_{Bj}," distinguishes a separate meaning for the term "R_{Bj}" for DERCs. Since DERCs may be generated before the rule compliance date and the emission rate in the rule is not enforceable during this period, the average actual emission rate is applicable rather than the enforceable emission rate.

An adopted change in §117.570(b)(4) clarifies that the paragraph is applicable to emission reduction credits (ERCs), rather than both ERCs and DERCs. One purpose of DERCs is to generate credit for early reductions, and requiring the source cap allowable to be reduced after the compliance date by the amount of the DERC credit removes the incentive to create early reductions.

In addition, the equations in §117.570(c)(1), (c)(2), and (d) are readopted to correct printing errors in the version of the rule filed with the Secretary of State on December 3, 1997. This previous version of the adopted rule inadvertently contains the bold and bracket markings of the proposal, indicating text to be added and removed.

Other adopted changes to §117.570 establish new baseline dates for owners or operators who wish to use the trading compliance option for compliance with the adopted new lean-burn engine NO_x emission specification in BPA. New §117.570(f) specifies that emission reductions which were relied upon in the attainment demonstration modeling inventory may not be used for generating emission reduction credits to comply with the lean-burn engine NO_x specification of §117.205(e) of this title. In addition, §117.570(f) modifies §117.570(b)(1)(A), moving the starting period for creditable reductions from 1990 to 1993. These changes ensure that creditable reductions have not been relied upon in the attainment demonstration and are therefore surplus. New §117.570(f)(2)-(4) update the rule effective date to

December 31, 1999, approximately the new lean-burn engine rule effective date, and cross reference the date adjustments in §117.223(k) to ensure consistency between §117.223 and §117.570.

FINAL REGULATORY IMPACT ANALYSIS

The commission has reviewed the rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and has determined that the rulemaking is not subject to §2001.0225. "Major environmental rule" means a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure and that may adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. Although one of the adopted amendments requires significant capital expenditures on certain lean-burn engines, the rule is not a "major environmental rule" as defined in the Texas Government Code. The BPA area contains more than 60 plants engaged in the natural gas, oil refining, or chemical manufacturing sectors of the economy. These plants contain more than 1000 discrete facilities, or emission units. The newly adopted Chapter 117 requirements affect a small portion of these sectors, since they will require capital expenditures at only five of the plants and 27 of the emission units. In addition, the productivity of the engines, as measured by fuel efficiency, may be slightly improved by the modifications necessary to comply with the requirements. Further, the adopted amendment requiring the lean-burn engine emission specification does not meet any of the four applicability criteria of a "major environmental rule." Section 2001.0225 applies only to a major environmental rule the result of which is to:

(1) exceed a standard set by federal law, unless the rule is specifically required by state law;

(2) exceed an express requirement of state law, unless the rule is specifically required by federal law;

(3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program or;

(4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

The amendments implement requirements of the FCAA. FCAA, §110 requires states to submit SIPs which contain enforceable measures to achieve the National Ambient Air Quality Standards (NAAQS). The adopted rules, which reduce ambient NO_x and ozone in BPA, are being submitted to EPA as one of several measures of the required new attainment demonstration. These rules also implement NO_x RACT for lean-burn engines in BPA and improve the implementation of NO_x RACT in BPA (moderate), DFW (serious), and HGA (severe). FCAA, §182(f) requires any moderate and above ozone nonattainment area to implement NO_x RACT. The adopted amendments to the rules do not exceed an express requirement of a state law, but were developed specifically in order to meet the RACT requirements established under federal law. The rule amendments are also a necessary portion of an ozone attainment demonstration SIP for BPA, required by FCAA, §110. There is no contract or delegation agreement that covers the topic that is the subject of this rulemaking. Therefore, these adopted amendments do not exceed a standard set by federal law, exceed an express requirement of state law, nor exceed a requirement of a delegation agreement. In addition, the changes are not adopted solely under the general rulemaking authority of the commission but are adopted under specific authority to comply with the requirements of federal regulations.

Other adopted modifications to Chapter 117 do not meet the definition of “major environmental rule” in the Texas Government Code. Specifically, the amendments which eliminate the requirement to operate wood-fired boilers with flue gas sensor-based trim of combustion air; the option to monitor exhaust flow instead of fuel flow; and the amendments that clarify certain commission rules applicable to existing major stationary sources of NO_x emissions do not require additional control equipment or measures. The eliminated requirements and added flexibility contained in these sections of the adopted amendments may result in positive fiscal implications to the regulated community. Therefore, these amendments do not adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

No comments on the regulatory impact analysis were received.

TAKINGS IMPACT ASSESSMENT

The commission has prepared a takings impact assessment for these sections under Texas Government Code, §2007.043. The following is a summary of that assessment. The specific purposes of these amendments are: to develop a new attainment demonstration SIP for the ozone NAAQS for BPA, to implement lean-burn engine NO_x RACT in BPA, and to improve the implementation of NO_x RACT in BPA, DFW, and HGA. As adopted, certain major sources located in BPA are now required to install new emission control equipment, and implement new operating, reporting, and recordkeeping requirements. Installation of the necessary control equipment could conceivably place a burden on private, real property. However, under Texas Government Code, §2007.003(b)(4) and (b)(13), Chapter 2007 does not apply to this action. Under §2007.003(b)(4), Chapter 2007 does not apply to an action that is reasonably taken to fulfill an obligation mandated by federal law. The adopted amendments will implement requirements of FCAA, §110 and §182(f). Also, §2007.003(b)(13) states that Chapter 2007 does not apply to an action that: (1) is taken in response to a real and substantial threat to public health and safety; (2) is designed to significantly advance the health and safety purpose; and (3) does not impose a greater burden than is necessary to achieve the health and safety purpose. This action is taken in response to the BPA area exceeding the federal ambient air quality standard for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient NO_x and ozone levels in BPA. Attainment of the ozone standard will eventually require substantial NO_x reductions. Any NO_x reductions resulting from the current rulemaking are no greater than what the best scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard. In addition, the requirements are expressed as performance specifications and the rules contain multiple compliance methods to minimize costs of compliance.

Other adopted changes eliminate the requirement to operate wood-fired boilers with flue gas sensor trim of combustion air, add the option to monitor exhaust flow instead of fuel flow, and clarify certain commission rules applicable to existing major stationary sources of NO_x emissions. These changes do not require additional control equipment or measures, and do not materially affect private real property. The eliminated requirement and added flexibility will result in cost savings; any new costs associated with clarified requirements are not significant.

COASTAL MANAGEMENT PROGRAM CONSISTENCY REVIEW

The commission has determined that this rulemaking action relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et seq.), and the commission's rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with the Texas Coastal Management Program. As required by 31 TAC §505.11(b)(2) and 30 TAC §281.45(a)(3), relating to actions and rules subject to the CMP, commission rules governing air pollutant emissions must be consistent with the applicable goals and policies of the CMP. The commission has reviewed this rulemaking action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and has determined that this rulemaking action is consistent with the applicable CMP goals and policies. The primary CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations at 40 CFR to protect and enhance air quality in the coastal area. The rules, which require additional reductions of air emissions in BPA and improve the implementation and enforceability of the rules in BPA, HGA, and DFW, will result in reductions of ambient NO_x and ozone concentrations. The adopted rules are consistent with the applicable CMP policy because they are consistent with Title 40. Title 40, Part 51, sets out requirements for states to prepare, adopt, and submit implementation plans for the attainment of the NAAQS. The adopted rules will be submitted to EPA under these requirements.

HEARINGS AND COMMENTERS

A public hearing for this rulemaking was held in Beaumont on August 9, 1999, followed by a comment period which ended on August 23, 1999. No oral testimony regarding the proposed revisions to

Chapter 117 was received at the public hearing. Nine persons submitted written comments on the proposal: Clark Refining and Marketing, Incorporated (Clark), Du Pont (submitted on behalf of Du Pont by Brown McCarroll & Oaks Hartline, L.L.P.), Enron Gas Pipeline Group (Enron), Entergy Services, Inc. (Entergy), EPA, KN Energy, Inc. (KN), Louisiana-Pacific Corporation (L-P), Texas Chemical Council (TCC), and TXU Business Services (TXU). Commenters generally supported or did not oppose the proposed revisions, but recommended revisions.

ANALYSIS OF TESTIMONY

Entergy and TXU supported the proposed new definition of "thirty-day rolling average" and suggested a parallel rule definition for "24-hour rolling average."

The commission agrees that the suggested "24-hour rolling average" definition appears to be appropriate and consistent with the new "thirty-day rolling average" definition. However, the Texas Administrative Procedure Act and Texas Register rules make including this new definition more appropriate in the Phase II of Chapter 117 revisions, anticipated to be proposed in December, 1999. Nitric and adipic acid manufacturing sources are also required to comply with a 24-hour rolling average, and the definition recommended by the utilities would need to be adjusted to reflect the way those sources operate. The commission has made no change in response to this comment.

EPA commented that eliminating the exemption for fluid catalytic cracking units (including CO boilers) and boilers and industrial furnaces (BIFs) would yield an additional reduction in NO_x emissions.

The commission recognizes that most of these sources are individually major; however evaluating reductions from these categories is outside the scope of the current rulemaking, which is limited to the lean-burn engines.

EPA supported the proposed lean-burn engine exemption level of 300 hp for BPA as appropriate to the FCAA's RACT requirements but noted that additional reductions could be achieved if the exemptions were even lower as has been implemented in other parts of the country such as California.

There are no readily identifiable reductions achievable through lowering the lean-burn engine hp exemption. There are only six identifiable high operating hour engines at major sources among the 178 engines in the 1997 BPA emissions inventory which would be affected by lowering the exemption to 50 hp (a typical level in California). Because these six are rich-burn engines, the exemption level is outside the scope of the present rule making. Even so, the potential reduction from these rich-burn engines is only 0.6 ton per day. The commission has made no change in response to this comment.

Clark said that engines of all sizes that are used for emergency purposes only, such as firewater supply, back-up electrical power, back-up compressed air and storm water drainage should be exempt from the proposed rules.

Chapter 117 continues to exempt from emission specifications engines of all sizes that are used for emergency purposes only. For gas-fired engines rated more than 300 hp in BPA that provide

back-up electrical power or compressed air, use of exemption §117.203(6)(b) requires monitoring of hours of operation, at §117.213(i), to ensure that the usage does not exceed 850 hours per year. The commission has made no change in response to this comment.

Du Pont asked the commission to provide reasonable assurance that the adopted measures will be effective in achieving the goal of ozone attainment.

Air quality modeling and other studies specific to BPA have concluded that reducing NO_x in BPA effectively reduces ozone in BPA. The science of ozone air pollution control indicates that reductions from a variety of sources are necessary to attain the ozone standard and that reductions from any one source or type of sources, although necessary, are not sufficient to solve the problem. Although the lean-burn engine rule by itself does not represent reductions sufficient to allow the area to attain the ozone standard, the requirements are part of a continuing series of requirements for emission reductions which will ultimately lead to ozone attainment.

NO_x reductions outside BPA are also needed, because the science also shows that ozone transported into the area has sometimes contributed decisively to the area's ozone exceedances. However, because distant emissions are diluted over the distance of travel, NO_x emission reductions in BPA, pound for pound, will tend to be more effective in reducing ozone in BPA than distant NO_x reductions, such as from HGA. Because industrial point source emissions comprise a high portion of BPA's total NO_x, an effective ozone reduction strategy must continue to include industrial sources in BPA. The commission has made no change in response to this comment.

Du Pont said that current estimates are that the reductions in the 300-1000 horsepower range will cost approximately $6,000/ton and expressed concern that the additional reductions obtained from engines in this range are not warranted based on cost effectiveness. Clark said that the benefits of requiring additional control on emissions from the 300-1000 hp engines were not cost effective, based on their calculation of the cost effectiveness for these engines at $4800/ton reduced.

Du Pont did not provide any details to substantiate the basis of their cost estimate and the information Clark provided was not complete enough to replicate their estimate, but nonetheless appears to have been based on tons per day of NO_x reduced. Expressing cost effectiveness in terms of annualized cost divided by annual tons reduced is standard in the field of air pollution control. The total annualized cost was detailed in the cost note contained in the notice of proposed rulemaking (24 Texas Register 5439-5440 and 5560, July 16, 1999). Commenters did not challenge the methodology or any specifics of the cost note (except, perhaps K-N, which based their comments on review of an incomplete version of the proposal). The total annualized cost identified in the cost note for the 13 affected engines in the 300-1000 hp range is $632,000. The total annual NO_x reduced is 569 tons, or 70% of the 813 tons reported by Du Pont in the latest inventory. The resulting cost effectiveness of $1110/ton for the 300-1000 hp engines is very much in the range of estimates of other NO_x RACT measures previously adopted by the commission and is considered reasonable. The marginal control cost, represented by the two 330 hp engines, is also reasonable at $1750/ton because it is in the range of estimated marginal costs for previously adopted NO_x RACT requirements for rich-burn engines. The reductions from the 300-1000 hp

engines represent about 28% of the total NO_x reductions established by the lean-burn engine rule. The commission has made no change in response to this comment.

KN Energy made comments about a lack of details in the cost estimates.

KN Energy's comments were prepared on the basis of having obtained only the text portion of the cost note, as posted by the Texas Register electronically. All graphical information such as tables and equations are currently published only in the Tables and Graphics section of the hardcopy version of the Texas Register. The commenter was directed to the published engine cost table, which contains detailed cost estimates for each affected engine.

Du Pont said that the proposal does not provide any substantiating documentation that other sources have implemented the technology and that controls are feasible for all engines in BPA.

The EPA's NO_x RACT guidance document, "NO_x Emissions from Stationary Reciprocating Internal Combustion Engines," EPA-453/R-93-032, July 1993, referenced in the proposal, contains documentation that other sources have implemented low emissions combustion (LEC) technology. An appendix of this document contains a list of engine sources that have implemented NO_x reduction technology. The list was obtained from one of many air pollution control districts in California that have promulgated NO_x regulations for lean-burn engines. A 1999 report by the Interstate Natural Gas Association of America lists 160 large gas-fired lean-burn engines retrofit

with LEC, owned by five companies. This report also references other documents which list smaller engines.

The original equipment manufacturer (OEM) cost estimates in the proposal provided documentation that LEC controls are feasible for all affected engines in BPA. In developing the proposal, the commission staff provided the engine OEMs the models of all the affected engines, and where known, the ages of the engines. Based on this information, staff asked the OEMs to estimate the cost of control to meet a 3.0 g NO_x/hp-hr limit. In addition to estimating the control costs for the specific make and model engines in the 300-1000 hp range, the relevant OEM confirmed that previous retrofits have included engines of the 100 hp/cylinder class, characteristic of the Du Pont engines.

Du Pont said that the proposal does not provide documentation relative to the vast differences in age or types of service that exist for the lean burn engines in the BPA area.

Any differences in age or service type among the affected engines are not critical to the issue of emission control, nor do the differences appear to be vast. The affected lean-burn engines are all slow speed, large-bore, gas-fired engines used to continuously compress gases. The heavy metal parts of this type of engine last essentially indefinitely, while smaller wearing parts are replaced at periodic major engine overhauls. The refinery compressors were installed in 1938, the chemical plant compressors in 1946 and 1948, and the engines of one of the pipeline compressor stations in 1950 and 1952.

Du Pont asked the commission to provide reasonable assurance that the adopted measures will be the most effective in terms of dollars expended per unit of air quality improvement.

Because many control measures will be required to attain the ozone air quality standard, it is impossible that each measure alone is the most effective in terms of dollars expended per unit of air quality improvement. The commission staff and local industries collectively identified lean-burn engines as a logical category to regulate, considering EPA NO_x RACT guidance, emissions quantity, and the absence of NO_x limits for most of these engines. The cost effectiveness of $1110/ton for the smaller engines meets EPA's recommendation of a minimum range of $160 to $1300 per ton for NO_x RACT, and is within the commission's estimated cost ranges for earlier regulated NO_x RACT categories. Finally, the reductions from the engines, with relatively short stacks, may tend to produce greater local ozone reduction benefit compared to sources with taller stacks, due to the more localized dispersion from shorter stacks.

TCC commented that the rationale provided for proposing to regulate the lean-burn engines was based on being consistent with other states' regulations. They said the commission should not base rulemaking on actions of other states, but to establish environmental controls and requirements on specific environmental needs and scientific, technical evaluations, including cost benefit.

The commission did not mean to imply by the format of the proposal preamble that the sole rationale for implementing requirements for lean-burn engines was the fact that other states have done so. The commission believes that the background information in the proposal preamble

identified the environmental need for additional NO_x reductions in BPA and the cost note provided the technical information necessary to evaluate the cost effectiveness of the rule.

Du Pont said that an analysis of RACT alternatives should incorporate a site specific geographic component, and that the commission has failed to consider this factor. Du Pont referenced the guidance contained in the appendices of EPA's General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990 (57 *Fed. Reg.* 18,070).

The site specific geographic component contained in the April, 1992 General Preamble appendices referenced by Du Pont is not mentioned in the EPA's guidance concerning the NO_x RACT provisions of the 1990 FCAA. The EPA's November 25, 1992 Supplement to the General Preamble (57 *Fed. Reg.* 55,620) addresses issues related to the new NO_x provisions of the 1990 FCAA, including EPA's interpretation and guidance on implementation of NO_x RACT. The Supplement recommends NO_x RACT rules set either a source-category-wide presumptive limit or a procedure for establishing case-by-case limits. The adopted rule sets a source-category-wide presumptive limit for lean-burn engine NO_x in BPA. The existing Chapter 117 NO_x RACT rules also contain an alternate case-specific emission provision in order to address the possibility that a presumptive limit is not appropriate in certain cases.

Enron commented that the OEM quotations for a 3 g/hp-hr limit was based on full load and speed, and provided the OEM's graph of predicted emissions compliance with 3 g/hp-hr as a function of engine torque and speed. Enron operates their engines in a load following mode, varying engine speed to move natural gas more efficiently through the pipeline. Enron recommended raising the limit or allowing compliance based on average emissions of 3 g/hp-hr.

The commission agrees with Enron that the combination of high torque and reduced speed operation increases NO_x emissions for these engines. Operation at an average rate of 3 g NO_x/hp-hr would achieve the approximately 70% emissions reduction the rule is intended to achieve. In response to the comment, the commission has revised the rule to include the option of complying with the limit as a 30-day rolling average. The owner or operator complying on a 30-day rolling average would either install a CEMS or a predictive emissions monitoring system (PEMS) in accordance with §117.213, or monitor engine speed and torque and compute predicted NO_x as a function of these two variables. This requires the owner or operator to monitor and record data representative of engine torque and speed at sufficient frequency to accurately compute the 30-day average NO_x. The predicted NO_x as a function of the torque and speed data may be based on curves or equations supplied by the OEM, but must be shown to be consistent with the required initial and biennial compliance testing. The initial compliance test under the speed/torque monitoring option includes the three one-hour test runs specified in §117.211(e), conducted at full load. Compliance with a 3 g NO_x/hp-hr limit at maximum rated torque and speed is not an issue with LEC. The commission has adopted the 30-day rolling average compliance option for lean-burn engines in new §117.205(e)(2).

Enron and KN Energy said that the proposed 3 g/hp-hr standard should not be looked at as a precedent for other areas outside the BPA area, because there are engines outside BPA which can't meet the standard proposed for BPA.

The commission did not develop a lean-burn rule proposal for the HGA and DFW areas concurrently with the BPA proposal because those areas will probably require even lower lean-burn engine NO_x limits for ozone attainment. The commission recognizes that for some engines, all located outside of BPA, the lack of available OEM LEC retrofits may increase the cost of control. This issue does not affect the cost analysis in the current rulemaking, since OEM LEC technology is available for all the affected BPA engines.

L-P expressed support for the proposed removal of the requirement to operate wood-fired boilers with oxygen trim. They recommended amendment to §117.213(b)(2) to include wood-fired boilers on the list of equipment for which oxygen monitors are not required by regulation.

The commission agrees that L-P's proposed change is consistent with the deletion of the requirement to operate wood-fired boilers with oxygen trim, and has added an exclusion from oxygen monitoring requirements for wood-fired boilers. This change does not eliminate the requirement to monitor either oxygen or carbon dioxide as diluent for larger wood-fired boilers operating a NO_x CEMS under 117.213(e). The adopted exclusion is located at §117.213(b)(2)(C).

Clark and the TCC opposed the proposed restrictions on the use of trading credits to comply with the new lean-burn engine emission specifications. Clark said they justified the expense of retrofitting BACT on their grandfathered facilities on the basis that emission reductions would be creditable within the existing policies of the commission.

When the BPA lean-burn engine NO_x rule was proposed, the purpose of resetting the baseline for emission trades used to meet the proposed reduction requirements was to avoid double counting of reductions in the concurrently proposed BPA ozone attainment demonstration SIP. At the time, the proposed SIP relied on a large decrease in point source NO_x emissions, based on the difference in actual emissions of startup new emission sources and shutdown existing sources during the period from January 1, 1990 to December 31, 1996. These shutdown reductions were counted as part of the growth projection for the proposed SIP. The shutdowns that occurred between 1990 and 1996 also comprise the majority of the currently banked NO_x emissions in BPA. However, in the adopted SIP, the commission has revised the basis of the point source growth estimate and is no longer relying on all the shutdowns that occurred in the 1990-1996 time period. The growth estimate in the adopted SIP does not directly rely on the shutdowns. Nonetheless, the controlled, projected modeling inventory in the attainment demonstration SIP creates a budget for the area. Sources that shut down before 1993 were not included in the modeling and are not part of the attainment demonstration SIP budget. These shutdowns have been relied on for the attainment demonstration. On the other hand, sources that shut down or reduced emissions after 1993 would have been included in the attainment demonstration modeling inventory. These reductions, in excess of the amount in the attainment demonstration inventory, are surplus to the attainment

demonstration and should be creditable under the trading provisions of the Chapter 117 attainment demonstration rules. The commission has adopted §117.223(g) and (k) and §117.570(f) to allow credits generated after the modeling inventory of 1993 to be used for compliance with the adopted new lean-burn NO_x reduction requirements.

TCC said the compliance schedule for lean-burn engines should be based on area needs and flexibility in the SIPs to allow for evaluation of monitoring. Clark said that the compliance schedule for the lean-burn engine rule should not be sooner than 2003.

The lean-burn engine rule is required by the RACT and attainment provisions of the FCAA, with statutory deadlines of 1995 and 1996, respectively. The rules were delayed by the need to improve the science. The science has been advanced greatly; the finding that reducing NO_x effectively reduces BPA's ozone is no longer controversial. BPA has not attained the ozone standard and the FCAA mandate to implement the controls as expeditiously as practicable is pertinent. The time between the rule effective date and the final compliance date for the BPA lean-burn engine rule is about two years. This schedule is consistent with previously adopted NO_x RACT compliance schedules and recognizes that approximately two years are required for industry to procure funds, purchase, install, and test emission control equipment and monitoring systems. The commission has made no change in response to this comment.

In addition to the comments received in response to the notice of proposed rulemaking, several drafting errors have come to the commission's attention that have been corrected in the adopted

rule. A cross reference in §117.211(g)(8)(A) has been corrected, revising the reference from §117.213(d) to §117.213(e). Also, §117.213(b), which was revised in the previous rulemaking (24 *TexReg* 1784) to improve clarity of the emission monitoring requirements, inadvertently removed the option for process heaters to monitor CO_2 instead of O_2. Excess air may be measured by either O_2 or CO_2, and process heaters are not required to measure O_2 for trim purposes, as is required for boilers under §117.208(d)(1). Therefore, monitoring excess air with CO_2 CEMS is an acceptable alternative to O_2 monitors for process heaters. The commission has adopted new §117.213(b)(2)(B) to reinstate this option.

In addition, the commission adopts three revisions to the trading rules, at §117.570(b) to correct earlier drafting errors. Revisions to §117.570, concerning Trading, adopted on December 19, 1997 (22 TexReg 12533), created a new type of emissions trading credit known as the DERC. The DERC is quantified after the emission reduction used to generate it has been implemented and an endpoint is defined, has a limited period of use, and is measured in tons. DERCs allow credit for early or temporary reductions in real emissions. However, DERCs cease or must be recalculated after any applicable compliance date affecting the generating unit. The adopted changes make necessary distinctions between ERCs and DERCs in the equations used to calculate these quantities and are consistent with the clear intent of the December 19, 1997 rulemaking.

The first adopted revision in §117.570(b)(2) changes the definition of "R_{Aj}" as it applies to DERCs. The term "R_{Aj}" is the lower of any enforceable emission limitation applicable during the generation period, or of the baseline emission rate. This revision clarifies that the baseline for

calculating DERCs is based on the lower of applicable limits or actual rates, and not the NO_x RACT limits, until after the NO_x RACT compliance date.

The second adopted revision in §117.570(b)(2) changes the definition of the term "R_{Bj}" as it applies to DERCs. The term "R_{Bj}" is defined as the average emission rate, rather than the enforceable emission rate, that applies to emission unit *j* during the generation period. Because DERCs may be generated before the rule compliance date, and the emission rate in the rule is not enforceable during this period, the average actual emission rate is applicable rather than the enforceable emission rate.

The third revision changes §117.570(b)(4)(A), which previously specified that the source cap allowable under §117. 223, concerning Source Cap, must be reduced by the amount of creditable reductions claimed for units participating in the source cap. The adopted rule change clarifies that this requirement is applicable only to ERCs, rather than both ERCs and DERCs. The paragraph, adopted with the original trading rule applicable to ERCs, was not intended to subsequently apply to DERCs. If the paragraph applied to DERCs, it would require the source cap allowable to be reduced after the compliance date by the amount of the DERC credit generated before the compliance date. This would remove the incentive to create DERCs and to make early NO_x reductions.

STATUTORY AUTHORITY

The amendments are adopted under Texas Health and Safety Code, TCAA, §382.011, which establishes the ability of the commission to control the quality of the state's air; §382.012, which requires the commission to develop a general, comprehensive plan for the proper control of the state's air; §382.016, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; and §382.051(d), which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

SUBCHAPTER A : DEFINITIONS

§117.10

§117.10. Definitions.

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

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

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

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

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

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

(3) **Auxiliary steam boiler** - Any combustion equipment within an electric power generating system, as defined in this section, that is used to produce steam for purposes other than generating electricity.

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

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

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

(7) **Btu** - British thermal unit.

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

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

(10) **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 Beaumont/Port Arthur, Dallas/Fort Worth, or Houston/Galveston ozone nonattainment areas.

(11) **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.

(12) **Heat input** - The chemical heat released due to fuel combustion in a unit, using the higher heating value of the fuel. This does not include the sensible heat of the incoming combustion air. In the case of carbon monoxide (CO) boilers, the heat input includes the enthalpy of all regenerator off-gases and the heat of combustion of the incoming carbon monoxide and of the auxiliary fuel. The enthalpy change of the fluid catalytic cracking unit regenerator off-gases refers to the total heat content of the gas at the temperature it enters the CO boiler, referring to the heat content at 60 degrees Fahrenheit, as being zero.

(13) **High heat release rate** - A ratio of boiler design heat input to firebox volume (as bounded by the front firebox wall where the burner is located, the firebox side waterwall, and extending

to the level just below or in front of the first row of convection pass tubes) greater than or equal to 70,000 British thermal units (Btu) per hour per cubic foot.

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

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

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

(17) **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.

(18) **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.

(19) **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.

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

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

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

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

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

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

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

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

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

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

(23) **Megawatt (MW) rating** - The continuous MW rating or mechanical equivalent by a gas turbine manufacturer at ISO conditions, without consideration to the increase in gas turbine shaft output and/or the decrease in gas turbine fuel consumption by the addition of energy recovered from exhaust heat.

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

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

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

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

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

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

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

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

(32) **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.

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

(34) **Stationary internal combustion engine** - A reciprocating engine either attached to a foundation or if not so attached is operated or is intended to be operated at a single facility for more

than six months, including any replacement engine for a specific application which lasts or is intended to last for more than six months.

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

(36) **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.

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

(38) **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. Any emission credits resulting from the operation of such units shall be limited to the cumulative maximum rated capacity of the units replaced.

(39) **Utility boiler or steam generator** - Any combustion equipment owned or operated by a municipality or Public Utility Commission of Texas regulated utility, fired with solid, liquid, and/or gaseous fuel, used to produce steam for the purpose of generating electricity.

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

SUBCHAPTER B : COMBUSTION AT EXISTING MAJOR SOURCES

DIVISION 2 : COMMERCIAL, INSTITUTIONAL, AND INDUSTRIAL SOURCES

§§117.205, 117.207, 117.208, 117.209, 117.211, 117.213, 117.219, 117.223

The amendments are adopted under Texas Health and Safety Code, TCAA, §382.011, which establishes the ability of the commission to control the quality of the state's air; §382.012, which requires the commission to develop a general, comprehensive plan for the proper control of the state's air; §382.016, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; and §382.051(d), which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

§117.205. 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 nitrogen oxides (NO_x) emission limit in effect on June 9, 1993, under a permit issued pursuant to Chapter 116 of this title

(relating to Control of Air Pollution by Permits for New Construction or Modification) and the emission limits of subsections (b)-(d) of this section shall apply, except that:

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

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

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

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

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

(3) For any unit placed into service after June 9, 1993 and before the final compliance date as specified in §117.520 of this title (relating to Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources or the final compliance date as approved under the provisions of §117.540 of this title (relating to Phased Reasonably Available Control Technology (RACT)), as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 pursuant to Chapter 116 of this title and the emission limits of subsections (b)-(d) of this section shall apply. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.207 or §117.223 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

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

(1) gas-fired boilers, as follows:

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

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

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

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

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

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

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

(A) based on air preheat temperature:

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

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

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

(B) based on firebox temperature:

(i) process heaters with a firebox temperature less than 1,400 degrees Fahrenheit, 0.10 lb NO_x/MMBtu of heat input;

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

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

(3) liquid fuel-fired boilers and process heaters, 0.30 lb NO_x/MMBtu of heat input;

(4) wood fuel-fired boilers and process heaters, 0.30 lb NO_x/MMBtu of heat input;

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

(6) for any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, a multiplier of up to 1.25 times the appropriate emission limit in this subsection may be used for that eight-hour period. The total hydrogen volume in all gaseous fuel streams will be divided by the total gaseous fuel flow volume to determine the volume percent of hydrogen in the fuel supply. The multiplier may not be used to increase limits set by permit;

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

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

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

(8) for units which do not operate with a NO_x CEMS or PEMS under §117.213 of this title, the emission limits shall apply in pounds per hour, as specified in paragraph 7(B) of this subsection.

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

(d) No person shall allow the discharge into the atmosphere from any gas-fired, rich-burn, stationary, reciprocating internal combustion engine, emissions in excess of a block one-hour average of 2.0 grams NO_x per horsepower hour (g NO_x/hp-hr) and 3.0 g CO/hp-hr for engines which are:

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

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

(e) No person shall allow the discharge into the atmosphere from any gas-fired, lean-burn, stationary, reciprocating internal combustion engine rated 300 hp or greater and located in the Beaumont/Port Arthur ozone nonattainment area, emissions in excess of 3.0 g NO_x/hp-hr and 3.0 g CO/hp-hr, either as:

(1) a block one-hour average limit; or

(2) a thirty-day rolling average limit. The owner or operator must ensure compliance with a 30-day rolling average using:

(A) a PEMS or CEMS under §117.213 of this title; or

(B) a monitoring system which

(i) computes predicted emissions as a function of engine speed and torque using curves or equations supplied by the engine manufacturer or developed through engine testing, which

(I) may be adjusted by engine testing; and

(II) must be shown to be consistent with the required initial and biennial compliance testing; and

(ii) monitors and records data representative of engine torque and speed at sufficient frequency to accurately compute the 30-day average NO_x.

(f) No person shall allow the discharge into the atmosphere from any boiler or process heater subject to NO_x emission specifications in subsection (a) or (b) of this section, CO emissions in excess of the following limitations:

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

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

(3) for units equipped with CEMS or PEMS for CO, the limits of paragraphs (1) and (2) of this subsection shall apply on a rolling 24-hour averaging period. For units not equipped with CEMS or PEMS for CO, the limits shall apply on a one-hour average.

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

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

(1) any 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 were regulated as existing facilities by the United States Environmental Protection Agency at 40 Code of Federal Regulations Part 266, Subpart H, as was in effect on June 9, 1993;

(4) fluid catalytic cracking units (including CO boilers);

(5) supplemental waste heat recovery units used in turbine exhaust ducts;

(6) any lean-burn, stationary, reciprocating internal combustion engine located in the Houston/Galveston or Dallas/Fort Worth ozone nonattainment area; and

(7) any stationary gas turbine with an MW rating less than 10.0 MW.

§117.207. Alternative Plant-wide Emission Specifications.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.205 of this title (relating to Emission Specifications) by achieving equivalent NO_x emission reductions obtained by compliance with a plant-wide emission limitation. Any owner or operator who elects to comply with a plant-wide emission limit shall reduce emissions of NO_x from affected units so that if all such units were operated at their maximum rated capacity, the plant-wide emission rate of NO_x from these units would not exceed the plant-wide emission limit as defined in §117.10 of this title (relating to Definitions).

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

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

(A) the mass of NO_x emitted per unit of energy input (pound NO_x per million (MM) Btu), on a rolling 30-day average period; or

(B) as the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average.

(2) For boilers and process heaters which do not operate with CEMS or PEMS, the emission limits shall apply as the mass of NO_x emitted per hour (pounds NO_x per hour), on a block one-hour average.

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

(4) For stationary internal combustion engines, the emission limits shall apply in units of grams NO_x per horsepower-hour (g NO_x/hp-hr) on a block one-hour average.

(c) An owner or operator of any gaseous and liquid fuel-fired unit which derives more than 50% of its annual heat input from gaseous fuel shall use only the appropriate gaseous fuel emission limit of §117.205 of this title at maximum rated capacity in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate while firing gas, calculated in accordance with subsection (a) of this section. The owner or operator shall also:

(1) comply with the assigned maximum allowable emission rate while firing gas only;

(2) comply with the liquid fuel emission limit of §117.205 of this title while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing allowable emission rate and the liquid fuel emission limit of §117.205 of this title while operating on liquid and gaseous fuel concurrently.

(d) An owner or operator of any gaseous and liquid fuel-fired unit which derives more than 50% of its annual heat input from liquid fuel shall use a heat input weighted sum of the appropriate gaseous and liquid fuel emission specifications of §117.205 of this title in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate, calculated in accordance with subsection (a) of this section.

(e) An owner or operator of any unit operated with a combination of gaseous (or liquid) and solid fuels shall use a heat input weighted sum of the appropriate emission specifications of §117.205 of this title in calculating the plant-wide emission limit and shall assign to the unit the maximum allowable NO_x emission rate, calculated in accordance with subsection (a) of this section.

(f) Units exempted from emission specifications in accordance with §117.205(h) of this title are also exempt under this section and shall not be included in the plant-wide emission limit, except as follows. The owner or operator of exempted units as defined in §117.205(h) of this title may opt to include one or more of an entire equipment class of exempted units into the alternative plant-wide emission specifications.

(1) Low annual capacity factor boilers, process heaters, gas turbines, or engines as defined in §117.10 of this title are not to be considered as part of the opt-in class of equipment.

(2) The ammonia and carbon monoxide emission specifications of §117.205 of this title apply to the opt-in units.

(3) The individual NO_x emission limit that is to be used in calculating the alternative plant-wide emission specifications is the lower of any applicable permit emission specification determined in accordance with §117.205(a) of this title and the specification of paragraph (4) of this subsection.

(4) The equipment classes which may be included in the alternative plant-wide emission specifications and the NO_x emission rates that are to be used in calculating the alternative plant-wide emission specifications are listed in the following table, §117.207(f) OPT-IN UNITS:
Figure: 30 TAC §117.207(f)(4)

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

(1) For each affected boiler and process heater, the rate is the product of its maximum rated capacity and its NO_x emission specification of §117.205 of this title.

(2) For each affected stationary internal combustion engine, the rate is the product of the applicable NO_x emission specification of §117.205 of this title (expressed in g/hp-hr) and the engine manufacturer's rated heat input (expressed in MMBtu/hr) at the engine's hp rating; divided by the product of the engine manufacturer's rated heat rate (expressed in Btu/hp-hr) at the engine's hp rating and $454(10^6)$.

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

Where:

In-stack NO_x	=	NO_x(allowable) x (1 - $\%H_2O$/100) x [20.9 - $\%O_2$/(1 - $\%H_2O$/100)]/5.9
NO_x (allowable)	=	the applicable NO_x emission specification of §117.205(c) of this title (expressed in ppmv NO_x at 15% O_2, dry basis).
$\%H_2O$	=	the volume percent of water in the stack gases, as calculated from the manufacturer's data, or other data as approved by the executive director, at MW rating and ISO flow conditions.

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

(4) Each affected gas-fired boiler and process heater firing gaseous fuel which contains more than 50% hydrogen (H_2) by volume, over an annual basis, may be adjusted with a multiplier of up to 1.25 times the product of its maximum rated capacity and its NO_x emission specification of §117.205 of this title.

(A) Double application of the H_2 content multiplier using this paragraph and §117.205(b)(6) of this title is not allowed.

(B) The multiplier may not be used to increase a limit set by permit.

(C) The fuel gas composition must be sampled and analyzed every three hours.

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

§117.208. Operating Requirements.

(a) The owner or operator shall operate any unit subject to the emission limitations of §117.205 of this title (relating to Emission Specifications) in compliance with those limitations.

(b) The owner or operator shall operate any unit subject to the plant-wide emission limit of §117.207 of this title (relating to Alternative Plant-wide Emission Specifications) such that the assigned maximum nitrogen oxides (NO_x) emission rate for each unit expressed in units of the applicable emission limit and averaging period, is in accordance with the list approved by the executive director pursuant to §117.215 of this title (relating to Final Control Plan Procedures).

(c) The owner or operator shall operate any unit subject to the source cap emission limits of §117.223 of this title (relating to Source Cap) in compliance with those limitations.

(d) All units subject to the emission limitations of §§117.205, 117.207, or 117.223 of this title shall be operated so as to minimize NO_x emissions, consistent with the emission control techniques selected, over the unit's operating or load range during normal operations. Such operational requirements include the following.

(1) Each boiler, except for wood-fired boilers, shall be operated with oxygen (O_2) or carbon monoxide (CO) trim (or both).

(2) Each boiler and process heater controlled with forced flue gas recirculation (FGR) to reduce NO_x emissions shall be operated such that the proportional design rate of FGR is maintained, consistent with combustion stability, over the operating range.

(3) Each boiler and process heater controlled with induced draft FGR to reduce NO_x emissions shall be operated such that the operation of FGR over the operating range is not restricted by artificial means.

(4) Each unit controlled with steam or water injection shall be operated such that injection rates are maintained to limit NO_x concentrations to less than or equal to the NO_x concentrations achieved at maximum rated capacity (corrected to 15% O_2 on a dry basis for gas turbines).

(5) Each unit controlled with post combustion control techniques shall be operated such that the reducing agent injection rate is maintained to limit NO_x concentrations to less than or equal to the NO_x concentrations achieved at maximum rated capacity.

(6) Each stationary internal combustion engine controlled with nonselective catalytic reduction shall be equipped with an automatic air-fuel ratio (AFR) controller which operates on exhaust

O_2 or CO control and maintains AFR in the range required to meet the engine's applicable emission limits.

(7) Each stationary internal combustion engine shall be checked for proper operation of the engine by recorded measurements of NO_x and CO emissions at least quarterly and as soon as practicable after each occurrence of engine maintenance which may reasonably be expected to increase emissions, O_2 sensor replacement, or catalyst cleaning or catalyst replacement. Stain tube indicators specifically designed to measure NO_x concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x analyzers shall also be acceptable for this documentation.

§117.209. Initial Control Plan Procedures.

(a) The owner or operator of any major source of nitrogen oxides (NO_x) located in the Beaumont/Port Arthur or Houston/Galveston ozone nonattainment area 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.

(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 executive director, 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 million British thermal units 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 MMBtu/hr which were regulated as existing facilities by EPA at 40 Code of Federal Regulations, Part 266, Subpart H, as was in effect on June 9, 1993, 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 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 hp or greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater; all stationary gas turbines with an 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 Area and Mobile Emissions Assessment and Industrial Emissions Assessment Sections of the commission, and the emission point numbers as listed on the Maximum Allowable Emissions Rate Table of any applicable commission 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) a list of units to be controlled and the type of control to be applied for all such units, including an anticipated construction schedule;

(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 this division. 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) the calculation of the CO boiler heat input;

(B) the calculation of the appropriate CO boiler volumetric inlet and exhaust flowrates; and

(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) 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) The owner or operator of all units which are subject to the emission limitations of this division (relating to Commercial, Institutional, and Industrial Sources) must test the units as follows.

(1) Test for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions while firing gaseous fuel or, as applicable:

(A) hydrogen (H_2) fuel for units which may fire more than 50% H_2 by volume; and

(B) liquid and solid fuel.

(2) Units which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions.

(3) Test all units belonging to equipment classes which are elected to be included in

(A) the alternative plant-wide emission specifications as defined in §117.207(f) of this title (relating to Alternative Plant-Wide Emission Specifications); or

(B) the source cap as defined in §117.223(b)(4) of this title (relating to Source Cap).

(4) Initial demonstration of compliance testing shall be performed in accordance with the schedule specified in §117.520 of this title (relating to Compliance Schedule For 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 the emission limits of this division. Test results shall be reported in the units of the applicable emission limits and averaging periods.

(c) Any continuous emissions monitoring system (CEMS) or any predictive emissions monitoring system (PEMS) required by §117.213 of this title (relating to Continuous Demonstration of Compliance) shall be installed and operational before conducting testing under subsection (a) of this section. Verification of operational status shall, as a minimum, include completion of the initial relative accuracy test audit and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system.

(d) Early testing conducted before March 21, 1999 may be used to demonstrate compliance with the standards specified in this division, if the owner or operator of an affected facility demonstrates to the executive director that the prior compliance testing at least meets the requirements of subsections (a), (b), (c), (e), and (f) of this section. For early testing, the compliance stack test report required by subsection (g) shall be as complete as necessary to demonstrate to the executive director that the stack test was valid and the source has complied with the rule. The executive director reserves the right to request compliance testing or CEMS or PEMS performance evaluation at any time.

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

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

(2) Test Method 10, 10A, or 10B (40 CFR 60, Appendix A) for CO;

(3) Test Method 3A or 20 (40 CFR 60, Appendix A) for O_2;

(4) Test Method 2 (40 CFR 60, Appendix A) for exhaust gas flow and following the measurement site criteria of Test Method 1, 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 United States Environmental Protection Agency (EPA); or

(6) EPA-approved alternate test methods or minor modifications to these test methods as approved by the executive director, as long as the minor modifications meet the following conditions:

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

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

(f) Initial compliance with the emission specifications of this division for units operating with CEMS or PEMS in accordance with §117.213 of this title, shall be demonstrated after monitor certification testing using the CEMS or PEMS as follows.

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

(2) For units complying with a NO_x emission limit on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable is used to determine compliance with the NO_x emission limit.

(3) For units complying with a CO emission limit, on a rolling 24-hour average, any 24-hour period is used to determine compliance with the CO emission limit.

(4) For units complying with §117.223 of this title, a rolling 30-day average of total daily pounds of NO_x emissions from the units are monitored (or calculated in accordance with §117.223(c) of this title) for 30 successive source operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission limit. The 30-day average emission rate is

calculated as the average of all daily emissions data recorded by the monitoring and recording system during the 30-day test period. There must be no exceedances of the maximum daily cap during the 30-day test period.

(g) Compliance stack test reports must include the following minimum contents.

(1) Introductory information. Provide background information pertinent to the test, including:

(A) company name, address, and name of company official responsible for submitting report;

(B) name and address of testing organization;

(C) names of persons present, dates and location of test;

(D) schematic drawings of the unit being tested, showing emission points, sampling sites, and stack cross section with the sampling points labeled and dimensions indicated;

(E) description of the process being sampled; and

(F) facility identification number (FIN) used to identify the unit in the final control plan.

(2) Summary information. Provide summary information, including:

(A) a summary of emission rates found, reported in the units of the applicable emission limits and averaging periods, and compared with the applicable emission limit;

(B) the maximum rated capacity, normal maximum capacity, and actual operating level of the unit during the test (in MMBtu/hr, horsepower (hp), or megawatts (MW), as applicable), and description of the method used to determine such operating level;

(C) the operating parameters of any active NO_x control equipment during the test, (for example, percent flue gas recirculation, ammonia flow rate, etc); and

(D) documentation that no changes to the unit have occurred since the compliance test was conducted that could result in a significant change in NO_x emissions.

(3) Procedure. Describe the procedures used and operation of the sampling train and process during the test, including:

(A) a schematic drawing of the sampling devices used with each component designated and explained in a legend;

(B) a brief description of the method used to operate the sampling train and procedure used to recover samples; and

(C) deviation from reference methods, if any.

(4) Analytical technique. Provide a brief description of all analytical techniques used to determine the emissions from the source.

(5) Data and calculations. Include all data and calculations, of:

(A) field data collected on raw data sheets;

(B) log of process operating levels, including fuel data;

(C) laboratory data, including blanks, tare weights, and results of analysis; and

(D) emission calculations.

(6) Chain of custody. Include a listing of the chain of custody of the emission or fuel test samples, as applicable.

(7) Appendix. Provide:

(A) calibration work sheets for sampling equipment;

(B) collection of process logs of process parameters;

(C) brief resume/qualifications of test personnel; and

(D) description of applicable continuous monitoring system, as applicable.

(8) Monitor certification reports. Monitor certification reports must contain:

(A) information which demonstrates compliance with the certification requirements of §117.213(e) or (f) of this title for CEMS or PEMS, as applicable; and

(B) the relative accuracy test audit information specified in 40 CFR 60, Appendix B, Performance Specification 2, Section 9.

§117.213. Continuous Demonstration of Compliance.

(a) Totalizing fuel flow meters. The owner or operator of units listed in this subsection shall install, calibrate, maintain, and operate a totalizing fuel flow meter to individually and continuously measure the gas and liquid fuel usage. A computer which collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer.

(1) The units are the following:

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

(i) boilers;

(ii) process heaters;

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

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

(B) stationary, reciprocating internal combustion engines not exempt by §117.203(6) or (8) of this title (relating to Exemptions);

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

(D) fluid catalytic cracking unit boilers using supplemental fuel.

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

(b) Oxygen (O_2) monitors.

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

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

(B) process heaters with a rated heat input:

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

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

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

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

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

(C) wood-fired boilers.

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

(c) NO_x monitors.

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

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

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

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

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

(E) units for which the owner or operator elects to comply with the NO_x emission specifications of this division using a pound per MMBtu limit on a 30-day rolling average.

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

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

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

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

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

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

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

(2) sample CO as follows:

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

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

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

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

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

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

(A) Section 60.13;

(B) Appendix B:

(i) Performance Specification 2, for NO_x;

(ii) Performance Specification 3, for diluent; and

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

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

(2) Monitor diluent, either O_2 or CO_2.

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

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

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

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

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

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

(2) Monitor diluent, either O_2 or CO_2:

(A) using a CEMS

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

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

(B) using a PEMS.

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

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

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

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

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

(A) perform the following alternative initial certification tests:

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

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

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

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

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

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

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

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

(B) further demonstrate PEMS accuracy and precision for at least one unit of a category of equipment by performing RATA and statistical testing in accordance with subparagraph (A) of this paragraph for each of three successive quarters, beginning:

(i) no sooner than the quarter immediately following initial certification; and

(ii) no later than the first quarter following the final compliance date; and

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

(i) at normal load operations;

(ii) using the Performance Specifications of paragraph (5)(A)(i)(I)-(III) of this subsection; and

(iii) at the following frequency:

(I) semiannually; or

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

(-a-) for diluent, is no greater than 1.0 % O_2 or CO_2, for diluent measured by reference method at less than 5% by volume; or

(-b-) for CO, is no greater than 5 parts per million by volume.

(6) The owner or operator shall, for each alternative fuel fired in a unit, certify the PEMS in accordance with paragraph (5)(A) of this subsection unless the alternative fuel effects on NO_x, CO, and O_2 (or CO_2) emissions were addressed in the model training process.

(7) The PEMS shall be subject to the approval of the executive director.

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

(1) Use the methods specified in §117.211(e) of this title (relating to Initial Demonstration of Compliance).

(2) Sample:

(A) on a biennial calendar basis; or

(B) within 15,000 hours of engine operation after the previous emission test, under the following conditions:

(i) install and operate an elapsed operating time meter; and

(ii) submit, in writing, to the executive director and any local air pollution agency having jurisdiction, biennially after the initial demonstration of compliance:

(I) documentation of the actual recorded hours of engine operation since the previous emission test; and

(II) an estimate of the date of the next required sampling.

(h) Monitoring for gas turbines less than 30 MW. The owner or operator of any stationary gas turbine rated less than 30 MW using steam or water injection to comply with the emission specifications of §117.205 or §117.207 of this title (relating to Alternative Plant-wide Emission Specifications) shall either:

(1) install, calibrate, maintain, and operate a NO_x CEMS or PEMS in compliance with this section and monitor CO in compliance with subsection (d) of this section; or

(2) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption.

(A) The system shall be accurate to within $\pm$ 5.0%.

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

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

(i) Run time meters. The owner or operator of any stationary gas turbine or stationary internal combustion engine claimed exempt using the 850 hours per year exemption of §117.203(6)(B) of this title shall record the operating time with an elapsed run time meter.

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

(1) The total H_2 volume flow in all gaseous fuel streams to the unit will be divided by the total gaseous volume flow to determine the volume percent of H_2 in the fuel supply to the unit.

(2) Fuel gas analysis shall be tested according to American Society of Testing and Materials (ASTM) Method D1945-81 or ASTM Method D2650-83, or other methods which are demonstrated to the satisfaction of the executive director and the EPA to be equivalent.

(3) A gaseous fuel stream containing 99% H_2 by volume or greater may use the following procedure to be exempted from the sampling and analysis requirements of this subsection.

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

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

(C) The owner or operator shall certify that the gaseous fuel stream containing H_2 will continuously remain, as a minimum, at 99% H_2 by volume or greater during its use as a fuel to the combustion unit.

(k) Data used for compliance. After the initial demonstration of compliance required by §117.211 of this title, the methods required in this section shall be used to determine compliance with the emission specifications of this division. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission limitations.

(l) Enforcement of NO_x limits. If compliance with §117.205 of this title is selected, no unit subject to §117.205 of this title shall be operated at an emission rate higher than that allowed by the emission specifications of §117.205 of this title. If compliance with §117.207 of this title is selected, no unit subject to §117.207 of this title shall be operated at an emission rate higher than that approved by the executive director pursuant to §117.215(b) of this title (relating to Final Control Plan Procedures).

(m) Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.205(h)(2) of this title (relating to Definitions), shall notify the executive director within seven days if the Btu/yr or hour-per-year limit specified in §117.10 of this title, as appropriate, is exceeded.

(1) If the limit is exceeded, the exemption from the emission specifications of §117.205 of this title shall be permanently withdrawn.

(2) Within 90 days after loss of the exemption, the owner or operator shall submit a compliance plan detailing a plan to meet the applicable compliance limit as soon as possible, but no later than 24 months after exceeding the limit. The plan shall include a schedule of increments of progress for the installation of the required control equipment.

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

§117.219. Notification, Recordkeeping, and Reporting Requirements.

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

(b) Notification. The owner or operator of an affected source shall submit notification to the executive director, as follows:

(1) 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) Reporting of test results. The owner or operator of an affected unit shall furnish the executive director and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.211 of this title and any CEMS or PEMS relative accuracy test audit (RATA) conducted under §117.213 of this title:

(1) within 60 days after completion of such testing or evaluation; and

(2) not later than the compliance schedule specified in §117.520 of this title (relating to Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system under §117.213 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations of this division (relating to Commercial, Institutional, and Industrial Sources) and the monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar semiannual period. Written reports shall include the following information:

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

(A) For gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.213(h)(2) of this title, excess emissions are computed as each one-hour period during which the average steam or water injection rate is below the level defined by the control algorithm as necessary to achieve compliance with the applicable emission limitations in §117.205 of this title (relating to Emission Specifications).

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

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

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

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

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

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

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

(2) specific identification, to the extent feasible, of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the engine or emission control system, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

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

(1) For each unit using a CEMS or PEMS in accordance with §117.213 of this title, monitoring records of:

(A) hourly emissions and fuel usage (or stack exhaust flow) for units complying with an emission limit enforced on a block one-hour average; and

(B) daily emissions and fuel usage (or stack exhaust flow) for units complying with an emission limit enforced on a rolling 30-day average. Emissions must be recorded in units of:

(i) pound per million British thermal units (Btu) heat input; and

(ii) pounds or tons per day.

(2) for each internal combustion engine subject to the emission specifications of this division, records of:

(A) emissions measurements required by:

(i) §117.208(7) of this title (relating to Operating Requirements); and

(ii) §117.213(g) of this title; and

(B) catalytic converter, air-fuel ratio controller, or other emissions-related control system maintenance, including the date and nature of corrective actions taken.

(3) for each gas turbine monitored by steam-to-fuel or water-to-fuel ratio in accordance with §117.213(h) of this title, records of hourly:

(A) pounds of steam or water injected;

(B) pounds of fuel consumed; and

(C) the steam-to-fuel or water-to-fuel ratio.

(4) for hydrogen (H_2) fuel monitoring in accordance with §117.213(j) of this title, records of the volume percent H_2 every three hours.

(5) for units claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.205(h)(2), either records of monthly:

(A) fuel usage, for exemptions based on heat input; or

(B) hours of operation, for exemptions based on hours per year of operation.

(6) Records of carbon monoxide measurements specified in §117.213(d)(2) of this title.

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

(8) records of the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.211 of this title.

§117.223. Source Cap.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.205 of this title (relating to Emission Specifications) by achieving equivalent 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 (relating to Alternative Plant-wide Emission Specifications) of this title.

(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:

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

Where:

I = each emission unit in the emission cap

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

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

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 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:

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

Where:

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

H_{mi} = The maximum daily heat input, as certified to the executive director, 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 lbs 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 lbs 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 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 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 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 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 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, Record keeping, 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 semiannual 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 executive director, 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; and

(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.

(6) Shutdowns which occurred before September 10, 1993, may not be used for compliance with the lean-burn engine specification of §117.205(e) of this title.

(h) A unit which has been shut down 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 to comply with the NO_x emission specifications of this division:

(1) applicable in the Houston/Galveston or Beaumont/Port Arthur ozone nonattainment areas, required by November 15, 1999; or

(2) applicable in the Dallas/Fort Worth ozone nonattainment area, required by March 31, 2001.

(i) An owner or operator who chooses to use the source cap option shall include in the initial control plan, if 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 initial 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.

(k) The modified requirements of this subsection are necessary for an owner or operator to use the source cap requirements of this section to achieve compliance with the lean-burn engine NO_x emission specification of §117.205(e) of this title.

(1) In subsection (b) of this section, the dates are modified in the definitions as follows:

(A) H_i, the actual historical average daily heat input, the time period between January 1, 1997, and December 31, 1999, replaces the time period between January 1, 1990, and June 9, 1993; and

(B) R_i, December 31, 1999, replaces June 9, 1993, throughout.

(2) In subsection (g) of this section, the dates are modified as follows:

(A) September 10, 1993, replaces November 15, 1990, throughout;

(B) December 31, 1999, replaces June 9, 1993, throughout; and

(C) January 1, 1997, replaces January 1, 1990.

(3) The actual heat input identified in subsection (g)(3) of this section must be consistent with the heat input used to represent the unit's emissions in the attainment demonstration modeling inventory.

(4) A source which used a source cap to comply with the NO_x emission specifications of this division required by November 15, 1999, must either:

(A) maintain a separate source cap for the lean-burn engines; or

(B) revise an existing source cap to include the lean-burn engines, recalculating the allowable mass emission rates for all units in the cap based on the conditions in paragraphs (1)-(3) of this subsection.

SUBCHAPTER D : ADMINISTRATIVE PROVISIONS

§117.520, §117.570

The amendments are adopted under Texas Health and Safety Code, TCAA, §382.011, which establishes the ability of the commission to control the quality of the state's air; §382.012, which requires the commission to develop a general, comprehensive plan for the proper control of the state's air; §382.016, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; and §382.051(d), which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

§117.520. Compliance Schedule For Commercial, Institutional, and Industrial Combustion Sources.

(a) The owner or operator of each commercial, institutional, and industrial source in the Beaumont/Port Arthur ozone nonattainment area shall comply with the requirements of Subchapter B, Division 2 of this chapter (relating to Commercial, Institutional, and Industrial Sources) as soon as practicable, but no later than the dates specified in this subsection. The owner or operator shall:

(1) for all units, except lean-burn engines subject to paragraph (2) of this subsection, comply with the requirements of Subchapter B, Division 2 of this chapter by November 15, 1999 (final compliance date) and submit to the executive director:

(A) for units operating without continuous emissions monitoring system (CEMS) or predictive emissions monitoring systems (PEMS), the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title (relating to Initial Demonstration of Compliance); by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(B) for units operating with CEMS or PEMS in accordance with §117.213 of this title (relating to Continuous Demonstration of Compliance), the results of:

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

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

(iii) no later than:

(I) November 15, 1999, for units complying with the nitrogen oxides (NO_x) emission limit on an hourly average; and

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

(C) a final control plan for compliance in accordance with §117.215 of this title (relating to Final Control Plan Procedures), no later than November 15, 1999; and

(D) the first semiannual report required by §117.219(d) or (e) of this title (relating to Notification, Recordkeeping, and Reporting Requirements), covering the period November 15, 1999 through December 31, 1999, no later than January 31, 2000; and

(2) for each lean-burn, stationary, reciprocating internal combustion engine subject to §117.205(e) of this title (relating to Emission Specifications), comply with the requirements of Subchapter B, Division 2 of this chapter for those engines as soon as practicable, but no later than November 15, 2001 (final compliance date for lean-burn engines); and

(A) no later than November 15, 2001, submit a revised final control plan which contains:

(i) the information specified in §117.215 of this title as it applies to the lean-burn engines; and

(ii) any other revisions to the source's final control plan as a result of complying with the lean-burn engine emission specifications; and

(B) no later than January 31, 2002, submit the first semiannual report required by §117.219(e) of this title covering the period November 15, 2001 through December 31, 2001.

(b) The owner or operator of each commercial, institutional, and industrial source in the Dallas/Fort Worth ozone nonattainment area shall comply with the requirements of Subchapter B, Division 2 of this chapter as soon as practicable, but no later than March 31, 2001 (final compliance date). The owner or operator shall:

(1) install all NO_x abatement equipment and implement all NO_x control techniques no later than March 31, 2001; and

(2) submit to the executive director:

(A) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title as early as practicable, but in no case later than March 31, 2001;

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

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

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

(iii) no later than:

(I) March 31, 2001, for units complying with the NO_x emission limit on an hourly average; and

(II) May 31, 2001, for units complying with the NO_x emission limit on a rolling 30-day average;

(C) a final control plan for compliance in accordance with §117.215 of this title, no later than March 31, 2001; and

(D) the first semiannual report required by §117.219(d) or (e) of this title, covering the period March 31, 2001 through June 30, 2001, no later than July 31, 2001.

(c) The owner or operator of each commercial, institutional, and industrial source in the Houston/Galveston ozone nonattainment area shall comply with the requirements of Subchapter B, Division 2 of this chapter as soon as practicable, but no later than November 15, 1999 (final compliance date). The owner or operator shall:

(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 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; and

(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) install all NO_x abatement equipment and implement all NO_x control techniques no later than November 15, 1999;

(3) submit to the executive director:

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

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

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

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

(iii) no later than:

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

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

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

(D) the first semiannual report required by §117.219(d) or (e) of this title, covering the period November 15, 1999, through December 31, 1999, no later than January 31, 2000.

§117.570. Trading.

(a) An owner or operator may reduce the amount of emission reductions required by §117.105 or §117.205 of this title (relating to Emission Specifications), §117.107 of this title (relating to Alternative System-Wide Emission Specifications), §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117.223 of this title (relating to Source Cap) by obtaining an emission reduction credit (ERC), mobile emission reduction credit (MERC), discrete emission reduction credit (DERC), or mobile discrete emission reduction credit (MDERC) established in accordance with this section and §101.29 of this title (relating to Emission Credit Banking and Trading). Any ERCs or DERCs for nitrogen oxides (NO_x) generated under the provisions of §101.29 of this title used for the purposes of this chapter become subject to the limitations and provisions of this section. For the purposes of this section, the term "RC" refers to an ERC, MERC, DERC, or MDERC whichever is applicable.

(b) Reduction credits (RCs) shall be generated as follows.

(1) For sources not subject to the emission specifications of §117.105 or §117.205 of this title, creditable RCs used to meet compliance with those sections shall be established in accordance with the following requirements:

(A) The source shall use emissions test data to establish the actual emissions baseline in accordance with the testing requirements of §117.209(b) of this title (relating to Initial Control Plan Procedures), or §117.111 or §117.211 of this title (relating to Initial Demonstration of Compliance), as applicable. The actual emissions baseline is defined as the actual annual emissions, in tons per year, from a source determined by use of data representative of actual operations in 1990 or later, assuming full compliance with all applicable state and federal rules and regulations.

(B) If the source creating the RC has been shut down or irreversibly changed, the source shall use the best available data and good engineering practice to establish the actual emissions baseline.

(2) For sources subject to the emission specifications of §117.105 or §117.205 of this title, creditable RCs shall be calculated using the following equations:

$$\text{ERCs (tons per year)} = \sum_{j=1}^{N} \left[H_j \times (R_{Aj} - R_{Bj}) \times \frac{365}{2000} \right]$$

$$\text{DERCs (tons)} = \sum_{j=1}^{N} \left[H_j \times (R_{Aj} - R_{Bj}) \times \frac{d}{2000} \right]$$

or

Where:

j = each emission unit subject to this section generating RCs

N = the total number of emission units subject to this section generating RCs

H_j = actual daily heat input, in million British thermal units (MMBtu) per day, as calculated according to §117.223(b)(1) of this title, or for units that have been shutdown prior to June 9, 1993, as calculated according to §117.223(g)(3) of this title; except that the term may not include one standard deviation of the average daily heat input for the period in either calculation.

R_{Aj} = (A) For ERCs:

the lowest of

(i) any applicable federally enforceable emission limitation;

(ii) the reasonably available control technology (RACT) limit of §117.105 or §117.205(b)-(d) of this title; or

(iii) the actual emission rate as of June 9, 1993, in pound (lb)/MMBtu, that apply to emission unit *j* in the absence of trading.

For units that have been shut down prior to June 9, 1993, the actual emission rate shall be considered to be the average annual emission rate occurring over the period used to define the unit's baseline heat input, H_j.

(B) For DERCs:

the lower of:

(i) any enforceable emission limitation applicable during the generation period; or

(ii) the baseline emission rate defined in §101.29(a)(7) of this title (relating to Emissions Banking), in lb/MMBtu.

R_{Bj} = (A) For ERCs:

the enforceable emission rate, in lb/MMBtu, for unit *j* established in the registration under subsection (e) of this section;

(B) For DERCs:

the average emission rate, in lb/MMBtu, for unit *j* during the generation period

d = the number of days in the generation period

(3) RCs from shutdown units may be generated only by units participating in a source cap in accordance with §117.223 of this title.

(4) For units participating in a source cap in accordance with §117.223 of this title, creditable RCs may be generated only under the following conditions:

(A) The source cap allowable must be reduced by the amount of any creditable ERCs claimed for the unit or units, and

(B) the actual historical average of the daily heat input for the unit or units may not include one standard deviation of the actual average daily heat input for the period for which creditable reductions are claimed.

(c) Reduction credits shall be used as follows.

(1) An owner or operator complying with §117.223 of this title may reduce the amount of emission reductions otherwise required by complying with the following equations instead of the equations in §117.223(b)(1) and (2) of this title.

ERCs or MERCS:

$$\text{New 30-day rolling average emission limit (lb/day)} = \sum_{i=1}^{N} \left[(H_i \times R_i) + \left(RC_i \times \frac{2000}{365} \right) \right]$$

or

DERCs or MDERCS:

$$\text{New 30-day rolling average emission limit (lb/day)} = \sum_{i=1}^{N} \left[(H_i \times R_i) + \left(\frac{RC_i \times 2000}{d} \right) \right]$$

Where:

R_i, in lb/MMBtu, is defined as in §117.223(b)(1) of this title

i = each emission unit in the source cap

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

H_i = actual daily heat input, in MMBtu per day, as calculated according to §117.223(b)(1) of this title

RC_i = RC used for each unit, in tons per year (for ERCs or MERCs) or tons (for DERCs), generated in accordance with subsection (b) of this section. If RC_i is from a unit not subject to the emission specifications of §117.105 or §117.205 of this title, this term becomes Rc_i/F, where F is the offset ratio for the ozone nonattainment area where the unit is located (e.g. 1.2 for Beaumont/Port Arthur and 1.3 for Houston/Galveston).

d = the number of days in the use period

and

ERCs or MERCs:

$$\text{New maximum daily emission limit (lb/day)} = \sum_{i=1}^{N}\left[(H_{Mi} \times R_i) + \left(RC_i \times \frac{2000}{365}\right)\right]$$

or

DERCs or MDERCs:

$$\text{New maximum daily emission limit (lb/day)} = \sum_{i=1}^{N}\left[(H_{Mi} \times R_i) + \left(\frac{RC_i \times 2000}{d}\right)\right]$$

Where:

i and N are defined as in the first equation in this paragraph

R_i, in lb/MMBtu, is defined as in §117.223(b)(1) of this title

H_{Mi} = the maximum daily heat input, in MMBtu/day, as defined in §117.223(b)(2) of this title.

d = the number of days in the use period

(2) An owner or operator complying with §117.105, §117.107, §117.205, or §117.207 of this title may reduce the amount of emission reduction otherwise required by those sections for a unit or units at a major source by complying with individual unit emission limits calculated from the following equation:

ERCs or MERCs:

$$\text{New emission limit for unit i (lb/MMBtu)} = R_{Ai} + \left(\frac{RC_i}{H_{Mi}} \times \frac{2000}{365} \right)$$

or

DERCs or MDERCs:

$$\text{New emission limit for unit i (lb/MMBtu)} = R_{Ai} + \left(\frac{RC_i}{H_{Mi}} \times \frac{2000}{d} \right)$$

Where:

i = each emission unit subject to this section

N = the total number of emission units subject to this section

R_{Ai} = the lowest of any applicable federally enforceable emission limitation, the RACT limit of §117.105 or §117.205(b)-(d) of this title, or the actual emission rate as of June 9, 1993, in lb/MMBtu, that apply to emission unit *i* in the absence of trading. For units that have been shut down prior to June 9, 1993, the actual emission rate shall be considered to be the average annual emission rate occurring over the period used to define the unit's baseline heat input period in §117.223(g)(3) of this title.

d = the number of days in the use period

and

H_{Mi} and RC_i are defined as in paragraph (1) of this subsection.

The appropriate compliance averaging period specified in §117.105, §117.107, §117.205, or §117.207 of this title shall be assigned to unit *i* using a RC in accordance with the provisions of this paragraph.

(3) RCs from shutdown units may be used only by units participating in a source cap in accordance with §117.223 of this title.

(d) Any lower NO_x emission specification established by rule or permit for the unit or units generating an ERC shall require the user of the ERC to obtain an approved new reduction credit or otherwise reduce emissions prior to the effective date of such rule or permit change. For units using an ERC in accordance with this section which are subject to new, more stringent rule or permit limitations, the owner or operator using the ERC shall submit a revised final control plan to the executive director in accordance with §117.117 or §117.217 of this title (relating to Revision of Final Control Plan) to revise the basis for compliance with the emission specifications of this chapter. The owner or operator using the ERC shall submit the revised final control plan as soon as practicable, but no later than 90 days prior to the effective date of the new, more stringent rule or permit limitations. In addition, the owner or operator of a unit generating the ERC shall submit a revised registration application to the executive director, in accordance with subsection (e)(1) of this section, within 90 days prior to the effective date of any new, more stringent rule or permit limitations affecting that unit. If a more stringent NO_x emission specification is established by rule or permit for the unit or units generating the ERC, the value of the ERC shall be recalculated as follows:

ERCs:

$$\begin{array}{c}\text{Recalculated ERC}\\ \text{(tons per year)}\end{array} = \sum_{j=1}^{N} \left[H_j \times \left(R_{Bj} - R_{Aj-new}\right) \times \frac{365}{2000} \right]$$

Where:

j, N, H_j and R_{Bj} are defined as in subsection (b)(2) of this section

R_{aj-new} = the new NO_x emission specification for unit j, in lb/MMBtu

If the recalculated ERC is of zero or negative value, the ERC is determined to be of zero value.

(e) The RC program established by this section shall be administered as follows:

(1) For emission units subject to the emission specifications of this chapter, which generate ERCs, MERCs, DERCs, or MDERCs and for which the owner or operator elects to comply with the individual emission specifications of §§117.105, 117.107, 117.205, or 117.207 of this title, the enforceable emission limit R_{Bj} shall be calculated using the maximum rated capacity.

(2) For emission units subject to the emission specifications of this chapter, which generate ERCs, MERCs, DERCs, or MDERCs, and for which the owner or operator elects to achieve compliance using §117.223 of this title, the enforceable emission limit R_{Bj} shall be substituted for R_j in the source cap allowable mass emission rate equations of §117.223(b)(1) and (2) of this title, and those allowable rates shall be the enforceable limits for those sources.

(f) Stationary source emission reductions which were relied upon in the attainment demonstration modeling inventory for September 10, 1993 may not be used for generating emission reduction credits to comply with the lean-burn engine NO_x specification of §117.205(e) of this title. The modified requirements of this subsection are necessary for an owner or operator to use the trading requirements of this section to achieve compliance with the NO_x specification of §117.205(e) of this title. The modifications to this section are as follows:

(1) in §117.570(b)(1)(A) of this title, 1993 replaces 1990;

(2) in §117.570(b)(2) of this title, in the definition of R_{Aj}, December 31, 1999, replaces June 9, 1993;

(3) in §117.570(c)(2) of this title, in the definition of R_{Ai}, December 31, 1999, replaces June 9, 1993; and

(4) in each instance, references to §§117.223(b)(1), 117.223(b)(2), and 117.223(g)(3) of this title are date-modified in accordance with §117.223(k) of this title.