The Texas Natural Resource Conservation Commission (commission) proposes 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 proposes these revisions to Chapter 117, concerning Control of Air Pollution from Nitrogen Compounds, and 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 would 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 proposes to: 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.

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 a 24% emission reduction, equal to 3% per year from 1999 to 2007. A proposed lean-burn engine NO_x rule for BPA would provide a substantial portion of these reductions, or 5.29 tons per day (tpd) of the total 20% Rate-of-Progress NO_x reductions of 16.79 tpd. 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 proposed revisions would also implement NO_x RACT requirements for lean-burn gas-fired engines in BPA.

The proposed lean-burn engine rulemaking represents "Phase I" of the state's NO_x rulemaking activities for the BPA attainment demonstration. Under this schedule, 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 24% Rate-of Progress 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. Beginning in Summer 1999, the state commits to develop additional NO_x rules as needed for attainment in BPA. These "Phase II" rules needed for attainment would be submitted to EPA by March 31, 2000.

EXPLANATION OF PROPOSED RULES

The proposed 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 proposed 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 proposed 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 proposed new §117.205(e) and the proposed revision to §117.205(g)(6), now renumbered (h)(6), add an emission specification for lean-burn gas-fired engines in BPA. The proposed 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. The proposed 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 proposed 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, would 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 proposed revision would clarify 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 is not proposing to bring units which fire comparable fuels into the NO_x

emission specifications at this time, since the development of any such measures appears to be more complex than a lean-burn engine NO_x rule. An evaluation of NO_x controls from BIFs in BPA will be made during the development of Phase II rules.

The proposed change to §117.207(f) updates a cross-reference. The proposed change to §117.208(d)(1), concerning Operating Requirements, would exempt 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. Since it is ineffective for NO_x control and the operation is challenging, the commission is proposing to eliminate the boiler trim requirement for wood-fired boilers.

The proposed change to §117.211(d), concerning Initial Demonstration of Compliance, would clarify 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.

In response to a suggestion from a representative of an affected source with six fuels fed to one unit, the proposed 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. 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 meters should be at least as accurate in determining the NO_x mass emission rate as fuel flow meters. In some cases, exhaust flow monitoring may be more cost-effective than fuel flow monitoring.

The proposed new §117.213(b)(2) states that subsection (b) does not require units currently exempt from the Chapter 117 NO_x emission specifications to monitor exhaust O_2. 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.

The proposed 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 proposed changes clarify, but do not lessen, existing requirements.

Other proposed changes would 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 proposed to be 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 proposed changes to §117.213(i) and (m) correct rule cross-references.

The proposed changes to §117.219(e)(2), concerning Notification, Recordkeeping, and Reporting Requirements, would 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 proposed to expand the reporting to include the proposed newly regulated category of lean-burn engine emissions. The proposed change to §117.219(f)(1) would add a recordkeeping requirement for exhaust flow monitoring, in case that option (as newly proposed) is used. The proposed revision to §117.219(f)(2) would require recordkeeping of maintenance of the engine emissions control system for components other than catalytic converters or air-fuel ratio controllers. This change is proposed to ensure that records of maintenance of lean-burn engine emissions control systems are kept and made available upon request. The proposed revision to §117.219(f)(5) updates a rule cross-reference.

The proposed changes to §117.223, concerning Source Cap, would establish new baseline dates for owners or operators who wish to use the source cap compliance option for compliance with the proposed new lean-burn engine NO_x emission specification in BPA. This change would prevent double counting of emission reductions identified for the BPA ozone attainment SIP being proposed concurrently with this rule proposal. The net real reduction in point source NO_x emissions (due to activity level changes, process changes, startups and shutdowns, and addition of control equipment) in BPA from January 1, 1990 to December 31, 1996, and the anticipated reductions resulting from the lean-burn engine NO_x specification are counted separately in the reduction calculations for the proposed SIP. If a pre-1997 emission baseline was used to establish a source cap to comply with the new lean-burn engine NO_x specification, the reductions would be counted in both items in the SIP, or twice.

The proposed 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 is proposing 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.

A proposed change to §117.570(b)(2), concerning Trading, corrects a drafting error in the definition of the heat input term "H_j" by adding "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. Section 117.570(b)(4) currently specifies that the standard deviation is not applicable to the generation of creditable reductions, but since that paragraph pertains only to trading under a source cap, the clarification needs to be added more generally in §117.570(b)(2). Also in §117.570(b)(2), a proposed 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 proposed change simplifies the definition without changing its meaning. In addition, the equations in §117.570(c)(1), (c)(2), and (d) are being republished to correct printing errors in the version of the rule filed with the Secretary of State on December 3, 1997. This version of the adopted rule inadvertently contains the bold and bracket markings of the proposal.

Other proposed changes to §117.570 would establish new baseline dates for owners or operators who wish to use the trading compliance option for compliance with the proposed new lean-burn engine NO_x emission specification in BPA. The point source NO_x reductions that have occurred in BPA between November 1, 1990, and December 31, 1996, and the reductions that would result from the proposed lean-burn engine NO_x specification are counted separately in the reduction calculations for the BPA ozone attainment SIP being proposed concurrently with this rule proposal. The proposed change would prevent double counting of emission reductions in this SIP.

FISCAL NOTE

Randy Hamilton, Technical Specialist with Strategic Environmental Analysis and Assessment, has determined that for the first five-year period the proposed amendments are in effect, there will be no significant fiscal implications for state government or units of local government as a result of administration or enforcement of the amendments. The proposed lean-burn engine NO_x RACT rules in BPA will affect approximately eight major sources in the area. Enforcement of the proposed rules will require periodic inspection to verify compliance. It is anticipated that the Field Operations Division inspectors will inspect facilities for compliance with the proposed amended sections when conducting their routine inspections. It is also anticipated that enforcement of the proposed amended sections will not have a significant fiscal impact on the commission, other state agencies or units of local government. The other proposed changes, which clarify requirements or increase flexibility, will not appreciably change the inspection or compliance verification procedures of the commission, nor affect other state or local governments.

COST NOTE

Mr. Hamilton estimates the costs to persons required to comply with the proposed amended sections as follows. The proposal applies emission specifications to certain lean-burn gas-fired engines in BPA. An analysis of the 1994 initial control plans required by Chapter 117 and the 1993, 1996, and 1997 emissions inventory data submitted by sources in the area indicates that the proposed rule would require five major NO_x sources to reduce NO_x emissions from a total of 27 lean-burn engines. These sources consist of three natural gas transmission company pipeline compressor stations, one chemical plant, and one refinery. If there are any additional lean-burn engines required to reduce emissions, not identified by the emissions data analysis, it is anticipated that their compliance costs would be similar to the analysis which follows. The 27 natural gas-fired engines may be further characterized as large-bore and low-speed. The average NO_x emission reduction required to comply with the proposed NO_x limit is about 70%. This calculation is based on test results for these engines, submitted to the commission in 1994 with the Chapter 117 initial control plans. The types of modification that could be applied to meet the proposed limits include low-emission combustion retrofit (LEC), selective catalytic reduction, and replacement with electric motors. For purposes of this fiscal note, it will be assumed that LEC will be used, since it is the least expensive of these options. The cost estimation methodology used by EPA in their Alternative Control Techniques (ACT) document, "NO_x Emissions from Stationary Reciprocating Internal Combustion Engines," EPA-453/R-93-032, July 1993, is used with current capital equipment and maintenance costs estimates for LEC retrofit. The ACT applies a set of generic cost factors to a single manufacturer's 1992 retrofit hardware prices to develop estimates of total costs. Commission staff obtained updated LEC retrofit hardware and maintenance cost information from the engine original equipment manufacturers (OEM). The updated estimates include revised hardware and installation cost data from the single manufacturer who supplied data for the ACT. Local vendors also supplied some of the maintenance and emission test cost estimates. The current OEM costs are significantly lower than the 1992 ACT. The reduction in cost reflects the market's response to lean-burn engine retrofit requirements set by numerous states' NO_x RACT rules since 1992. Technical innovation and competition among vendors, including non-OEMs, have occurred since 1992.

Based on the OEM estimates, the total hardware costs for individual engines range from $150,000 for a 330 hp engine to $285,000 for one model of 2,000 hp engine. The total capital costs, reflecting tax, freight, direct installation cost, indirect installation cost, and contingency, are estimated using ACT factors, equal to 1.73 x hardware cost. Using this equation, the total capital costs for individual engines would range from $260,000 for the 330 hp engines to $493,000 for one model of 2,000 hp engine. The total annualized costs, reflecting annual operating and amortized capital costs, are also estimated using ACT factors, but with the following adjustments. The ACT identifies additional spark plug and precombustion chamber fuel check valve replacement as LEC retrofit items which result in increased maintenance cost, but applies a factored cost to estimate annual additional maintenance cost. Based on information provided by the OEMs and a local control equipment vendor, the specific cost for these items is estimated at $2,500 per year per engine, based on $22 per plug, $150 per check valve, and $50/hr labor cost. This cost is substituted for the ACT maintenance cost factor of 10% of total capital cost. According to the OEMs, LEC reduces engine misfire, which is beneficial to valve liner and piston ring life, and also reduces engine oil and jacket water operating temperatures. Maintenance cost reductions resulting from these improvements are not easily quantified, and are not specifically included in the maintenance cost estimate. The ACT operating cost factor for taxes, insurance, and administrative costs are adjusted by removing the property tax component, to account for Proposition 2, a state property tax exemption for capital investments made to comply with environmental law. The ACT's overhead cost factor, equal to 60% of maintenance cost, a fuel savings based on a 1% fuel efficiency credit, and a 15-year, 7% capital recovery factor of 0.1098 are used. The ACT's test costs are adjusted to more specifically reflect the proposed test requirements, which would extend the test requirements for rich-burn engines to the lean-burn engines. In order to ensure initial and continued emissions compliance, any owner or operator of engines subject to the emission limits would be required to perform a compliance test before the initial compliance date, and every two years following. The compliance test costs are estimated at $2,500 per engine for the first engine, and $750 for each additional engine at a site. The rule also requires emission checks at least quarterly with stain tubes or portable analyzers. The emission check cost is estimated at $400 per engine. The total emission test costs are estimated at $2,650 annually per engine. The rule requires record keeping of maintenance performed on the emission control equipment. The additional record keeping costs are estimated as negligible, since the rule does not specify explicit contents, and maintenance records are already being kept for these engines. Based on the identified cost items, the total annualized cost for individual engines would range from $42,000 for the 330 hp engines to $71,000 for one model of the 2,000 hp engines. The table titled "Annual Cost Calculations" indicates calculations used to determine total annual costs. Using these figures, for each year of the first five years that the rule would be in effect, the probable economic cost to persons required to reduce emissions to comply with the rule would range between $112,000 for a source with two 2,000 hp engines and $632,000 for a source with thirteen engines.

The emissions data submitted by BPA sources also indicates that in addition to the 27 engines required to reduce emissions, there are eleven lean-burn engines which would be subject to the proposed emission limits, but appear to presently comply with those limits. For the three major sources with these engines, the cost of complying with the proposed rule would occur from the emission test requirements. The requirements and $2,650 per engine test costs would be the same as those identified for the engines required to reduce emissions. For each year of the first five years that the rule would be in effect, the probable economic cost to persons required to comply with these test requirements would range between $5,300 for a facility with two engines subject to the proposed emission limits, and $13,250, for a facility with five engines.

This proposed rulemaking also applies to other owners or operators of existing major sources of NO_x in BPA, DFW, and HGA. The changes would eliminate the requirement to operate wood-fired boilers with flue gas sensor trim of combustion air, a requirement which appears to apply to two large Texas companies. Another proposed amendment would add the option to monitor exhaust flow instead of fuel flow, an option which may be attractive to owners of units with multiple fuels fired in a single unit. Other proposed changes clarify certain commission rules applicable to existing major stationary sources of NO_x emissions. These changes do not require additional control equipment or measures. The eliminated requirement and added flexibility will result in cost savings; no additional costs are anticipated with the proposed clarification of requirements.

ANNUAL COST CALCULATIONS

Company Type	MF	Model	HP	HW$	TCC	Maint	Overhead	Fuel	T,I,A	Test	Capital Recovery	Total Annual Cost
Chemical Plt. A	CL	HRA32	330	150,000	259,500	2500	1500	(904)	7785	2650	28,493	42,024
Chemical Plt. A	CL	HRA32	330	150,000	259,500	2500	1500	(904)	7785	2650	28,493	42,024
Chemical Plt. A	CL	HRA5	550	190,000	328,700	2500	1500	(1370)	9861	2650	36,091	51,232
Chemical Plt. A	CL	HRA5	550	190,000	328,700	2500	1500	(1370)	9861	2650	36,091	51,232
Chemical Plt. A	CL	HRA5	550	190,000	328,700	2500	1500	(1370)	9861	2650	36,091	51,232
Chemical Plt. A	CL	HRA5	550	190,000	328,700	2500	1500	(1370)	9861	2650	36,091	51,232
Chemical Plt. A	CL	HRA5	550	190,000	328,700	2500	1500	(1370)	9861	2650	36,091	51,232
Chemical Plt. A	CL	HRA5T	880	150,000	259,500	2500	1500	(2150)	7785	2650	28,493	40,778
Chemical Plt. A	CL	HRA5T	880	150,000	259,500	2500	1500	(2150)	7785	2650	28,493	40,778
Chemical Plt. A	CL	HRA5T	880	150,000	259,500	2500	1500	(2150)	7785	2650	28,493	40,778
Chemical Plt. A	CL	HRA5T	880	150,000	259,500	2500	1500	(2150)	7785	2650	28,493	40,778
Chemical Plt. A	CL	HRA8	880	250,000	432,500	2500	1500	(2960)	12975	2650	47,489	64,154
Chemical Plt. A	CL	HRA8	880	250,000	432,500	2500	1500	(2960)	12975	2650	47,489	64,154
Gas Trans. Sta. B	CB	GMWA8	2000	210,000	363,300	2500	1500	(4930)	10899	2650	39,890	52,509
Gas Trans. Sta. B	CB	GMWA8	2000	210,000	363,300	2500	1500	(4930)	10899	2650	39,890	52,509
Gas Trans. Sta. B	CB	GMWA8	2000	210,000	363,300	2500	1500	(4930)	10899	2650	39,890	52,509
Gas Trans. Sta. C	CB	GMW10	2500	245,000	423,850	2500	1500	(6160)	12819	2650	46,919	60,228
Gas Trans. Sta. C	CB	GMW10	2500	245,000	423,850	2500	1500	(6160)	12819	2650	46,919	60,228
Gas Trans. Sta. C	CB	GMW10	2500	245,000	423,850	2500	1500	(6160)	12819	2650	46,919	60,228
Gas Trans. Sta. C	CB	GMW10	2500	245,000	423,850	2500	1500	(6160)	12819	2650	46,919	60,228
Gas Trans. Sta. C	CB	GMW10	2500	247,000	427,310	2500	1500	(6160)	12819	2650	46,919	60,228
Gas Trans. Sta. C	CB	GMW10	2500	247,000	427,310	2500	1500	(6160)	12819	2650	46,919	60,228
Gas Trans. Sta. D	IR	412KVS	2000	285,000	493,050	2500	1500	(4930)	14792	2650	54,137	70,648
Gas Trans. Sta. D	IR	412KVS	2000	285,000	493,050	2500	1500	(4930)	14792	2650	54,137	70,648
Gas Trans. Sta. D	IR	412KVS	2000	285,000	493,050	2500	1500	(4930)	14792	2650	54,137	70,648
Refinery E	IR	38KVR	2750	234,000	404,820	2500	1500	(8960)	12145	2650	44,449	55,851
Refinery E	IR	38KVR	2750	234,000	404,820	2500	1500	(8960)	12145	2650	44,449	55,851

PUBLIC BENEFIT

Mr. Hamilton also has determined that for each year of the first five years the sections as proposed are in effect, the anticipated public benefit will be reductions of NO_x emissions and ambient ozone levels. BPA does not currently meet the federal health standard for ozone.

SMALL BUSINESS ANALYSIS

The proposed amendments generally do not apply to small businesses, since most major sources of NO_x are not small businesses. The commission has been unable to identify any major sources of NO_x in BPA with lean-burn engines which are small businesses.

DRAFT REGULATORY IMPACT ANALYSIS

The commission has reviewed the proposed rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and has determined that the rulemaking 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 proposed 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 proposed new 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 proposed 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 proposed rules, which reduce ambient NO_x and ozone in BPA, will be submitted to EPA—upon adoption—as one of several measures of the required new attainment demonstration. These rules will 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 proposed 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 proposed 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 proposed 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 proposed changes are not proposed solely under the general rulemaking authority of the commission but are proposed to comply with the requirements of federal regulations.

Other proposed 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 proposed amendments may result in positive fiscal implications to the regulated community. Therefore, these proposed 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. The commission invites public comment on the draft regulatory impact analysis.

TAKINGS IMPACT ASSESSMENT

The commission has prepared a takings impact assessment for these sections under Texas Government Code, §2007.043. The following is a summary of that assessment. The specific purposes of these amendments are: to develop a new attainment demonstration SIP for the ozone NAAQS for 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. If adopted, certain major sources located in BPA will be required to install new emission control equipment, and implement new operating, reporting, and recordkeeping requirements. Installation of the necessary control equipment could conceivably place a burden on private, real property. 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 proposed 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 proposed changes would 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 proposed rules are consistent with the applicable CMP policy because they are consistent with Title 40. Title 40, Part 51, sets out requirements for states to prepare, adopt, and submit implementation plans for the attainment of the NAAQS. The adopted rules would be submitted to EPA under these requirements. Interested persons may submit comments on the consistency of the proposed rules with the CMP during the public comment period.

PUBLIC HEARING

A public hearing on the proposed BPA SIP and accompanying rule revisions will be held in Beaumont on August 9, 1999, at 5:30 p.m. at the John Gray Institute, located at 855 Florida Avenue. Individuals may present oral statements when called upon in order of registration. Open discussion will not occur during the hearing; however, agency staff members will be available to discuss the proposal 30 minutes prior to each hearing and will answer questions before and after the hearing.

SUBMITTAL OF COMMENTS

Written comments may be mailed to Casey Vise, MC 205, Office of Environmental Policy, Analysis, and Assessment, Texas Natural Resource Conservation Commission, P.O. Box 13087, Austin, Texas 78711-3087, or faxed to (512) 239-4808. All comments should reference Rule Log Number 99020-117-AI. Comments must be received by 5:00 p.m., August 16, 1999. For further information or questions concerning this proposal, please contact Randy Hamilton of the SIP Development Team at (512) 239-1512.

Persons with disabilities who have special communication or other accommodation needs who are planning to attend the hearings should contact the agency at (512) 239-4900. Requests should be made as far in advance as possible.

STATUTORY AUTHORITY

The amendments are proposed 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.

The proposed amendments implement Texas Health and Safety Code, §382.012.

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) - (36) (No change.)

<u>(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.</u>

<u>(38)</u> [(37)] **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) [(38)] **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) [(39)] **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

§117.205. 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) [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) [Btu] heat input, shall be limited to that rate for the purposes of this subchapter; and

(B) (No change.)

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

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

(B) (No change.)

(3) (No change.)

(b) [For boilers and process heaters which operate with continuous emission monitors (CEMS) or predictive emissions monitors (PEMS) in accordance with §117.213 of this title (relating to Continuous Demonstration of Compliance), the emission limits shall apply as the mass of NO_x emitted per unit of energy input (pound NO_x per MMBtu), on a rolling 30-day average period, or as the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average. For boilers and process heaters which do not operate with 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. The mass of NO_x emitted per hour shall be calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in pound NO_x per MMBtu.] For each 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) - (4) (No change.)

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

(6) for any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, a multiplier of 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) - (d) (No change.)

(e) No person shall allow the discharge into the atmosphere from any gas-fired, lean-burn, stationary, reciprocating internal combustion engine, emissions in excess of a block one-hour average of 3.0 g NO_x/hp-hr and 3.0 g CO/hp-hr for engines which are rated 300 hp or greater and located in the Beaumont/Port Arthur ozone nonattainment area.

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

(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) [(f)] 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) [(g)] Units exempted from the emissions specifications of this section include the following:

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

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

(3) boilers and industrial furnaces which were [are] 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) - (c) (No change.)

(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 [average] of the appropriate gaseous and liquid fuel emission specifications of §117.205 of this title [(relating to Emission Specifications)] 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 [average] of the appropriate emission specifications of §117.205 of this title [(relating to Emission Specifications)] 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) [§117.205(g)] of this title are also exempt under this section and shall not be included in the plant-wide emission limit, except as follows. The owner or operator of exempted units as defined in §117.205(h) [§117.205(g)] of this title may opt to include one or more of an entire equipment class of exempted units into the alternative plant-wide emission specifications.

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

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

§117.207(f) OPT-IN UNITS

Equipment Class/Description	Emission Specification
fluid catalytic cracking unit carbon monoxide (CO) boilers	50% NO_x reduction across the inlet of the CO boiler to the outlet of the CO boiler, with the outlet concentration in ppmv converted into lb NO_x/MMBtu of heat input
lean-burn, gas-fired, stationary, reciprocating internal combustion engines rated 150 hp or greater	5.0 grams NO_x/hp-hr under all operating conditions
boilers, steam generators, or process heaters with a maximum rated capacity (MRC): 40 MMBtu/hr $\leq$ MRC $<$ 100 MMBtu/hr	the emission specifications in §117.205(a) of this title for the applicable type of unit
stationary gas turbines with a MW rating: 1.0 MW $\leq$ MW rating $<$ 10.0 MW	42 ppmv NO_x at 15% O_2, dry basis
boilers and industrial furnaces which 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	the appropriate emission limitation in §117.205(b) of this title

(g) - (h) (No change.)

§117.208. Operating Requirements.

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

(d) All units subject to the emission limitations of <u>§§117.205, 117.207, or 117.223</u> [§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) - (7) (No change.)

§117.209. Initial Control Plan Procedures.

(a) (No change.)

(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 [Btu] per hour (MMBtu/hr), except for low annual capacity factor boilers and process heaters as defined in §117.10 of this title (relating to Definitions);

(2) boilers and industrial furnaces with a maximum rated capacity greater than or equal to 40 MMBtu/hr which were [are] regulated as existing facilities by EPA [the United States Environmental Protection Agency (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) - (6) (No change.)

(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 [horsepower (hp)] or

greater, or located in the Beaumont/Port Arthur ozone nonattainment area and rated 300 hp or greater; all stationary gas turbines with an MW [a megawatt (MW)] rating of greater than or equal to 1.0 MW; to include the maximum rated capacity, anticipated annual capacity factor, the facility identification numbers and emission point numbers as submitted to the Area and Mobile Emissions Assessment and Industrial Emissions Assessment Sections [Emissions Inventory Section] of the commission [Texas Natural Resource Conservation Commission (TNRCC)], and the emission point numbers as listed on the Maximum Allowable Emissions Rate Table of any applicable commission [TNRCC] permit for each unit;

(2) - (11) (No change.)

§117.211. Initial Demonstration of Compliance.

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

(d) Early testing conducted before March 21, 1999 [the effective date of this rule as revised] 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) (No change.)

(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 <u>a</u> [an] NO_x emission limit in pound per <u>million British thermal units (MMBtu)</u> [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) - (3) (No change.)

(4) For units complying with §117.223 of this title [(relating to Source Cap)], 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) (No change.)

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

(A) (No change.)

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

(C) - (D) (No change.)

(3) - (8) (No change.)

§117.213. Continuous Demonstration of Compliance.

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

(1) The units are the following [units,]:

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

(i) [(A)] boilers;

(ii) [(B)] process heaters;

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

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

(B) [(2)] stationary, reciprocating internal combustion engines not exempt by §117.203(6) or (8) of this title (relating to Exemptions);

(C) [(3)] stationary gas turbines with a megawatt (MW) [MW] rating greater than or equal to 1.0 MW operated more than 850 hours per year; and

(D) [(4)] 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 [oxygen (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) [(1)] boilers with a rated heat input greater than or equal to 100 MMBtu/hr; and

(B) [(2)] process heaters with a rated heat input:

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

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

(2) Units listed in §117.205(h)(3)-(5) of this title (relating to Emission Specifications) are not subject to this subsection.

(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 [Nitrogen oxides (NO_x)] monitors.

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

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

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

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

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

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

(B) [gas turbines or other units which are affected] units [and are] subject to the NO_x CEMS [continuous emissions monitoring] requirements of [in accordance with] 40 CFR 75.

(d) (No change.)

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

(1) (No change.)

(2) Monitor diluent, either O_2 or carbon dioxide (CO_2) [CO_2].

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

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

(1) (No change.)

(2) Monitor diluent, either O_2 or CO_2:

(A) using a CEMS

(i) (No change.)

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

(B) (No change.)

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

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

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

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

(i) (No change.)

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

(iii) (No change.)

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

(g) - (h) (No change.)

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

(j) - (l) (No change.)

(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) [§117.205(g)(2)] of this title (relating to Definitions), shall notify the executive director within seven days if the Btu/yr or hour-per-year limit specified in §117.10 of this title, as appropriate, is exceeded.

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

§117.219. 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 [United States Environmental Protection Agency (EPA)], and any local air pollution control agency having jurisdiction upon request. These records shall include, but are not limited to: type of fuel burned; quantity of each type of fuel burned; and the date, time, and duration of the procedure.

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

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system under §117.213 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations of this division (relating to 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) [NO_x] emissions exceed the rolling 30-day average or the maximum daily NO_x cap.

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

(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) (No change.)

(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 [catalytic converter, or air-fuel ratio controller], 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 <u>(or stack exhaust flow)</u> for units complying with an emission limit enforced on a block one-hour average; and

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

(i) pound per million <u>British thermal units (Btu)</u> [Btu] heat input; and

(ii) (No change.)

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

(A) (No change.)

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

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

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

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

(6) - (8) (No change.)

§117.223. Source Cap.

(a) - (f) (No change.)

(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) - (2) (No change.)

(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) - (5) (No change.)

(6) Shutdowns which occurred before January 1, 1997, 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) - (j) (No change.)

(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) December 31, 1996, replaces November 15, 1990, throughout;

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

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

(3) 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 dates in paragraphs (1) and (2) of this subsection.

SUBCHAPTER D : ADMINISTRATIVE PROVISIONS

§117.520, §117.570

§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 [or Houston/Galveston] 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 [November 15, 1999 (final compliance date)]. 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 a plan for compliance in accordance with §117.209 of this title (relating to Initial Control Plan Procedures) according to the following schedule:]

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

[(B) for major sources of NO_x which have no units subject to emission specifications under this chapter, submit an initial control plan for all such units no later than September 1, 1994; 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 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), [submit] 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) [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) [§117.217(c) or (d)] of this title (relating to Notification, Recordkeeping, and Reporting Requirements [Revision of Final Control Plan]), 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) (No change.)

(2) submit to the executive director:

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

(D) the first semiannual report required by §117.219(d) or (e) [§117.217(c) or (d)] 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) (No change.)

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

(1) (No change.)

(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:

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

or

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

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}	=	the lowest of any applicable federally enforceable emission limitation, the reasonably available control technology (RACT) limit of §117.105 or §117.205(b)-(d) of this title, or 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.

R_{Bj} = the enforceable emission rate, in lb/MMBtu, for unit j established in the registration under subsection (e) of this section.

d = the number of days in the generation period

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

(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) (No change.)

(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:

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

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) (No change.)

(f) Stationary source emission reductions which occurred before January 1, 1997, 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, 1997 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.