The Texas Commission on Environmental Quality (TCEQ, agency, or commission) proposes new §§117.200, 117.203, 117.205, 117.230, 117.235, 117.240, 117.245, 117.252, 117.1100, 117.1103, 117.1105, 117.1120, 117.1140, 117.1145, 117.1152, 117.3124, 117.9010, and 117.9110; and amendments to §§117.10, 117.310, 117.340, 117.410, 117.440, 117.2010, 117.2035, 117.2110, 117.2135, 117.3000, 117.3103, 117.3110, 117.3120, 117.3145, 117.9030, 117.9300, 117.9320, and 117.9800. If adopted, these rules would be submitted to the United States Environmental Protection Agency (EPA) as a state implementation plan (SIP) revision.

Background and Summary of the Factual Basis for the Proposed Rules

Reasonably Available Control Technology (RACT) Rules for Major Sources

The 1990 federal Clean Air Act (FCAA) Amendments (42 United States Code (USC), §§7401 et seq.) require the United States Environmental Protection Agency (EPA) to establish primary National Ambient Air Quality Standards (NAAQS) that protect public health and to designate areas as either in attainment or nonattainment with the NAAQS, or as unclassifiable. States are primarily responsible for ensuring attainment and maintenance of the NAAQS once established by the EPA. Each state is required to submit a SIP to the EPA that provides for attainment and maintenance of the NAAQS.

Nonattainment areas classified as moderate and above are required to meet the mandates of the FCAA under §172(c)(1) and §182(b)(2) and (f). FCAA, §172(c)(1) requires that the SIP incorporate all reasonably available control measures, including RACT, as expeditiously as practicable for major sources of volatile organic compounds (VOC) and for all VOC sources covered by EPA-issued control techniques guidelines. FCAA, §182(f) requires the state to submit a SIP revision that implements RACT for all major sources of nitrogen oxides (NO_X).

The EPA defines RACT as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility (44 *Federal Register* (FR) 53761, September 17, 1979). RACT requirements for moderate and higher classification nonattainment areas are included in the FCAA to assure that significant source categories at major sources of ozone precursor emissions are controlled to a reasonable extent, but not necessarily to best available control technology (BACT) levels expected of new sources or to maximum achievable control technology (MACT) levels required for major sources of hazardous air pollutants. Although the FCAA requires the state to implement RACT EPA guidance provides states with the flexibility to determine the most technologically and economically feasible RACT requirements for a nonattainment area. A major source is 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 specific amount of NO_x emissions based on the area's nonattainment classification.

The proposed rulemaking would implement RACT requirements for major sources of NO_x in the Dallas-Fort Worth eight-hour ozone nonattainment area (DFW) and in Bexar County. The TCEQ evaluated the existing major sources in the DFW area and in Bexar County, and considered state and federal rules to determine what rules would be necessary to fulfill FCAA RACT requirements. The proposed rules are necessary so that all major NO_x emission sources in the DFW area and Bexar County are subject to rules in 30 Texas Administrative Code (TAC) Chapter 117, or other federally enforceable measures, that meet or exceed the applicable RACT requirements. Additional NO_x controls on major sources were determined to be either not economically feasible or not technologically feasible, as documented in the concurrently proposed SIP revisions for Bexar County and the DFW and Bexar County areas (SIP project numbers 2023-107-SIP-NR and 2023-132-SIP-NR, respectively).

Bexar County RACT

Bexar County is currently classified as moderate nonattainment for the 2015 eight-hour ozone NAAQS (87 FR 60897, October 7, 2022). Bexar County must attain the 2015 eight-hour ozone NAAQS by September 24, 2024 (87 FR 60897). The SIP revision to address FCAA requirements, including RACT, was due to the EPA by January 1, 2023, but the commission was unable to complete the review prior to the submission deadline.

In Bexar County, a major source is any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit at least 100 tons per year (tpy) of NO_X. To identify all major sources of NO_X emissions in Bexar County, the TCEQ reviewed the point source emissions inventory and Title V databases. All sources in the Title V database that were listed as a major source for NO_X emissions were included in the RACT analysis. Since the point source emissions inventory database reports actual emissions rather than potential to emit, the TCEQ reviewed sources that reported actual emissions as low as 50 tpy of NO_X to account for the difference between actual and potential emissions. Sites from the emissions inventory database with emissions of 50 tpy or more of NO_X that were not identified in the Title V database and could not be verified as minor sources by other means are also included in the RACT analysis. The existing Chapter 117 rules, rules in other states, and federal rules were considered to evaluate what rules would be necessary to fulfill RACT requirements.

The proposed rulemaking implements RACT requirements for major sources of NO_X in Bexar County. The proposed provisions include emission standards, exemptions, monitoring, recordkeeping, reporting, and testing requirements that would apply to engines, turbines, boilers, and cement kilns at major sources of NO_X emissions in Bexar County. Affected sources would have to comply with these rules by January 1, 2025. The proposal includes new divisions or sections in 30 TAC Chapter 117, Subchapter B, Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Nonattainment Areas; Subchapter C, Combustion Control at Major Utility Electric Generation Sources in Ozone Nonattainment Areas; and Subchapter H, Administrative Provisions, Division 1, Compliance Schedule. In support of the new requirements, revisions are also proposed to Subchapter A, Definitions; Subchapter E, Multi-Region Combustion Control; and Subchapter H, Administrative Provisions, Division 2, Compliance Flexibility.

DFW RACT

The DFW area (Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, Tarrant, and Wise Counties) was reclassified as severe for the 2008 eight-hour ozone NAAQS (87 FR 60926, October 7, 2022). The DFW area must attain the 2008 eight-hour ozone NAAQS by July 20, 2027 (87 FR 60926). The SIP revision to address severe nonattainment area requirements is due to the EPA on May 7, 2024.

In the DFW 2008 severe ozone nonattainment area, a major source is any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit at least 25 tpy of NO_X. The TCEQ reviewed the point source emissions inventory and Title V databases to identify all major sources of NO_X emissions in the DFW area. All sources in the Title V database that were listed as a major source for NO_X emissions were included in the RACT analysis. Since the point source emissions inventory database reports actual emissions rather than potential to emit, the TCEQ reviewed sources that reported actual emissions as low as 10 tpy of NO_X to account for the difference between actual and potential emissions. Sites from the emissions inventory database with emissions of 10 tpy or more of NO_x that were not identified in the Title V database and could not be verified as minor sources by other means are also included in the RACT analysis.

The existing Chapter 117 rules were compared to rules in other states and federal rules to determine whether the existing rules continue to fulfill RACT requirements. Chapter 117 rules that are consistent with or more stringent than controls implemented in other nonattainment areas were determined to fulfill RACT requirements. Federally approved state rules and rule approval dates can be found in 40 Code of Federal Regulations (CFR) §52.2270(c), *EPA Approved Regulations in the Texas SIP*. Emission sources subject to the more stringent BACT or MACT requirements were determined to also fulfill RACT requirements.

The commission reviewed the emission sources in the DFW area and the applicable Chapter 117 rules to verify that all major emission sources in the DFW area are subject to requirements that meet or exceed the applicable RACT requirements, or that further emission controls on the sources were either not economically feasible or not technologically feasible. The current EPA-approved Chapter 117 rules continue to fulfill RACT requirements. Additional NO_x controls on major sources were determined to be either not economically feasible or not technologically feasible.

The proposed rule project implements RACT requirements for major sources of NO_x in the DFW area. The proposed rulemaking would revise the definitions in Chapter 117, Subchapter A and compliance schedules in Subchapter H, Division 1 to lower the major source threshold from 50 tpy NO_x to 25 tpy of NO_x. Because the DFW area was previously classified as serious nonattainment for the 2008 eight-hour ozone standard, sources that emit or have the potential to emit at least 50 tpy NO_X are already required to comply with Chapter 117 RACT rules. This proposed rulemaking would extend implementation of RACT to all major sources of NO_X that emit or have the potential to emit at least 25 tpy NO_X. The proposed rulemaking would require major sources of NO_X to comply with new emission limits, control requirements, or operating requirements as well as other associated rule provisions necessary to implement any required NO_X control measures, such as monitoring, testing, recordkeeping, reporting, and exemptions no later than November 7, 2025.

Rule Petition Revisions for the DFW and Houston-Galveston-Brazoria (HGB) Areas

On May 10, 2023, the commissioners directed the Executive Director to initiate a rulemaking to examine the issues raised in a rulemaking petition filed with the TCEQ on March 13, 2023, by Baker Botts LLP, on behalf of the Texas Industry Project under 30 TAC §20.15. As directed by the commission, the Executive Director reviewed the issues raised in the March 13, 2023, rulemaking petition. This proposed rulemaking would revise 30 TAC Chapter 117 for sources in the DFW and HGB areas to remove the requirements for certain engines to monitor NO_X emissions using continuous emissions monitoring systems (CEMS) or a predictive emissions monitoring system (PEMS), to adjust the applicable ammonia emission limit to be consistent with typical operation of diesel engines, and to remove the ammonia monitoring requirements for these engines. Although the Chapter 117 ammonia standards are not part of the SIP, both the NO_X and ammonia monitoring requirements are included as part of the SIP. Therefore, any rule changes would need to be submitted as part of the SIP.

The existing rules for major sources of NO_X in the DFW and HGB areas require the owner or operator of units that use a chemical reagent for reduction of NO_X emissions to install a CEMS or PEMS to monitor exhaust NO_X emissions (see §117.340(c)(1)(D) and §117.440(c)(1)(C)). The existing rules for major and minor sources of NO_x in the DFW and HGB areas require the owner or operator of units that use a chemical reagent for reduction of NO_x emissions (to comply with an ammonia emission specification and therefore) to monitor ammonia emissions from the unit using one of the ammonia monitoring procedures specified in §117.8130 (see §§117.340(d), 117.440(d), 117.2035(e)(2), and 117.2135(d)(2)). These monitoring requirements are used to verify that affected units meet the applicable NO_x and ammonia emission limits and provide additional assurance that NO_x and ammonia emission rates will not increase due to variation in the operation of the SCR systems.

Manufacturer-certified Tier 4 engines rely on selective catalytic reduction (SCR) with a chemical reagent (such as urea or ammonia) to meet the federal limits in 40 CFR Part 1039, Subpart B. These engines are not manufactured with pre-installed CEMS because they are designed, tested, and certified to ensure that NO_x emissions conform to federal Tier 4 standards during all normal operating conditions. The engine and emission control system are designed to minimize or exclude adjustable operating parameters and all adjustable parameters include restrictions, limits, stops, or other means of inhibiting adjustment to prevent adjusting parameters to settings outside the tested ranges. Tier 4 engines with SCR systems are designed to ensure the system operates within the certified parameters and equipped with an engine diagnostic system that issues a warning if the quality or quantity of the reductant does not meet the design specifications. Ensuring the proper operation of the emission control system also ensures that ammonia emissions remain low.

Given that the engine and emission control system cannot be manipulated by operators due to the certified engine design and considering the significant cost of installing and operating a CEMS and the logistics of installing a building for the monitoring system for a unit that may be moved from one location to another, the commission proposes that a CEMS or PEMS is not necessary under Chapter 117 to provide reasonable assurance of compliance with the applicable NO_X and ammonia emission specifications for stationary diesel engines subject to the requirements of 40 CFR Part 1039, Subpart B, and the commission proposes to exempt these engines from the CEMS and PEMS NO_X monitoring requirements and the ammonia monitoring requirements in Chapter 117.

The existing rules for major and minor sources of NO_X in the DFW and HGB areas require the owner or operator of units subject to an ammonia emission specification under Chapter 117 to demonstrate initial compliance with the applicable ammonia specification (see §§117.340(d), 117.440(d), 117.2035(e)(2), and 117.2135(d)(2)). Because these units would not be equipped and operating with a CEMS or PEMS, owners or operators of these affected units would be required to conduct a stack test according the one of the allowed test methods under existing §117.8000(c)(4). The commission is also proposing to require these engines to be equipped with an engine diagnostic system that measures the quantity and quality of reductant ensure proper operation of the SCR control system based on the requirements of existing 40 CFR Part 1039, Subpart B, §1039.110.

Existing Chapter 117 rules require that ammonia emissions must not exceed 10 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry, for all units that inject urea or ammonia into the exhaust stream for NO_X control. The commission proposes that correcting ammonia concentrations to the 3.0% O_2 level currently required is inappropriate for diesel engines that operate at significantly higher excess air in the exhaust stream and is proposing revisions to allow diesel engines to use the 15% O_2 correction consistent with the Chapter 117 standards for other equipment that also operates with higher O_2 in the exhaust gas (see §§117.310(c)(2), 117.410(c)(2), 117.2010(i)(2), 117.2110(h)(2)).

Demonstrating Noninterference Under FCAA §110(l)

The proposed changes are not expected adversely impact Texas's progress in attaining the eight-hour ozone NAAQS. These manufacturer-certified Tier 4 engines remain subject to the NOX and ammonia emission limits in Chapter. The engines are also required to comply with to NO_X monitoring and testing requirements and ammonia testing requirements that will provide for the accurate accounting of emissions and provide reasonable assurance of compliance with the applicable NO_X and ammonia emission specifications for these stationary diesel engines. The proposed requirement for the diagnostic system to alert the owner or operator when the reductant material quality is not within material concentration specifications as established by the SCR control system equipment manufacturer will also provide confidence that the NO_X emission controls are properly functioning. All of these requirements will ensure that no backsliding from the current SIP-approved requirements.

Section by Section Discussion

Subchapter A, Definitions

The commission proposes to revise the definition of applicable ozone nonattainment area in §117.10(2) to include the Bexar County ozone nonattainment area, which consists of Bexar County, and then re-letters the definitions for the subsequent areas as necessary to put the list in alphabetical order.

The proposal revises the definition of electric power generating system in §117.10(14) to include proposed new Subchapter C, Division 2 for Bexar County Ozone Nonattainment Area Utility Electric Generation Sources and to exclude Bexar County sources from existing rules for

Utility Electric Generation in East and Central Texas in Subchapter E, Division 1 after December 31, 2024. This change ensures that EGUs in Bexar County will remain in compliance with the existing rule until they are required to comply with the proposed new rule. Portions of the existing definition would be re-numbered as necessary to keep the list in alphabetical order.

The proposal revises the §117.10(29) definition of major source to include any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit at least 100 tpy of NO_x and is in the Bexar County ozone nonattainment area. The definition would also be revised to ensure that for the purposes of Chapter 117 Bexar County sources are only included in the major source definition contained in 40 Code of Federal Regulations §52.21 (as amended June 3, 1993, effective June 3, 1994) until December 31, 2024, when sources are required to comply with the proposed new rule. The proposal also revises the definition of major source in §117.10(29) to lower the major source threshold from 50 tpy to 25 tpy of NO_x for sources in the Dallas-Fort Worth eight-hour ozone nonattainment area. The change is necessary to account for the area's severe classification for the 2008 eight-hour ozone NAAQS. Major sources affected by the proposed rulemaking are required to comply all applicable Chapter 117 rules by November 7, 2025, as stated in proposed changes §117.9030. Minor sources that are currently subject to Chapter 117, Subchapter D, Division 2 remain subject to that division until they are required to comply with the major source rule in Chapter 117, Subchapter B, Division 4. This is necessary since engines at sources that emit or have the potential to emit more than 25 tpy NO_x but no more than 50 tpy NO_x will be transitioning from compliance with the minor source rule to compliance with the major source rule. The proposed compliance date was selected based on the RACT due date from the severe reclassification (87 FR 60931, October 7, 2022). Portions of the existing definition would be re-lettered as necessary to keep the list in alphabetical order.

The proposed rule would revise the §117.10(51) definition of unit to reflect the proposed new requirements for Bexar County. The proposed change adds that for the purposes of §117.205 and associated requirements, a unit is any stationary gas turbine (including any duct burner used in the turbine exhaust duct) or gas-fired lean-burn stationary reciprocating internal combustion engine. The proposed change also adds that for the purposes of §117.1105 and associated requirements, a unit is any utility boiler, auxiliary steam boiler, or stationary gas turbine (including any duct burner used in turbine exhaust ducts).

Subchapter B, Combustion Control at Major Industrial, Commercial, and Institutional Major Sources in Ozone Nonattainment Areas

Division 2, Bexar County Ozone Nonattainment Area Major Sources

The proposed rulemaking adds new Subchapter B, Division 2 to include RACT rules for major sources in Bexar County as required by FCAA §172(c)(1) and §182(f). The proposed new division sets NO_x emission limits for major sources in Bexar County and includes requirements necessary to demonstrate compliance with these limits, including monitoring, testing, reporting, and recordkeeping requirements. The proposed requirements are based on and are consistent with EPA-approved requirements for other nonattainment areas in the state.

Proposed new §117.200 specifies the rule applicability for the division. The proposed new division applies to stationary gas turbines, duct burners used in turbine exhaust ducts, and gas-fired lean-burn stationary reciprocating internal combustion engines located at any major stationary source of NO_x in Bexar County.

Proposed new §117.203 lists the units that are exempt from this division, except for the monitoring, testing, recordkeeping, and reporting requirements in proposed new §§117.240(i), 117.245(f)(4) and (9), and 117.252, which are necessary to document that the unit meets the exemption criteria. The proposed rule exempts stationary gas turbines and gas-fired lean-burn stationary reciprocating internal combustion engines that are used: in research and testing of the unit; for purposes of performance verification and testing of the unit; solely to power other gas turbines or engines during startups; exclusively in emergency situations, except that operation for testing or maintenance purposes of the gas turbine or engine is allowed for up to 100 hours per year, based on a rolling 12-month basis; or in response to and during the existence of any officially declared disaster or state of emergency. The proposed rule also exempts gas-fired lean-burn stationary reciprocating internal combustion engines with a horsepower (hp) rating less than 50 hp, and stationary gas turbines with a maximum rated capacity less than 10.0 million British thermal units per hour (MMBtu/hr). These proposed exemptions are consistent with EPA-approved exemptions for these same sources in other ozone nonattainment areas in Texas. The proposed rule also clarifies that units located at a major source that is subject to the proposed requirements for electric generating units in Subchapter C, Division 2 are exempt from this division.

Proposed new §117.205 lists the NO_X emission specifications for RACT for affected units at major sources in Bexar County. Proposed subsection (a) limits NO_X emissions from stationary gas turbines to 0.55 pound per million British thermal unit (lb/MMBtu); limits NO_X emissions from duct burners used in turbine exhaust ducts to 0.55 lb/MMBtu; and limits NO_X emissions from gas-fired lean-burn stationary reciprocating internal combustion engines to 0.5 gram per horsepower-hour. The proposed limits are the same as limits for RACT sources in other nonattainment areas in Texas and are achievable using technologically and economically feasible controls. Proposed subsection (b) states that the emission specifications apply on a block one-hour average, in the units of the applicable emission specification, or if the unit is operated with a NO_x CEMS or PEMS the limits apply on a rolling 30-day average, in the units of the applicable emission specification. Proposed subsection (c) clarifies that the owner or operator may use emission credits for compliance with these emission specifications in accordance with §117.9800. This option is consistent with compliance options provided for RACT sources in other nonattainment areas in the state. Proposed subsection (d) lists requirements that are intended to prevent circumvention of these rules. Proposed subsection (d) specifies that the maximum rated capacity used to determine the applicability of the emission specifications in this section and the other associated requirements in this division must be the greater of the maximum rated capacity as of December 31, 2019; the maximum rated capacity after December 31, 2019; or the maximum rated capacity authorized by a permit issued under Chapter 116 after December 31, 2019. Proposed subsection (d) also states that the unit's classification is determined by the most specific classification applicable to the unit as of December 31, 2019. For example, a unit that is classified as a gas-fired lean-burn stationary reciprocating internal combustion engine as of December 31, 2019, but subsequently is authorized to operate as a dual-fuel engine, is classified as a gas-fired lean-burn stationary reciprocating internal combustion engine for the purposes of this chapter. Proposed subsection (d) also requires that a source that met the definition of major source on December 31, 2019, is always classified as a major source for purposes of this chapter. A source that did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2019, but becomes a major source at any time after December 31, 2019, is from that time forward always classified as a major source for purposes of this chapter. December 31, 2019, was selected since 2019 is the emissions inventory year used in the attainment demonstration SIP modeling.

Proposed new §117.230 lists the operating requirements for units subject to the §117.205 RACT limits and requires all units to be operated to minimize NO_x emissions over the unit's operating or load range during normal operations. The proposed rule requires each unit controlled with post-combustion control techniques to 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. The proposed rule also requires each gas-fired lean-burn stationary reciprocating internal combustion engine to be checked for proper operation in accordance with the engine monitoring requirements in to §117.8140(b). These proposed operating requirements are consistent with EPA-approved requirements for these same sources in other ozone nonattainment areas in Texas.

Proposed new §117.235 contains the requirements for the initial demonstration of compliance with the proposed new §117.205 RACT limits. Proposed subsection (a) requires the owner or operator of any unit subject to the emission specifications in §117.205 to test the unit for NO_x and oxygen (O_2) emissions while firing gaseous fuel or, as applicable, liquid, and solid fuel. Proposed subsection (b) requires the initial demonstration of compliance testing to be performed in accordance with the compliance schedule in proposed new §117.9010. Proposed subsection (c) requires the initial demonstration of compliance tests to use the methods referenced in subsection (d) or (e). The proposal requires the tests be used for determination of initial compliance with the RACT emission specifications and requires test results to be reported in the units of the applicable emission specifications and averaging periods. Proposed new subsection (d) specifies that any CEMS or PEMS required by §117.240 must be installed and operational before conducting the required tests. The proposal specifies that verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system. Proposed new subsection (e) states that for units operating without CEMS or PEMS, compliance with the emission specifications must be demonstrated according to the stack testing requirements in §117.8000. Proposed new subsection (f) states that for units operating with CEMS or PEMS, initial compliance with the emission specifications must be demonstrated after monitor certification testing using the CEMS or PEMS. For units complying with a NO_x emission specification on a block one-hour average, every 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 specification. Proposed new subsection (g) requires compliance stack test reports to include the information required in §117.8010. These proposed requirements are consistent with EPA-approved requirements for these same sources in other ozone nonattainment areas in Texas.

Proposed new §117.240 includes the requirements for continuous demonstration of compliance with the RACT emission specifications. Proposed new subsection (a) requires units to have totalizing fuel flow meters, with an accuracy of ± 5%, to individually and continuously measure the gas and liquid fuel usage. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The owner or operator must continuously operate the totalizing fuel flow meter at least 95% of the time when the unit is operating during a calendar year. For the purpose of compliance with this subsection for units having pilot fuel supplied by a separate fuel system or from an unmonitored portion of the same fuel system, the fuel flow to pilots may be calculated using the manufacturer's design flow rates rather than measured with a fuel flow meter. The calculated pilot fuel flow rate must be added to the monitored fuel flow when fuel flow is totaled. Proposed subsection (a) also provides alternatives to the fuel flow monitoring requirements. The proposed alternative for units operating with a NO_x and diluent CEMS may monitor stack exhaust flow using the flow monitoring specifications of 40 CFR Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A. Units that vent to a common stack with a NO_x and diluent CEMS may use a single totalizing fuel flow meter. Gas-fired lean-burn stationary reciprocating internal combustion engines and gas turbines equipped with a continuous monitoring system that continuously monitors horsepower and hours of operation are not required to install totalizing fuel flow meters. The continuous monitoring system for such units must be installed, calibrated, maintained, and operated according to manufacturers' recommended procedures.

Proposed new subsection (b) specifies the requirements for NO_x monitors. The proposal requires using a CEMS or PEMS to monitor exhaust NO_x for units with a rated heat input greater than or equal to 100 MMBtu per hour; stationary gas turbines with a megawatt (MW) rating greater than or equal to 30 MW operated more than 850 hours per year; units that use a chemical reagent for reduction of NO_x; and units that the owner or operator elects to comply with the NO_x emission specifications of §117.205(a) using a pound per MMBtu limit on a 30-day rolling average. The proposal specifies that units subject to the NO_x CEMS requirements of 40 CFR Part 75 are not required to install CEMS or PEMS under this subsection. The proposal provides options that the owner or operator must use to provide substitute emissions compliance data during periods when the NO_x monitor is off-line. The proposal requires that if the NO_x monitor is a CEMS subject to 40 CFR Part 75, the missing data procedures specified in 40 CFR Part 75, Subpart D must be to provide substitute emissions compliance data during periods when the NO_x monitor is off-line. The proposal requires that if the NO_x monitor is a CEMS subject to subject to 40 CFR Part 75, Appendix E, the missing data procedures specified in 40 CFR Part 75, Appendix E, §2.5 must be used to provide substitute emissions compliance data during periods when the NO_x monitor is off-line. The proposal requires that if the NOX monitor is a PEMS, the methods specified in 40 CFR Part 75, Subpart D or calculations in accordance with §117.8110(b) must be used to provide substitute emissions compliance data during periods when the NO_x monitor is off-line. The owner or operator can monitor operating parameters for each unit in accordance with 40 CFR Part 75, Appendix E, §1.1 or §1.2 and calculate NO_x emission rates based on those procedures. Lastly, the owner or operator can use the maximum block one-hour emission rate as measured during the initial demonstration of compliance required in §117.235.

Proposed new subsection (c) requires the owner or operator of any CEMS used to meet a pollutant monitoring requirement of this section to comply with the emission monitoring system requirements of §117.8100(a). Proposed new subsection (d) requires any PEMS used to meet a pollutant monitoring requirement of this section must predict the pollutant emissions in the units of the applicable emission limit and must meet the emission monitoring system requirements of §117.8100(b). Proposed new subsection (e) requires the owner or operator of any gas-fired lean-burn stationary reciprocating internal combustion engine subject to the emission specifications in §117.205 to stack test engine NO_x emissions as specified in §117.8140(a). Proposed new subsection (f) requires the owner or operator of any stationary gas turbine or gas-fired lean-burn stationary reciprocating internal combustion engine claimed exempt using the exemption of §117.203(1)(D) to record the operating time with a non-resettable elapsed run time meter in order to the unit meets the exemption criteria. Proposed new subsection (g) requires that after the initial demonstration of compliance required by §117.235, the methods required in this section must be used to determine compliance with the emission specifications. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the unit is in compliance with applicable emission specifications. Proposed new subsection (h) requires the owner or operator of units that are subject to the emission specifications in §117.205 to test the units as specified in §117.235 in accordance with the applicable schedule specified in §117.9010. The proposal also requires the owner or operator of any unit not equipped with CEMS or PEMS that are subject to the emission specifications of §117.205 to retest the unit as specified in §117.235 within 60 days after any modification that could reasonably be expected to increase the NO_X emission rate.

Proposed new section §117.245 includes the notification, recordkeeping, and reporting requirements necessary to demonstrate compliance with this division. Proposed new subsection (a) requires that for units subject to the startup and/or shutdown provisions of §101.222, hourly records must be made of startup and/or shutdown events and maintained for a period of at least two years. Records must be available for inspection by the executive director, the EPA, and any local air pollution control agency having jurisdiction upon request. These records must 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. Proposed new subsection (b) requires the owner or operator of a unit subject to the emission specifications of §117.205 to submit written notification of any CEMS or PEMS relative accuracy test audit (RATA) conducted under §117.240 or any testing conducted under §117.235 at least 15 days in advance of the date of the RATA or testing to the appropriate regional office and any local air pollution control agency having jurisdiction. Proposed new subsection (c) requires the owner or operator of a unit subject to the emission specifications of §117.205(a) to furnish the Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction a copy of any testing conducted under §117.235 and any CEMS or PEMS RATA conducted under §117.240 within 60 days after completion of such testing or evaluation and not later than the compliance date specified in §117.9010.

Proposed new §117.245(d) requires the owner or operator of a unit required to install a CEMS or PEMS under §117.240 to report in writing to the executive director on a semiannual basis any exceedance of the applicable emission specifications of this division and the monitoring system performance. All reports must be postmarked or received by the 30th day following the end of each calendar semiannual period (i.e., July 30 and January 30). The proposal specifies that the written reports must include the magnitude of excess emissions computed in accordance with 40 CFFR §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. The reports must specifically identify each period of excess emissions that occurs during startups, 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. The reports must include the date and time identifying each period when the continuous monitoring system was inoperative (except for zero and span checks), the nature of the system repairs or adjustments, and periods when no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted. The proposal specifies that 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) must be submitted, unless otherwise requested by the executive director, 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 or PEMS downtime for the reporting period is less than 5.0% of the total unit operating time for the reporting period. If the total duration of excess emissions for the reporting period is greater than or equal to 1.0% of the total unit operating time for the reporting period or the CEMS or PEMS downtime for the reporting period is greater than or equal to 5.0% of the total unit operating time for the reporting period, a summary report and an excess emission report must both be submitted.

Proposed new subsection (e) requires the owner or operator of any gas-fired engine subject to the emission specifications in §117.205 to report in writing to the executive director on a semiannual basis any excess emissions and the air-fuel ratio monitoring system performance. All reports must be postmarked or received by the 30th day following the end of each calendar semiannual period (i.e., July 30 and January 30). The proposal specifies that the written reports must include the magnitude of excess emissions (based on the quarterly emission checks of §117.230(a)(2)) and the biennial emission testing required in accordance with §117.240(e), 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. The report must also specifically identify, to the extent feasible, of each period of excess emissions that occurs during startups, 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.

Proposed new subsection (f) requires the owner or operator of a unit subject to the requirements of this division to maintain written or electronic records of the data specified in this subsection. Such records must be kept for a period of at least five years and must be made available upon request by authorized representatives of the executive director, the EPA, or local air pollution control agencies having jurisdiction. The proposal specifies that the records must include records of annual fuel usage for each unit subject to §117.240(a). For each unit using a CEMS or PEMS in accordance with §117.240, the records must include monitoring records of hourly emissions and fuel usage (or stack exhaust flow) for units complying with an emission specification enforced on a block one-hour average; or daily emissions and fuel usage (or stack exhaust flow) for units complying with an emission specification enforced on a daily or rolling

30-day average. Emissions must be recorded in units of pounds per million British thermal units (lb/MMBtu) heat input and pounds or tons per day. The proposal requires that for each stationary internal combustion engine subject to the emission specifications of this division, records must include emissions measurements required by §117.230(2) and §117.240(e) of this title; catalytic converter, air-fuel ratio controller, or other emissions-related control system maintenance, including the date and nature of corrective actions taken; and daily average horsepower and total daily hours of operation for each engine that the owner or operator elects to use the alternative monitoring system allowed under §117.240(a)(2)(C). The proposal requires that for units claimed exempt from emission specifications using the exemption in §117.203(a)(1)(D) records must include monthly hours of operation. In addition, for each turbine or engine claimed exempt under §117.203(a)(1)(D) or (E), written records must be maintained of the purpose of turbine or engine operation and, if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation. The proposal requires records of the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS or PEMS. The proposal also requires records of the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.235.

Proposed new §117.252 contains the control plan procedures for RACT. The proposal requires the owner or operator of any unit subject to §117.205 to maintain a control plan report to show compliance with the requirements of §117.205. The report must include a list of all units that are subject to §117.205 that specifies: the facility identification number and emission point number as submitted to the Emissions Assessment Section of the commission, the emission point number as listed on the Maximum Allowable Emissions Rate Table of any applicable commission permit; the maximum rated capacity; the method of NO_x control for each unit; the emissions measured by testing required in §117.235; the compliance stack test report or monitor certification report required by §117.235; and the use of any compliance flexibility in accordance with §117.9800. The report must also list all units with a claimed exemption from the emission specification of §117.205 and the specific rule citation claimed as the basis for any that exemption. The proposal requires the report to be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Office of Air by the applicable date specified for control plans in §117.9010. The proposal also specifies that for any unit that becomes subject to §117.205 after the applicable date specified in §117.9010, the report must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Office of Air no later than 60 days after becoming subject. The proposal specifies that if any of the information changes in a control plan report submitted in accordance with section, including the installation of functionally identical replacement units, the control plan must be updated no later than 60 days after the change occurs. Written or electronic records of the updated control plan must be kept for a period of at least five years and must be made available upon request by authorized representatives of the executive director, the EPA, or local air pollution control agencies having jurisdiction.

Division 3, Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources

The proposed rulemaking amends §117.310(c)(2) to specify that for diesel engines that inject urea or ammonia into the exhaust stream for NO_X control, ammonia emissions must not exceed 10 ppmv at 15% O_2, dry instead of 3% O_2, dry, as currently in effect. The existing rules require that ammonia emissions must not exceed 10 parts per million at 3.0% O_2, dry, for certain units that inject urea or ammonia into the exhaust stream for NO_X control. Correcting ammonia concentrations to the 3.0% O_2 level currently required is inappropriate for diesel engines that operate at significantly higher excess air in the exhaust stream. The proposed rule change to allow diesel engines to use the 15% O_2 correction consistent with the Chapter 117 standards for other equipment that also operates with higher O_2 in the exhaust gas.

The proposal would also amend §117.340(c)(2) to add proposed new subparagraph (C) to specify that CEMS and PEMS are not required to be installed on stationary diesel engines equipped with SCR systems using a reductant other than the engine's fuel with a diagnostic system that monitors reductant quality and tank levels and alerts operators to the need to refill the reductant tank before it is empty, or to replace the reductant if it does not meet applicable concentration specifications. The proposal states that if the SCR uses input from an exhaust NO_X sensor (or other sensor) to alert operators when reductant quality is inadequate, reductant quality does not need to be monitored separately. The proposal also requires the reductant tank level to be monitored in accordance with the manufacturer’s design to demonstrate compliance. The existing Chapter 117 requirement to monitor exhaust NO_X concentrations using CEMS or PEMS on units using a chemical reagent to reduce NO_X was included in the rule to ensure compliance with the applicable NO_X standards for units that rely on reagent-based emissions control systems that can be adjusted by the operator. Manufacturer-certified Tier 4 engines are designed to meet certain federal NO_X emissions limits and, as such, include SCR systems designed to monitor several parameters over which the operator has no control. The engines are intended to be tamper-resistant and not subject to alteration. Tier 4 engines are not manufactured with pre-installed CEMS because these inherent design standards ensure NO_X emissions conform to the Tier 4 standards. Given that the control system cannot be manipulated and considering the significant cost of installing and operating a CEMS, a CEMS or PEMS is not necessary to provide reasonable assurance of compliance with the NO_X emission standards. The commission is requesting comment on any changes that need to be made to the proposed language to ensure it applies to all of the engines intended to be covered by this exemption.

The proposal would also amend §117.340(d) to exempt these engines from the ammonia monitoring requirement in this subsection. It is not necessary to install CEMS or PEMS or monitor ammonia emissions from these engines since these engines are intended to be tamper resistant and not subject to alteration.

Division 4, Dallas-Fort Worth Ozone Nonattainment Area Major Sources

The proposed rulemaking amends §117.410(c)(2) to specify that for diesel engines that inject urea or ammonia into the exhaust stream for NO_X control, ammonia emissions must not exceed 10 ppmv at 15% O_2, dry instead of 3% O_2, dry. The existing rules require that ammonia emissions must not exceed 10 parts per million at 3.0% O_2, dry, for certain units that inject urea or ammonia into the exhaust stream for NO_X control. However, correcting ammonia concentrations to the 3.0% O_2 level currently required is inappropriate for diesel engines that operate at significantly higher excess air in the exhaust stream. The proposed rule change to allow diesel engines to use the 15% O_2 correction consistent with the Chapter 117 standards for other equipment that also operates with higher O_2 in the exhaust gas.

The proposal would also amend §117.440(c)(2) to include the existing reference to NO_X CEMS requirements of 40 CFR Part 75 as new subparagraph (A) and add proposed new subparagraph (B) to specify that CEMS and PEMS are not required to be installed on stationary diesel engines equipped with SCR systems using a reductant other than the engine's fuel with a diagnostic system that monitors reductant quality and tank levels and alerts operators to the need to refill the reductant tank before it is empty, or to replace the reductant if it does not meet applicable concentration specifications. The proposal states that if the SCR uses input from an exhaust

NO_X sensor (or other sensor) to alert operators when reductant quality is inadequate, reductant quality does not need to be monitored separately. The proposal also requires the reductant tank level to be monitored in accordance with the manufacturer's design to demonstrate compliance. The existing Chapter 117 requirement to monitor exhaust NO_X concentrations using CEMS or PEMS on units using a chemical reagent to reduce NO_X was included in the rule to ensure compliance with the applicable NO_X standards for units that rely on reagent-based emissions control systems that can be adjusted by the operator. Manufacturer-certified Tier 4 engines are designed to meet certain federal NO_X emissions limits and, as such, include SCR systems designed to monitor several parameters over which the operator has no control. The engines are intended to be tamper-resistant and not subject to alteration. Tier 4 engines are not manufactured with pre-installed CEMS because these inherent design standards ensure NO_X emissions conform to the Tier 4 standards. Given that the control system cannot be manipulated and considering the significant cost of installing and operating a CEMS, a CEMS or PEMS is not necessary to provide reasonable assurance of compliance with the NO_X emission standards. The commission is requesting comment on any changes that need to be made to the proposed language to ensure it applies to all of the engines intended to be covered by this exemption.

The proposal would also amend §117.440(d) to exempt these engines from the ammonia monitoring requirement in this subsection. It is not necessary to install CEMS or PEMS or monitor ammonia emissions from these engines since these engines are intended to be tamper resistant and not subject to alteration.

Subchapter C, Combustion Control at Major Utility Electric Generation Sources in Ozone

Nonattainment Areas

Division 2, Bexar County Ozone Nonattainment Area Utility Electric Generation Sources

Proposed new §117.1100 specifies the rule applicability for the division. The proposed new division applies to utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in turbine exhaust ducts used in an electric power generating system in Bexar County. The proposed rule states that this division is applicable for the life of each affected unit in an electric power generating system or until this division or sections of this title that are applicable to an affected unit are rescinded.

Proposed new §117.1103 lists the units that are exempt from this division, except the monitoring, recordkeeping and reporting requirements that are necessary to document that the unit meets the exemption criteria. The proposed exemption applies to (1) any utility boiler or auxiliary steam boiler with an annual heat input less than or equal to 220,000 MMBtu per year; (2) any stationary gas turbines that operate less than 850 hours per year, based on a rolling 12-month basis; and (3) any stationary gas turbines that are used solely to power other gas turbines or engines during startups.

Proposed new §117.1105 contains the emission specifications RACT that sources must comply with in accordance with the applicable schedule in proposed new §117.9110. The emission specifications were determined to be both technologically and economically feasible. The emission rates are consistent with EPA-approved RACT limits for similar sources in the other nonattainment areas in the state and permit limits for this type of unit. The proposed new subsection (a)(1) limits NO_x emissions from stationary gas turbines, including duct burners used in turbine exhaust ducts, to 0.032 lb/MMBtu heat input on a rolling 30-day average basis. The proposed new subsection (a)(2) limits NO_x emissions from utility boilers or auxiliary steam boilers, while firing natural gas or a combination of natural gas and oil to 0.2 lb/MMBtu heat input on a rolling 30-day average basis. The proposed new subsection (a)(3) limits NO_x emissions from utility boilers or auxiliary steam boilers controlled with SCR, while firing coal, to 0.069 lb/MMBtu heat input on a rolling 30-day average basis. The proposed new subsection (a)(4) limits NO_x emissions from utility boilers or auxiliary steam boilers not controlled with SCR, while firing coal, to 0.20 lb/MMBtu heat input on a rolling 30-day average basis. The proposed new subsection (a)(5) limits NO_x emissions from utility boilers or auxiliary steam boilers, while firing oil only to 0.30 lb/MMBtu heat input on an hourly basis. Compliance with proposed emission specifications on a rolling 30-day average beginning on January 1, 2025, will be based on CEMS or PEMS data from the previous 30 operating days. The proposed new subsection (b) provides compliance flexibility by including options for sources to meet a system cap or use emission credits to comply with the NO_x emission specifications of this section.

The proposal adds new §117.1120 to add system cap option for affected sources. The proposed new subsection (a) allows an owner or operator of an electric generating facility (EGF) to achieve compliance with the NO_x emission specifications in §117.1105 by achieving equivalent NO_x emission reductions obtained by compliance with a 30-day system cap emission limitation in accordance with the requirements of this section. Proposed new subsection (b) requires each EGF within an electric power generating system that started operation before January 1, 2025 (which is the proposed compliance date for this division), and is subject to §117.1105 to be included in the system cap. Proposed new subsection (c) provides an equation to calculate the rolling 30-day system cap. The 30-day rolling average NO_x emission cap in pounds per day is the product of the applicable emission specification in §117.1105 for each EGF times the average of the daily heat input for each EGF in the emission cap in MMBtu per day for any system 30-day period in 2019, 2020, 2021, 2022, or 2023 (the same 30-day period must be used for all EGFs in the emission cap). This value is then summed for all EGFs in the electric power generating system. Proposed new subsection (d) indicates that compliance with the system cap must be demonstrated in accordance with the requirements in proposed new §117.1140 and proposed new subsection (e) indicates that records, including semiannual reports for the monitoring systems, must be retained in accordance with proposed new §117.1145. The proposal requires sources to comply with the system cap in accordance with the schedule specified in proposed new§117.9110. Proposed new subsection (g) requires any exceedance of the system cap emission limit to be reported within 48 hours and requires a written report that includes a root cause analysis and corrective actions to be submitted within 21 days of the exceedance. Proposed new subsection (h) allows an EGF that is permanently retired or decommissioned and rendered inoperable to continue to be included in the system cap emission limit provided that the permanent shutdown occurred on or after the January 1, 2025 compliance date for this division. Proposed new subsection (i) prohibits emission reductions from shutdowns or curtailments that have been used for netting or offset purposes for an air permit issued under 30 TAC Chapter 116 from being included in the in the calculation of the system cap. Proposed new subsection (j) indicates that for the purposes of determining compliance with the system cap, the contribution of each affected EGF that is operating during a startup, shutdown, or emissions event must be calculated from the NO_X emission rate measured by the NO_X monitor, if the monitor is operating properly, or if the NO_X monitor is not operating properly, the substitute data procedures identified in §117.1140 must be used. Proposed new subsection (k) allows emission credits may be used in accordance with the requirements of §117.9800 to exceed the system cap.

The proposal adds new §117.1140 to specify the requirements for demonstrating compliance with the proposed new emission limits. Proposed new subsection (a) requires owners or operators to install, calibrate, maintain, and operate a CEMS or PEMS to measure NO_x on an individual basis for all units subject to the proposed new emission specifications in §117.1105. The proposal requires each CEMS or PEMS to comply with the relative accuracy test audit relative accuracy (RATA) requirements of 40 CFR Part 75, Appendix B, Figure 2, except the concentration options (parts per million by volume (ppmv) and lb/MMBtu) do not apply. The proposal also requires each CEMS or PEMS to meet either the relative accuracy percent requirement of 40 CFR Part 75, Appendix B, Figure 2, or an alternative relative accuracy requirement of ± 2.0 ppmv from the reference method mean value. The proposal requires CEMS or PEMS to comply with the emission monitoring system requirements of §117.8110. The proposal requires PEMS to predict NO_x emissions in the units of the applicable emission limitations and requires that data and fuel flow meters to be used to demonstrate continuous compliance. Proposed new subsection (b) provides acid rain peaking units the option to monitor operating parameters for each unit in accordance with 40 CFR Part 75, Appendix E, and calculate NO_x emission rates based on those procedures instead of using a CEMS or PEMS.

Proposed new §117.1140(c) also requires units subject to the proposed new emission specifications in §117.1105 and units claiming exemption under proposed new §117.1103(1) to use totalizing fuel flow meters to individually and continuously measure the gas and liquid fuel usage unless the owner or operator opts to assume fuel consumption at maximum design fuel flow rates during hours of the unit's operation. The proposal indicates that a computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. Proposed new subsection (d) requires that a unit using the proposed exemption in §117.1103(2) record the operating time hours with an elapsed run time meter. Proposed new subsection (e) requires the owner or operator of any unit using the proposed new exemptions in §117.1103(1) or (2) to notify the executive director within seven days if the applicable limit is exceeded and to submit a plan for review and approval within 90 days after loss of the exemption that details the schedule to meet the applicable limit no later than 24 months after the exceedance. The proposal indicates that if the limit is exceeded, the exemption from the emission specifications of this division is permanently withdrawn.

Proposed new §117.1140(f) requires the methods in this section to be used to demonstrate compliance with the proposed new emission specifications of §117.1105 and the proposed new system cap in §117.1120. The proposal allows the executive director to use other commission compliance methods to determine compliance with applicable emission specifications for enforcement purposes. The proposal explains that for units complying with the NO_x emission specifications of §117.1105 in lb/MMBtu on a rolling 30-day average basis, the rolling 30-day average is calculated for each day that fuel was combusted in the unit, and is the total pounds of NO_x emissions from the unit for the preceding 30 days that fuel was combusted in the unit, divided by the total heat input (in MMBtu) for the unit during the same 30-day period. The proposal also explains that for any EGF complying with system cap in §117.1120 in pounds per day on a rolling 30-day average basis, the rolling 30-day average is calculated for each day that fuel was combusted in the unit and is the average of the total pounds of NO_x emissions per day from all EGFs included in the system cap for the preceding 30 days that fuel was combusted in the units. Proposed new subsection (g) requires the missing data procedures specified in 40 CFR Part 75, Subpart D to be used to provide substitute emissions compliance data during periods when the NO_x monitor is off-line except that a peaking unit may use the missing data procedures specified in 40 CFR Part 75, Appendix E, §2.5 and a PEMS for units not subject to the requirements of 40 CFR Part 75 may use calculations in accordance with §117.8110(b). The commission is requesting comment on any additional data substitution procedures that may be appropriate.

Proposed new §117.1145 adds notification, recordkeeping, and reporting requirements. Proposed new subsection (a) requires written notification of any CEMS or PEMS RATA conducted under §117.1140 to be submitted at least 15 days prior to such date and (b) requires a copy of the results of any CEMS or PEMS RATA conducted under §117.1140 to be submitted within 60 days after completion of such testing or evaluation. Proposed new subsection (c) requires units subject to the startup and/or shutdown provisions of §101.222, to maintain hourly records of startup and/or shutdown events (including but not limited to the type of fuel burned; quantity of each type of fuel burned; gross and net energy production in megawatt-hours; and the date, time, and duration of the event) for a period of at least two years. The proposed rule specifies that the records must be available for inspection upon request by the executive director, EPA, and any local air pollution control agency having jurisdiction.

Proposed new §117.1145(d) requires the owner or operator of a unit required to install a CEMS or PEMS under proposed new §117.1140 to report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations in this division and the monitoring system performance. All reports must be postmarked or received by the 30th day following the end of each calendar semiannual period (i.e., July 30 and January 30). The proposal requires the reports to include (1) the magnitude of excess emissions computed in accordance with 40 CFR §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; (2) specific identification of each period of excess emissions that occurs during startups, 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; and (3) the date and time identifying each period when the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments. The proposal indicates that when no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information must be stated in the report. The proposal specifies that 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) is required 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 or PEMS monitoring system downtime for the reporting period is less than 5.0% of the total unit operating time for the reporting period (unless otherwise requested by the executive director). The proposal requires both a summary report and an excess emission report to be submitted if the total duration of excess emissions for the reporting period is greater than or equal to 1.0% of the total unit operating time for the reporting period or the CEMS or PEMS downtime for the reporting period is greater than or equal to 5.0% of the total unit operating time for the reporting period.

Proposed new §117.1145(e) lists the required records, which must be kept for at least five years and must be made available upon request by authorized representatives of the executive director, EPA, or local air pollution control agencies having jurisdiction. Proposed new paragraph (1) requires the owner or operator of a unit complying with the NO_x emission specifications in §117.1105(a)(1) – (4) to maintain daily records indicating the NO_x emissions in lb; the quantity and type of each fuel burned; the heat input in MMBtu; and the rolling 30-day average NO_x emission rate in lb/MMBtu. Proposed new paragraph (2) requires the owner or operator of a unit complying with the NO_x emission specification in §117.1105(a)(5) to maintain hourly records indicating the NO_x emissions in lb; the quantity and type of each fuel burned; and the heat input in MMBtu. Proposed new paragraph (3) requires the owner or operator complying with the NO_x emission system cap in §117.1120 to maintain daily records for each EGF in the cap indicating the NO_x emissions in lb; the quantity and type of each fuel burned; and the heat input in MMBtu. In addition, the owner or operator shall maintain daily records indicating the total NO_x emissions in lb from all EGFs under the system cap and the rolling 30-day average NO_x emissions rate (in lb/day) for all EGFs under the system cap. Proposed new paragraph (4) requires the owner or operator of a unit using the exemption in §117.1103(1) to maintain monthly records indicating the quantity and type of each fuel burned, the heat input in MMBtu; and the rolling 12-month average heat input in MMBtu. Proposed new paragraph (5) requires the owner or operator of a unit the exemption in §117.1103(2) to maintain monthly records indicating the operating hours and the rolling 12-month average operating hours. Proposed new paragraph (6) requires the owner or operator to maintain records of records of the results of testing, evaluations, calibrations, checks, adjustments, and maintenance of a CEMS or PEMS.

Proposed new §117.1152 contains the control plan procedures for RACT. Proposed new subsection (a) requires the owner or operator of any unit subject to §117.1105 to submit a control plan report to show compliance with the requirements of §117.1105. The report must include: (1) the rule section used to demonstrate compliance, either §117.1105, §117.1120, or §117.9800; (2) the specific rule citation for any unit with a claimed exemption under §117.1105; (3) for each affected unit: the method of NO_x control, the method of monitoring emissions, and the method of providing substitute emissions data when the NO_x monitoring system is not providing valid data; and (4) for sources complying with §117.1120, detailed calculation of the system cap that includes all data relied on for each electric generating facility included in the system cap equation in §117.1120(c). Proposed new subsection (b) requires report to be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Office of Air by the applicable date specified for control plans in §117.9110. Proposed new subsection (c) specifies that for any unit that becomes subject to §117.1105 after the applicable date for control plans in §117.9110, the control plan must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Office of Air no later than 60 days after becoming subject. Proposed new subsection (d) requires that if any of the information changes in a control plan report submitted in accordance with subsection (b) or (c), including the installation of functionally identical replacements, the control plan must be updated no later than 60 days after the change occurs. Written or electronic records of the updated control plan must be kept for a period of at least five years and must be made available upon request by authorized representatives of the executive director, the EPA, or local air pollution control agencies having jurisdiction.

Subchapter D, Combustion Control at Minor Sources in Ozone Nonattainment Areas

Division 1, Houston-Galveston-Brazoria Ozone Nonattainment Area Minor Sources

The proposed rulemaking amends §117.2010(i)(2) to specify that for diesel engines that inject urea or ammonia into the exhaust stream for NO_x control, ammonia emissions must not exceed 10 ppmv at 15% O_2, dry instead of 3% O_2, dry. The existing rules require that ammonia emissions must not exceed 10 parts per million at 3.0% O_2, dry, for certain units that inject urea or ammonia into the exhaust stream for NO_x control. However, correcting ammonia concentrations to the 3.0% O_2 level currently required is inappropriate for diesel engines that operate at significantly higher excess air in the exhaust stream. The proposed rule change to allow diesel engines to use the 15% O_2 correction is consistent with the Chapter 117 standards for other equipment that also operate with higher O_2 in the exhaust gas.

The proposal would amend §117.2035(e)(2) to specify that the ammonia monitoring requirements in this paragraph do not apply to stationary diesel engines equipped with selective catalytic reduction systems that meet the following criteria. The SCR system must use a reductant other than the engine's fuel and operate with a diagnostic system that monitors reductant quality and tank levels. The diagnostic system must alert owners or operators to the need to refill the reductant tank before it is empty or to replace the reductant if the reductant does not meet applicable concentration specifications. If the SCR system uses input from an exhaust NO_X sensor (or other sensor) to alert owners or operators when the reductant quality is inadequate, the reductant quality does not need to be monitored separately by the diagnostic system. The reductant tank level must be monitored in accordance with the manufacturer's design to demonstrate compliance with this subparagraph. The method of alerting an owner or operator must be a visual or audible alarm.

Division 2, Dallas-Fort Worth Eight Hour Ozone Nonattainment Area Minor Sources

The proposed rulemaking amends §117.2110(h)(2) to specify that for diesel engines that inject urea or ammonia into the exhaust stream for NO_X control, ammonia emissions must not exceed 10 ppmv at 15% O_2, dry instead of 3% O_2, dry. The existing rules require that ammonia emissions must not exceed 10 parts per million at 3.0% O_2, dry, for certain units that inject urea or ammonia into the exhaust stream for NO_X control. However, correcting ammonia concentrations to the 3.0% O_2 level currently required is inappropriate for diesel engines that operate at significantly higher excess air in the exhaust stream. The proposed rule change to allow diesel engines to use the 15% O_2 correction is consistent with the Chapter 117 standards for other equipment that also operate with higher O_2 in the exhaust gas.

The proposal would amend §117.2135(d)(2) to specify that the ammonia monitoring requirements in this paragraph do not apply to stationary diesel engines equipped with selective catalytic reduction systems that meet the following criteria. The SCR system must use a reductant other than the engine's fuel and operate with a diagnostic system that monitors reductant quality and tank levels. The diagnostic system must alert owners or operators to the need to refill the reductant tank before it is empty or to replace the reductant if the reductant does not meet applicable concentration specifications. If the SCR system uses input from an exhaust NO_X sensor (or other sensor) to alert owners or operators when the reductant quality is inadequate, the reductant quality does not need to be monitored separately by the diagnostic system. The reductant tank level must be monitored in all cases in accordance with the manufacturer’s design to demonstrate compliance with this subparagraph. The method of alerting an owner or operator must be a visual or audible alarm.

Subchapter E, Multi-Region Combustion Control

Division 1, Utility Electric Generation in East and Central Texas

The proposed rule amends the applicability in §117.3000 to specify that this division no longer applies in Bexar County after December 31, 2024. This change ensures that units in Bexar County will remain in compliance with the existing rule until they are required to comply with the proposed new rules for EGUs in Subchapter C, Division 2.

Division 2, Cement Kilns

The proposed rule amends §117.3103 for portland cement kilns exempted from the provisions of this division, to include any portland cement kiln placed into service on or after December 31, 1999, except as specified in proposed new Bexar County RACT requirements in §117.3124. The proposed amendments also state that after the compliance date specified in §117.9320(c), portland cement kilns that are subject to §117.3124 are exempt from §117.3110 and §117.3120 of this title. These proposed changes are necessary to ensure that cement kilns in Bexar County will remain in compliance with the existing rule until they are required to comply with the proposed new RACT requirements in §117.3124.

The proposed rulemaking adds language to the emission specification in §117.3110 and the source cap requirements in §117.3120 to state that these sections no longer apply in Bexar County after December 31, 2024. These proposed changes are necessary to ensure that cement kilns in Bexar County are subject to these rules only until they are required to comply with the proposed new RACT requirements in §117.3124.

Proposed new §117.3124 lists the Bexar County control requirements for RACT.
The proposed rule limits NO_x emissions from each preheater-precalciner or precalciner kiln Bexar County to 2.8 pounds per ton (lb/ton) of clinker produced on a 30-day rolling average beginning on the compliance date specified in §117.9320. This proposed limit is consistent with limits for this type of kiln in other state and federal rules. For one of the two affected kilns, this limit represents an approximate 40% reduction from the average NO_x emissions from 2017-2022. The other affected kiln is currently operating below this rate and the commission is requesting comments on the technological and economic feasibility of the existing kiln located at Capital Cement to meet a limit of 1.95 lb/ton of clinker produced on a 30-day rolling average during both normal conditions and during maintenance, startup, and shutdown. The proposed new section clarifies that for the purposes of this section, the 30-day rolling average is an average, calculated for each day that fuel was combusted in the cement kiln, as the total of all the hourly emissions data (in pounds) for the preceding 30 days that fuel was combusted in the cement kiln, divided by the total number of tons of clinker produced in that kiln during the same 30-day period. The proposed rule also states that an owner or operator may use emission credits in accordance with §117.9800 to meet the NO_x emission control requirements of this

section, in whole or in part.

The proposed rule amends the notification, recordkeeping, and reporting requirements in 117.3145 to require monitoring records for kilns subject to §117.3124 to include the hourly, daily, and rolling 30-day average NO_x emissions (in pounds); the hourly, daily, and rolling 30-day average production of clinker (in United States short tons); and the rolling 30-day average NO_x emission rate (in lb/ton of clinker produced). These records are necessary to demonstrate compliance with the proposed new RACT requirements for kilns in Bexar County.

Subchapter H, Administrative Provisions

Division 1, Compliance Schedules

The proposal adds new §117.9010 to include the compliance schedule for Bexar County ozone nonattainment area major sources. The proposal requires the owner or operator of any stationary source of NO_x in Bexar County that is a major source of NO_x and is subject to the requirements of Subchapter B, Division 2 to comply with the requirements that division as soon as practicable, but no later than January 1, 2025. The proposal also requires the owner or operator of any stationary source of NO_x that becomes subject to the requirements of Subchapter B, Division 2 on or after January 1, 2025 to comply with the requirements of the division as soon as practicable, but no later than 60 days after becoming subject.

The proposal amends the compliance schedule for DFW area major sources in §117.9030 to add that for units subject to the emission specifications of §117.405(b) located at sources in Wise County that emit or have the potential to emit equal to or greater than 25 tpy but less than 50 tpy of NO_x submission of the initial control plan required by §117.450(b) is required no later than May 7, 2025; and compliance with all other requirements of Subchapter B, Division 4 is required as soon as practicable, but no later than November 7, 2025. The proposal adds requirements for the owner or operator of any unit that is subject to the emission specifications in §117.410(a) located in the Dallas-Fort Worth eight-hour ozone nonattainment area that emits or have the potential to emit equal to or greater than 25 tpy but less than 50 tpy of NO_x to submit the initial control plan required by §117.450(b) no later than May 7, 2025; and comply with all other requirements of Subchapter B, Division 4 as soon as practicable, but no later than November 7, 2025. The proposal also states that the owner or operator of any stationary source of NO_x that becomes subject to the emission specifications in §117.410(a) on or after the applicable compliance date specified in paragraph (2) must comply with the requirements of Subchapter B, Division 4 as soon as practicable, but no later than 60 days after becoming subject.

The proposal adds new §117.9110 to include the compliance schedule for Bexar County ozone nonattainment area utility electric generation sources. The proposal requires the owner or operator of each electric utility in Bexar County to comply with the requirements of Subchapter C, Division 2 as soon as practicable, but no later than January 1, 2025. The proposal also requires the owner or operator of any electric utility that becomes subject to the requirements of Subchapter C, Division 2 on or after January 1, 2025, to comply with the requirements of that division as soon as practicable, but no later than 60 days after becoming subject.

The proposal amends §117.9300 to specify that beginning January 1, 2025, sources in Bexar County are no longer required to comply with the requirements of Subchapter E, Division 1. This change ensures that sources must comply with these requirements only until compliance with the proposed new RACT rules in Subchapter C, Division 2 is required.

The proposal amends 117.9320 to require the owner or operator of each portland cement kiln in Bexar County to comply with the requirements of §117.3124 and the applicable requirements of §117.3145 as soon as practicable, but no later than January 1, 2025.

Division 2, Compliance Flexibility

The proposal amends §117.9800 to allow for the use of emission credits for compliance with the proposed new Bexar County RACT requirements in §§117.205, 117.1105, 117.1120, and 117.3124. The proposal also specifies that for units using reduction credits in accordance with this section that are subject to new, more stringent rule limitations, the owner or operator using the reduction credits must submit a revised final control plan to the executive director in accordance with §117.1152. These requirements are the same as the EPA-approved options provided for other nonattainment areas in the state.

Fiscal Note: Costs to State and Local Government

Kyle Girten, Analyst in the Budget and Planning Division, has determined that for the first five-year period the proposed rules are in effect, no costs are anticipated for the agency as a result of administration or enforcement of the proposed rule.

Fiscal implications are anticipated for the University of Texas Southwestern Medical Center which has two sites that may be impacted by revisions to Subchapter A and Subchapter H that lower the threshold for major sources from 50 tpy NO_X to 25 tpy NO_X. This would result in increased costs associated with three boilers totaling over $210,000 in the first year and over $10,000 per year for years two through five. Additionally, there would be increased costs associated with 27 diesel/oil fired engines that total over $270,000 in the first year, over $24,000 in years two and four, and over $185,000 in years three and five. Increased costs in the first year are attributed to capital purchases, and variation in subsequent years is attributed to alternating testing requirements from year to year. The total costs for this state institution would be over $480,000 in the first year, over $34,000 in years two and four, and almost $200,000 in years three and five.

Fiscal implications are anticipated for certain local government entities in Bexar County and the DFW area. For Bexar County, changes to Subchapters A, B, C, E, and H would affect one electric-generating utility with three sites emitting or with the potential to emit 100 tpy or more NO_X. Increased costs for this utility would total approximately $3,000 per year for recordkeeping and reporting in years one through five. For the DFW area, two local governments, which have sources emitting or with the potential to emit between 25 tpy NO_X to 50 tpy NO_X, would be affected by changes proposed in Subchapters A and H. There would be increased costs associated with two diesel/oil fired engines that total over $20,000 in the first year, approximately $1,800 in years two and four, and over $14,000 in years three and five. Additionally, there would be increased costs associated with two process heaters that total over $90,000 in the first year and almost $1,500 per year in years two through five. Increased costs in the first year are attributed to capital purchases, and when applicable, variation in subsequent years is attributed to alternating testing requirements from year to year. The total cost estimate for local government, including entities in Bexar County and DFW counties is $113,000 in the first year, $6,300 in years two and four, and $18,500 in years three and five.

Public Benefits and Costs

Mr. Girten determined that for each year of the first five years the proposed rules are in effect, the public benefit anticipated will be compliance with federal law and continued protection of the environment and public health and safety combined with efficient and fair administration of NO_x emission standards for Bexar County, DFW counties, and HGB counties.

Cost savings are anticipated for entities with stationary diesel reciprocating internal combustion engines located at major or minor sources of NO_x in the HGB and DFW areas. Changes to Subchapter B and D would result in the removal of requirements for the monitoring of NO_x emissions using CEMS, and it would also provide for other more cost-effective methods for monitoring ammonia emissions. It is not possible to determine the number of affected entities, as these engines are used over a wide range of industry sectors, including but not limited to chemical plants, refineries, hospitals, educational institutions, and metal and forging foundries. New entities would no longer be responsible for capital costs associated with equipment purchase and installation for CEMS totaling approximately $150,000, and new and existing entities would no longer incur operation and maintenance costs totaling approximately $50,000 annually.

Costs would be incurred for affected businesses operating in Bexar County and the DFW area for implementation of requirements applicable to RACT. Revisions to Subchapters A, B, C, E, and H would apply RACT requirements to sources that emit 100 tpy or more NO_x in Bexar County. Revisions to Subchapters A and H would lower the threshold for major sources from 50 tpy NO_x to 25 tpy NO_x in the DFW area. The proposed rulemaking is not anticipated to increase any fees paid by businesses or industry.

In Bexar County, the rulemaking is anticipated to result in additional costs for one natural gas processing plant and cement kilns at two sites. The total cost for the natural gas processing plant, which has two engines and three turbines, is estimated at approximately $50,000 in the first year, $3,000 in years two and four, and over $35,000 in years three and five. Increased costs in the first year is attributed to initial purchases, and variation in subsequent years is attributed to alternating testing requirements from year to year. The total cost estimate for the cement kilns would total an estimated $400,000 to $800,000 for each of the first five years as necessary for the purchase of 19% aqueous ammonia for operation of a selective non-catalytic reduction system when needed. It is not certain as to how much of this reagent would be needed. For Bexar County, the total cost for all affected businesses totals between approximately $450,000 to $850,000 in the first year, and between over $400,000 and over $800,000 in years two through five.

In the DFW area, the rulemaking is anticipated to result in additional costs for 17 rich-burn engine units, one lean-burn engine unit, eight diesel/fuel oil fired engine units, nine boilers, 16 process heater units, six turbine units, seven brick kiln units, two incinerator units, and one furnace unit. The total cost estimate for rich-burn engines, which would each require non-selective catalytic reduction with an air-fuel ratio controller, is almost $500,000 in the first year, approximately $90,000 in years two and four, and almost $200,000 in years three and five. The total cost estimate for the lean-burn engine, which would require combustion modifications, is approximately $470,000 in the first year, approximately $1,700 in years two and four, and approximately $8,000 in years three and five. The total cost estimate for diesel/fuel oil fired engines, which would require initial purchase and installation of a fuel flow meter, is approximately $80,000 in the first year, $7,000 in years two and four, and approximately $55,000 in years three and five. The total cost estimate for boilers, which would require low NO_X burners, is approximately $650,000 in the first year, and over $10,000 in years two through five. The total cost estimate for process heaters, which would require dry low-NO_X (DLN) combustors along with initial demonstration testing, is approximately $750,000 in the first year, and over $11,000 in years two through five. The total cost estimate for turbines, some of which would require DLN combustors and others which may require different controls, is between $1.1 million to $2.7 million in the first year, and between $3,500 to $6,000 in years two through five. The total cost estimate for brick kilns, which require initial purchase and installation of a fuel flow meter, is approximately $70,000 in the first year, and $2,000 in years two through five. The total cost estimate for incinerators, which require initial purchase and installation of a fuel flow meter along with stack testing, is approximately $22,000 in the first year, and $2,000 in years two through five. The total cost estimate for the furnace, which require initial purchase and installation of a fuel flow meter along with stack testing, is approximately $11,000 in the first year, and $1,000 in years two through five. For the DFW area, the total cost for all affected businesses totals between approximately $3.6 million to $5.3 million in the first year, approximately $130,000 in years two and four, and over $290,000 in years three and five.

Local Employment Impact Statement

The commission reviewed this proposed rulemaking and determined that a Local Employment Impact Statement is not required because the proposed rulemaking does not adversely affect a local economy in a significant way for the first five years that the proposed rule is in effect.

Rural Communities Impact Assessment

The commission reviewed this proposed rulemaking and determined that the proposed rulemaking does not adversely affect rural communities differently than larger communities for the first five years that the proposed rules are in effect. Two affected sources in Bexar County are in a rural community, and 22 major sources in the DFW area are near a city with a population less than 25,000. The proposed rulemaking contains necessary requirements to meet requirements of the FCAA.

Small Business and Micro-Business Assessment

No adverse fiscal implications are anticipated for small or micro-businesses due to the implementation or administration of the proposed rule for the first five-year period the proposed rules are in effect. No small businesses were identified in Bexar County that would be subject to the rules and three to seven businesses in the DFW area may qualify as small businesses. No businesses were identified in either county which are classified as micro-businesses.

Small Business Regulatory Flexibility Analysis

The commission reviewed this proposed rulemaking and determined that a Small Business Regulatory Flexibility Analysis is not required because the proposed rule does not adversely affect a small or micro-business in a material way for the first five years the proposed rules are in effect. This rulemaking incorporates RACT requirements which factors in technological and economic feasibility, and small businesses are required to comply with the same criteria and provisions as larger firms to satisfy FCAA requirements. It is ultimately anticipated that the effects of the proposed rules on small businesses or micro-businesses are largely proportional to their effects on larger businesses.

Government Growth Impact Statement

The commission prepared a Government Growth Impact Statement assessment for this proposed rulemaking. The proposed rulemaking does not create or eliminate a government program and will not require an increase or decrease in future legislative appropriations to the agency. The proposed rulemaking does not require the creation of new employee positions, eliminate current employee positions, nor require an increase or decrease in fees paid to the agency. The proposed rulemaking amends an existing regulation, and it does not increase or decrease the number of individuals subject to its applicability. During the first five years, the proposed rule should not impact positively or negatively the state's economy.

Draft Regulatory Impact Analysis

The commission reviewed the proposed rulemaking in light of the regulatory impact analysis requirements of Texas Government Code, §2001.0225, and determined that the proposed rulemaking does not meet the definition of a major environmental rule as defined in that statute, and in addition, if it did meet the definition, would not be subject to the requirement to prepare a regulatory impact analysis. A major environmental rule means a rule, the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure, and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. Additionally, the proposed rulemaking does not meet any of the four applicability criteria for requiring a regulatory impact analysis for a major environmental rule, which are listed in Tex. Gov't Code Ann., § 2001.0225(a). Section 2001.0225 of the Texas Government Code 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 specific intent of these proposed rules is to comply with federal requirements for the implementation of control strategies necessary to attain and maintain the NAAQS for ozone mandated by 42 USC, 7410, FCAA, §110, and required to be included in operating permits by 42 USC, §7661a, FCAA, §502, as specified elsewhere in this preamble. The proposed rule addresses RACT requirements for the Bexar County 2015 eight-hour ozone nonattainment area and the DFW 2008 eight-hour ozone nonattainment area as well as revisions to existing rules to remove specific monitoring requirements and adjust ammonia emission limits for certain engines as discussed elsewhere in this preamble. States are required to adopt SIPs with enforceable emission limitations and other control measures, means, or techniques, as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of the FCAA. As discussed in the FISCAL NOTE portion of this preamble, the proposed rules are not anticipated to add any significant additional costs to affected individuals or businesses beyond what is necessary to attain the ozone NAAQS on the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

If a state does not comply with its obligations under 42 USC, §7410, FCAA, §110 to submit SIPs, states are subject to discretionary sanctions under 42 USC, §7410(m) or mandatory sanctions under 42 USC, §7509, FCAA, §179; as well as the imposition of a federal implementation plan (FIP) under 42 USC, §7410, FCAA, §110(c). Under 42 USC, §7661a, FCAA, §502, states are required to have federal operating permit programs that provide authority to issue permits and assure compliance with each applicable standard, regulation, or requirement under the FCAA, including enforceable emission limitations and other control measures, means, or techniques, which are required under 42 USC, §7410, FCAA, §110. Similar to requirements in 42 USC, §7410, FCAA, §110, states are not free to ignore requirements in 42 USC, §7661a, FCAA, §502 and must develop and submit programs to provide for operating permits for major sources that include all applicable requirements of the FCAA. Lastly, states are also subject to the imposition of sanctions under 42 USC, §7661a(d) and (i), FCAA, §502(d) and (i) for failure to submit an operating permits program, the disapproval of any operating permits program, or failure to adequately administer and enforce the approved operating permits program.

The requirement to provide a fiscal analysis of regulations in the Texas Government Code was amended by Senate Bill (SB) 633 during the 75th legislative session in 1997. The intent of SB 633 was to require agencies to conduct a regulatory impact analysis of extraordinary rules. These are identified in the statutory language as major environmental rules that will have a material adverse impact and will exceed a requirement of state law, federal law, or a delegated federal program, or are adopted solely under the general powers of the agency. With the understanding that this requirement would seldom apply, the commission provided a cost estimate for SB 633 that concluded "based on an assessment of rules adopted by the agency in the past, it is not anticipated that the bill will have significant fiscal implications for the agency due to its limited application." The commission also noted that the number of rules that would require assessment under the provisions of the bill was not large. This conclusion was based, in part, on the criteria set forth in the bill that exempted rules from the full analysis unless the rule was a major environmental rule that exceeds a federal law. Because of the ongoing need to meet federal requirements, the commission routinely proposes and adopts rules incorporating or designed to satisfy specific federal requirements. The legislature is presumed to understand this federal scheme. If each rule proposed by the commission to meet a federal requirement was considered to be a major environmental rule that exceeds federal law, then each of those rules would require the full regulatory impact analysis (RIA) contemplated by SB 633. Requiring a full RIA for all federally required rules is inconsistent with the conclusions reached by the commission in its cost estimate and by the Legislative Budget Board (LBB) in its fiscal notes.

Since the legislature is presumed to understand the fiscal impacts of the bills it passes, and that presumption is based on information provided by state agencies and the LBB, the that the intent of SB 633 was only to require the full RIA for rules that are extraordinary in nature. While the proposed rules may have a broad impact, that impact is no greater than is necessary or appropriate to meet the requirements of the FCAA, and in fact creates no additional impacts since the proposed rules do not impose burdens greater than required to demonstrate attainment of the ozone NAAQS as discussed elsewhere in this preamble. For these reasons, the proposed rules fall under the exception in Texas Government Code, §2001.0225(a), because they are required by, and do not exceed, federal law.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code, but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." (*Central Power & Light Co. v. Sharp*, 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Dudney v. State Farm Mut. Auto Ins. Co.*, 9 S.W.3d 884, 893 (Tex. App. Austin 2000); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App. Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).) The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance" (Texas Government Code, §2001.035). The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard.

As discussed in this analysis and elsewhere in this preamble, the commission has substantially complied with the requirements of Texas Government Code, §2001.0225. The proposed rules implement the requirements of the FCAA as discussed in this analysis and elsewhere in this preamble. The proposed rules were determined to be necessary to attain the ozone NAAQS and are required to be included in permits under 42 USC, §7661a, FCAA, §502, and will not exceed any standard set by state or federal law. These proposed rules are not an express requirement of state law. The proposed rules do not exceed a requirement of a delegation agreement or a contract between state and federal government, as the proposed rules, if adopted by the commission and approved by EPA, will become federal law as part of the approved SIP required by 42 U.S.C. §7410, FCAA, §110. The proposed rules were not developed solely under the general powers of the agency but are authorized by specific sections of Texas Health and Safety Code, Chapter 382 (also known as the Texas Clean Air Act), and the Texas Water Code, which are cited in the STATUTORY AUTHORITY section of this preamble, including Texas Health and Safety Code, §§382.011, 382.012, and 382.017. Therefore, this proposed rulemaking action is not subject to the regulatory analysis provisions of Texas Government Code, §2001.0225(b).

The commission invites public comment regarding the Draft Regulatory Impact Analysis Determination during the public comment period. Written comments on the Draft Regulatory Impact Analysis Determination may be submitted to the contact person at the address listed under the Submittal of Comments section of this preamble.

Takings Impact Assessment

Under Texas Government Code, §2007.002(5), taking means a governmental action that affects private real property, in whole or in part or temporarily or permanently, in a manner that requires the governmental entity to compensate the private real property owner as provided by the Fifth and Fourteenth Amendments to the United States Constitution or §17 or §19, Article I, Texas Constitution; or a governmental action that affects an owner's private real property that is the subject of the governmental action, in whole or in part or temporarily or permanently, in a manner that restricts or limits the owner's right to the property that would otherwise exist in the absence of the governmental action; and is the producing cause of a reduction of at least 25 percent in the market value of the affected private real property, determined by comparing the market value of the property as if the governmental action is not in effect and the market value of the property determined as if the governmental action is in effect. The commission completed a takings impact analysis for the proposed rulemaking action under the Texas Government Code, §2007.043.

The primary purpose of this proposed rulemaking action, as discussed elsewhere in this preamble, is to meet federal requirements for the implementation of control strategies necessary to attain and maintain the NAAQS for ozone mandated by 42 USC, 7410, FCAA, §110, and required to be included in operating permits by 42 USC, §7661a, FCAA, §502. The proposed rule addresses RACT requirements for the Bexar County 2015 eight-hour ozone nonattainment area and the DFW 2008 eight-hour ozone nonattainment area as well as revisions to existing rules to remove specific monitoring requirements and adjust ammonia emission limits for certain engines as discussed elsewhere in this preamble.

States are required to adopt SIPs with enforceable emission limitations and other control measures, means, or techniques, as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of the FCAA. If a state does not comply with its obligations under 42 USC, §7410, FCAA, §110 to submit SIPs, states are subject to discretionary sanctions under 42 USC, §7410(m) or mandatory sanctions under 42 USC, §7509, FCAA, §179; as well as the imposition of a federal implementation plan (FIP) under 42 USC, §7410, FCAA, §110(c). Under 42 USC, §7661a, FCAA, §502, states are required to have federal operating permit programs that provide authority to issue permits and assure compliance with each applicable standard, regulation, or requirement under the FCAA, including enforceable emission limitations and other control measures, means, or techniques, which are required under 42 USC, §7410, FCAA, §110. Similar to requirements in 42 USC, §7410, FCAA, §110, regarding the requirement to adopt and implement plans to attain and maintain the national ambient air quality standards, states are not free to ignore requirements in 42 USC, §7661a, FCAA, §502 and must develop and submit programs to provide for operating permits for major sources that include all applicable requirements of the FCAA. Lastly, states are also subject to the imposition of sanctions under 42 USC, §7661a(d) and (i), FCAA, §502(d) and (i) for failure to submit an operating permits program, the disapproval of any operating permits program, or failure to adequately administer and enforce the approved operating permits program.

The proposed rules will not create any additional burden on private real property beyond what is required under federal law, as the proposed rules, if adopted by the commission and approved by EPA, will become federal law as part of the approved SIP required by 42 U.S.C. §7410, FCAA, §110. The proposed rules will not affect private real property in a manner that would require compensation to private real property owners under the United States Constitution or the Texas Constitution. The proposal also will not affect private real property in a manner that restricts or limits an owner's right to the property that would otherwise exist in the absence of the governmental action. Therefore, the proposed rulemaking will not cause a taking under Texas Government Code, Chapter 2007.

Consistency with the Coastal Management Program

The commission reviewed the proposed rulemaking and found that the proposal is subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act, Texas Natural Resources Code, §§33.201 *et seq.*, and therefore must be consistent with all applicable CMP goals and policies. The commission conducted a consistency determination for the proposed rules in accordance with Coastal Coordination Act Implementation Rules, 31 TAC §505.22 and found the proposed rulemaking is consistent with the applicable CMP goals and policies.

The proposed amendments are consistent with the applicable CMP goal expressed in 31 TAC §501.12(1) of protecting and preserving the quality and values of coastal natural resource areas, and the policy in 31 TAC §501.14(l), which requires that the commission protect air quality in coastal areas. The proposed rulemaking and SIP revision would ensure that the amendments comply with 40 CFR Part 50, National Primary and Secondary Air Quality Standards, and 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans.

Written comments on the consistency of this rulemaking may be submitted to the contact person at the address listed under the Submittal of Comments section of this preamble.

Effect on Sites Subject to the Federal Operating Permits Program

Chapter 117 is an applicable requirement under 30 TAC Chapter 122, Federal Operating Permits Program. If the proposed revisions to Chapter 117 are adopted, owners or operators subject to the federal operating permit program must, consistent with the revision process in Chapter 122, upon the effective date of the rulemaking, revise their operating permit to include the new Chapter 117 requirements.

Announcement of Hearing

The commission will hold an in-person public hearing on this proposal in Houston on Thursday January 4, 2024, at 7:00 p.m. at the Houston-Galveston Area Council (Conference Room), 3555 Timmons Ln #100, Houston, TX 77027; in San Antonio on Tuesday January 9, 2024, at 7:00 p.m. at the Alamo Area Council of Governments (Board Room), 2700 NE Loop 410, Suite 101, San Antonio, TX 78217; and in Arlington on Thursday January 11, 2024, at 7:00 p.m. at the Arlington City Council Chambers, 101 West Abrams Street, Arlington, TX 76010. The hearing is structured for the receipt of oral or written comments by interested persons. Individuals may present oral statements when called upon in order of registration. Open discussion will not be permitted during the hearing; however, commission staff members will be available to discuss the proposal 30 minutes prior to the hearing.

Persons who have special communication or other accommodation needs who are planning to attend the hearing should contact Sandy Wong, Office of Legal Services at (512) 239-1802 or 1-800-RELAY-TX (TDD). Requests should be made as far in advance as possible.

Submittal of Comments

Written comments may be submitted to Gwen Ricco, MC 205, Office of Legal Services, Texas

Commission on Environmental Quality, P.O. Box 13087, Austin, Texas 78711-3087, or faxed to *fax4808@tceq.texas.gov*. Electronic comments may be submitted at: https://tceq.commentinput.com/comment/search. File size restrictions may apply to comments being submitted via the TCEQ Public Comments system. All comments should reference Rule Project Number 2023-117-117-AI. The comment period closes on January 16, 2024. Please choose one of the methods provided to submit your written comments.

Copies of the proposed rulemaking can be obtained from the commission's website at *https://www.tceq.texas.gov/rules/propose_adopt.html*. For further information, please contact Lindley Anderson, Air Quality Division, at (512) 239-0003 or lindley.anderson@tceq.texas.gov.

SUBCHAPTER A: DEFINITIONS

§117.10

Statutory Authority

The amendments are proposed under Texas Water Code (TWC), §5.102, concerning general powers; §5.103, concerning Rules; TWC, §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; TWC, §7.002, concerning Enforcement Authority, which authorizes the commission to enforce the provisions of the Water Code and the Health and Safety Code within the commission's jurisdiction; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The amendments are also proposed under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; and THSC, §382.012, concerning the State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air.

The proposed amendments implement TWC, §§5.102, 5.103, 5.105 and 7.002; and THSC, §§382.002, 382.011, 382.012, 382.017.

§117.10. Definitions.

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

(1) Annual capacity factor--The total annual fuel consumed by a unit divided by the fuel that 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 under the 1990 Federal Clean Air Act Amendments.

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

<u>(B) Bexar County ozone nonattainment area--An area consisting of Bexar County.</u>

<u>(C)</u>[(B)] Dallas-Fort Worth eight-hour ozone nonattainment area--An area consisting of:

(i) for the purposes of Subchapter D of this chapter (relating to Combustion Control at Minor Sources in Ozone Nonattainment Areas), Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties; or

(ii) for all other divisions of this chapter, Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, Tarrant, and Wise Counties.

(D)[(C)] Houston-Galveston-Brazoria 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. An auxiliary steam boiler produces steam as a replacement for steam produced by another piece of equipment that is not operating due to planned or unplanned maintenance.

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

(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) Continuous emissions monitoring system (CEMS)--The total equipment necessary for the continuous determination and recordkeeping of process gas concentrations and emission rates in units of the applicable emission limitation.

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

(11) Diesel engine--A compression-ignited two- or four-stroke engine that liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition.

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

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

(14) Electric power generating system--One electric power generating system consists of either:

(A) for the purposes of Subchapter C, Divisions 1, 2, and 4 of this chapter (relating to Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources; Bexar County Ozone Nonattainment Area Utility Electric Generation Sources; and Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources), all boilers, auxiliary steam boilers, and stationary gas turbines (including duct burners used in turbine exhaust ducts) at electric generating facility (EGF) accounts that generate electric energy for compensation; are owned or operated by an electric cooperative, municipality, river authority, public utility, independent power producer, or a Public Utility Commission of Texas regulated utility, or any of its successors; and are entirely located in one of the following ozone nonattainment areas:

(i) Beaumont-Port Arthur; [or]

(ii) Bexar County; or

(iii)[(ii)] Dallas-Fort Worth eight-hour;

(B) for the purposes of Subchapter C, Division 3 of this chapter (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources), all boilers, auxiliary steam boilers, and stationary gas turbines (including duct burners used in turbine exhaust ducts) at EGF accounts that generate electric energy for compensation; are owned or operated by an electric cooperative, municipality, river authority, public utility, or a Public Utility Commission of Texas regulated utility, or any of its successors; and are entirely located in the Houston-Galveston-Brazoria ozone nonattainment area;

(C) for the purposes of Subchapter B, Division 3 of this chapter (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources), all units in the Houston-Galveston-Brazoria ozone nonattainment area that generate electricity but do not meet the conditions specified in subparagraph (B) of this paragraph, including, but not limited to, cogeneration units and units owned by independent power producers; or

(D) for the purposes of Subchapter E, Division 1 of this chapter (relating to Utility Electric Generation in East and Central Texas), all boilers, auxiliary steam boilers, and stationary gas turbines at EGF accounts that generate electric energy for compensation; are owned or operated by an electric cooperative, independent power producer, municipality, river authority, or public utility, or any of its successors; and are located in Atascosa, Bastrop, [Bexar,] Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, or Wharton County, or in Bexar County until December 31, 2024.

(15) Emergency situation--As follows.

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

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

(ii) the period of time that an Electric Reliability Council of Texas, Inc. (ERCOT)-issued emergency notice or energy emergency alert (EEA) (as defined in *ERCOT Nodal Protocols, Section 2: Definitions and Acronyms* (August 13, 2014) and issued as specified in *ERCOT Nodal Protocols, Section 6: Adjustment Period and Real-Time Operations* (August 13, 2014)) is applicable to the serving electric power generating system. The emergency situation is considered to end upon expiration of the emergency notice or EEA issued by ERCOT;

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

(iv) an unforeseen failure of natural gas service;

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

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

(vii) operation of an emergency generator as part of ERCOT's emergency response service (as defined in *ERCOT Nodal Protocols, Section 2: Definitions and Acronyms* (August 13, 2014)) if the operation is in direct response to an instruction by ERCOT during the period of an ERCOT EEA as specified in clause (ii) of this subparagraph.

(B) An emergency situation does not include:

(i) operation for training purposes or other foreseeable events; or

(ii) operation for purposes of supplying power for distribution to the electric grid, except as specified in subparagraph (A)(vii) of this paragraph.

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

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

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

(19) 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 per hour per cubic foot.

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

(21) Incinerator--As follows.

(A) For the purposes of this chapter, the term "incinerator" includes both of the following:

(i) a control device that combusts or oxidizes gases or vapors (e.g., thermal oxidizer, catalytic oxidizer, vapor combustor); and

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

(B) The term "incinerator" does not apply to boilers or process heaters as defined in this section, or to flares as defined in §101.1 of this title.

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

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

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

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

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

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

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

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

(28) Low heat release rate--A ratio of boiler design heat input to firebox volume less than 70,000 British thermal units per hour per cubic foot.

(29) 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;

<u>(B) at least 100 tpy of NO_x and is located in the Bexar County ozone nonattainment area;</u>

<u>(C)</u>[(B)] at least <u>25</u>[50] tpy of NO_x and is located in the Dallas-Fort Worth eight-hour ozone nonattainment area;

<u>(D)</u>[(C)] at least 25 tpy of NO_x and is located in the Houston-Galveston-Brazoria ozone nonattainment area; or

(E)[(D)] the amount specified in the major source definition contained in the Prevention of Significant Deterioration of Air Quality regulations promulgated by the United States Environmental Protection Agency in 40 Code of Federal Regulations §52.21 as amended June 3, 1993 (effective June 3, 1994), and is located in Atascosa, Bastrop, [Bexar,] Brazos, Calhoun, Cherokee, Comal, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Hays, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Red River, Robertson, Rusk, Titus, Travis, Victoria, or Wharton County or in Bexar County until December 31, 2024.

(30) Maximum rated capacity--The maximum design heat input, expressed in million British thermal units per hour, 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 must 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 must 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 must be used as the maximum rated capacity, unless limited by permit condition to a lesser heat input, in which case the limiting condition must be used as the maximum rated capacity; or

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

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

(32) Nitric acid--Nitric acid that is 30% to 100% in strength.

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

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

(35) Parts per million by volume (ppmv)--All ppmv emission specifications specified in this chapter are referenced on a dry basis. When required to adjust pollutant concentrations to a specified oxygen (O_2) correction basis, the following equation must be used.

Figure: 30 TAC §117.10(35) (No change)

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

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

(38) Plant-wide emission specification--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.

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

(40) Process heater--Any combustion equipment fired with liquid and/or gaseous fuel that is used to transfer heat from combustion gases to a process fluid, superheated steam, or water for the purpose of heating the process fluid or causing a chemical reaction. The term "process heater" does not apply to any unfired waste heat recovery heater that is used to

recover sensible heat from the exhaust of any combustion equipment, or to boilers as defined in this section.

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

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

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

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

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

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

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

(48) System-wide emission specification--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 must be used in lieu of maximum rated capacities for the purpose of calculating the system-wide emission specification.

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

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

(51) Unit--A unit consists of either:

(A) for the purposes of §§117.105, 117.305, 117.405, 117.1005, and 117.1205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) and each requirement of this chapter associated with §§117.105, 117.305, 117.405, 117.1005, and 117.1205 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section;

(B) for the purposes of §§117.110, 117.310, 117.1010, and 117.1210 of this title (relating to Emission Specifications for Attainment Demonstration) and each requirement of this chapter associated with §§117.110, 117.310, 117.1010, and 117.1210 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section, or any other stationary source of nitrogen oxides (NO_x) at a major source, as defined in this section;

(C) for the purposes of §117.2010 of this title (relating to Emission Specifications) and each requirement of this chapter associated with §117.2010 of this title, any boiler, process heater, stationary gas turbine (including any duct burner in the turbine exhaust duct), or stationary internal combustion engine, as defined in this section;

(D) for the purposes of §117.2110 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) and each requirement of this chapter associated with §117.2110 of this title, any stationary internal combustion engine, as defined in this section;

(E) for the purposes of §117.3310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) and each requirement of this chapter associated with §117.3310 of this title, any stationary internal combustion engine, as defined in this section; [or]

(F) for the purposes of §117.410 and §117.1310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) and each requirement of this chapter associated with §117.410 and §117.1310 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section, or any other stationary source of NO_x at a major source, as defined in this section; [.]

(G) for the purposes of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) and each requirement of this chapter associated with §117.205 of this title, any stationary gas turbine (including any duct burner used in the turbine exhaust duct) or gas-fired lean-burn stationary reciprocating internal combustion engine, as defined in this section; or

(H) for the purposes of §117.1105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) and each requirement of this chapter associated with §117.1105 of this title, any utility boiler, auxiliary steam boiler, or stationary gas turbine (including any duct burner used in turbine exhaust ducts), as defined in this section.

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

(53) 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.

SUCHAPTER B: COMBUSTION CONTROL AT MAJOR INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 2: BEXAR COUNTY OZONE NONATTAINMENT AREA MAJOR SOURCES

§§117.200, 117.203, 117.205, 117.230, 117.235, 117.240, 117.245, 117.252

Statutory Authority

The new rules are proposed under Texas Water Code (TWC), §5.102, concerning general powers; §5.103, concerning Rules; TWC, §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; TWC, §7.002, concerning Enforcement Authority, which authorizes the commission to enforce the provisions of the Water Code and the Health and Safety Code within the commission's jurisdiction; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new rules are also proposed under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning the State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants; and THSC, §382.021, concerning Sampling Methods and Procedures.

The proposed new rules implement TWC, §§5.102, 5.103 and 7.002; and THSC, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.021.

§117.200. Applicability.

This division applies to the following units located at any major stationary source of nitrogen oxides located in the Bexar County ozone nonattainment area:

(1) stationary gas turbines;

(2) duct burners used in turbine exhaust ducts; and

(3) gas-fired lean-burn stationary reciprocating internal combustion engines.

§117.203. Exemptions.

The following units are exempt from this division, except as specified in §§117.240(f), 117.245(f)(4) and (9), and 117.252 of this title (relating to Continuous Demonstration of Compliance; Notification, Recordkeeping, and Reporting Requirements; and Control Plan Procedures for Reasonably Available Control Technology (RACT)):

(1) stationary gas turbines and gas-fired lean-burn stationary reciprocating internal combustion engines that are used as follows:

(A) in research and testing of the unit;

(B) for purposes of performance verification and testing of the unit;

(C) solely to power other gas turbines or engines during startups;

(D) exclusively in emergency situations, except that operation for testing or maintenance purposes of the gas turbine or engine is allowed for up to 100 hours per year, based on a rolling 12-month basis; or

(E) in response to and during the existence of any officially declared disaster or state of emergency;

(2) gas-fired lean-burn stationary reciprocating internal combustion engines with a horsepower (hp) rating less than 50 hp;

(3) stationary gas turbines with a maximum rated capacity less than 10.0 million British thermal units per hour; and

(4) units located at a major source that is subject to Subchapter C, Division 2 of this chapter (related to Bexar County Ozone Nonattainment Area Utility Electric Generation Sources).

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

(a) Emission specifications. No person shall allow the discharge into the atmosphere nitrogen oxides (NO_X) emissions in excess of the following emission specifications, in accordance with the applicable schedule in §117.9010 of this title (relating to Compliance Schedule for Bexar County Ozone Nonattainment Area Major Sources), except as provided in subsection (c) of this section:

(1) stationary gas turbines, 0.55 pound per million British thermal unit (lb/MMBtu);

(2) duct burners used in turbine exhaust ducts, 0.55 lb/MMBtu; and

(3) gas-fired lean-burn stationary reciprocating internal combustion engines, 0.5 gram per horsepower-hour.

(b) NO_X averaging time. The emission specifications in subsection (a) of this section apply on:

(1) a block one-hour average, in the units of the applicable standard; or

(2) if the unit is operated with a NO_X continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.240 of this title (relating to Continuous Demonstration of Compliance), a rolling 30-day average, in the units of the applicable standard.

(c) Compliance flexibility. An owner or operator may use §117.9800 of this title (relating to Use of Emission Credits for Compliance) to comply with the NO_x emission specifications of this section.

(d) Prohibition of circumvention.

(1) The maximum rated capacity used to determine the applicability of the emission specifications in this section and the initial compliance demonstration, monitoring, testing requirements, and control plan requirements in §§117.235, 117.240, and 117.252 of this title (relating to Initial Demonstration of Compliance; Continuous Demonstration of Compliance; and Control Plan Procedures for Reasonably Available Control Technology) must be the greater of the following:

(A) the maximum rated capacity as of December 31, 2019;

(B) the maximum rated capacity after December 31, 2019; or

(C) the maximum rated capacity authorized by a permit issued under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) after December 31, 2019.

(2) A unit's classification is determined by the most specific classification applicable to the unit as of December 31, 2019. For example, a unit that is classified as a gas-fired lean-burn stationary reciprocating internal combustion engine as of December 31, 2019, but subsequently is authorized to operate as a dual-fuel engine, is classified as a gas-fired lean-burn stationary reciprocating internal combustion engine for the purposes of this chapter.

(3) A source that met the definition of major source on December 31, 2019, is always classified as a major source for purposes of this chapter. A source that did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2019, but becomes a major source at any time after December 31, 2019, is from that time forward always classified as a major source for purposes of this chapter.

§117.230. Operating Requirements.

All units subject to the emission specifications in §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) must be operated to minimize nitrogen oxides (NO_X) emissions, consistent with the emission control techniques selected, over the unit's operating or load range during normal operations. Such operational requirements include the following.

(1) Each unit controlled with post-combustion control techniques must 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.

(2) Each gas-fired lean-burn stationary reciprocating internal combustion engine must be checked for proper operation of the engine according to §117.8140(b) of this title (relating to Emission Monitoring for Engines).

§117.235. Initial Demonstration of Compliance.

(a) The owner or operator of any unit subject to §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) shall test the unit for nitrogen oxides (NO_X) and oxygen (O_2) emissions while firing gaseous fuel or, as applicable, liquid and solid fuel.

(b) Initial demonstration of compliance testing must be performed in accordance with the schedule specified in §117.9010 of this title (relating to Compliance Schedule for Bexar County Ozone Nonattainment Area Major Sources).

(c) The initial demonstration of compliance tests required by subsection (a) of this section must use the methods referenced in subsection (e) or (f) of this section and must be used for determination of initial compliance with the emission specifications of this division. Test results must be reported in the units of the applicable emission specifications and averaging periods.

(d) Any continuous emissions monitoring system (CEMS) or any predictive emissions monitoring system (PEMS) required by §117.240 of this title (relating to Continuous Demonstration of Compliance) must be installed and operational before conducting testing under subsection (a) of this section. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system.

(e) For units operating without CEMS or PEMS, compliance with the emission specifications of this division must be demonstrated according to the requirements of

§117.8000 of this title (relating to Stack Testing Requirements).

(f) For units operating with CEMS or PEMS in accordance with §117.240 of this title, initial compliance with the emission specifications of this division must be demonstrated after monitor certification testing using the CEMS or PEMS. For units complying with a NO_x emission specification on a block one-hour average, every 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 specification.

(g) Compliance stack test reports must include the information required in §117.8010 of this title (relating to Compliance Stack Test Reports).

§117.240. Continuous Demonstration of Compliance.

(a) Totalizing fuel flow meters.

(1) The owner or operator of units subject to this division shall install, calibrate, maintain, and operate a totalizing fuel flow meter, with an accuracy of ± 5%, to individually and continuously measure the gas and liquid fuel usage. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The owner or operator must continuously operate the totalizing fuel flow meter at least 95% of the time when the unit is operating during a calendar year. For the purpose of compliance with this subsection for units having pilot fuel supplied by a separate fuel system or from an unmonitored portion of the same fuel system, the fuel flow to pilots may be calculated using the manufacturer's

design flow rates rather than measured with a fuel flow meter. The calculated pilot fuel flow rate must be added to the monitored fuel flow when fuel flow is totaled.

(2) The following are alternatives to the fuel flow monitoring requirements of this subsection.

(A) Units operating with a nitrogen oxides (NO_X) and diluent continuous emissions monitoring system (CEMS) under subsection (c) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (CFR) Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

(B) Units that vent to a common stack with a NO_X and diluent CEMS under subsection (c) of this section may use a single totalizing fuel flow meter.

(C) Gas-fired lean-burn stationary reciprocating internal combustion engines and gas turbines equipped with a continuous monitoring system that continuously monitors horsepower and hours of operation are not required to install totalizing fuel flow meters. The continuous monitoring system must be installed, calibrated, maintained, and operated according to manufacturers' recommended procedures.

(b) NO_X monitors.

(1) The owner or operator of the following units shall install, calibrate, maintain, and operate a CEMS or predictive emissions monitoring system (PEMS) to monitor exhaust NO_X:

(A) units with a rated heat input greater than or equal to 100 million British thermal units (MMBtu) per hour;

(B) stationary gas turbines with a megawatt (MW) rating greater than or equal to 30 MW and operated more than 850 hours per year;

(C) units that use a chemical reagent for reduction of NO_X; and

(D) units that the owner or operator elects to comply with the NO_X emission specifications of §117.205(a) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) using a pound per MMBtu limit on a 30-day rolling average.

(2) Units subject to the NO_X CEMS requirements of 40 CFR Part 75 are not required to install CEMS or PEMS under this subsection.

(3) The owner or operator shall use one of the following methods to provide substitute emissions compliance data during periods when the NO_X monitor is off-line:

(A) if the NO_X monitor is a CEMS:

(i) subject to 40 CFR Part 75, use the missing data procedures specified in 40 CFR Part 75, Subpart D (Missing Data Substitution Procedures); or

(ii) subject to 40 CFR Part 75, Appendix E, use the missing data procedures specified in 40 CFR Part 75, Appendix E, §2.5 (Missing Data Procedures);

(B) if the NO_x monitor is a PEMS:

(i) use the methods specified in 40 CFR Part 75, Subpart D; or

(ii) use calculations in accordance with §117.8110(b) of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources);

(C) monitor operating parameters for each unit in accordance with 40 CFR Part 75, Appendix E, §1.1 or §1.2 and calculate NO_x emission rates based on those procedures; or

(D) use the maximum block one-hour emission rate as measured during the initial demonstration of compliance required in §117.235(e) of this title (relating to Initial Demonstration of Compliance).

(c) CEMS requirements. The owner or operator of any CEMS used to meet a pollutant monitoring requirement of this section shall comply with the requirements of §117.8100(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources).

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

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

(2) The PEMS must meet the requirements of §117.8100(b) of this title.

(e) Engine monitoring. The owner or operator of any gas-fired lean-burn stationary reciprocating internal combustion engine subject to the emission specifications of this division shall stack test engine NO_X emissions as specified in §117.8140(a) of this title (relating to Emission Monitoring for Engines).

(f) Run time meters. The owner or operator of any stationary gas turbine or gas-fired lean-burn stationary reciprocating internal combustion engine claimed exempt using the exemption of §117.203(1)(D) of this title (relating to Exemptions) shall record the operating time with a non-resettable elapsed run time meter.

(g) Data used for compliance. After the initial demonstration of compliance required by §117.235 of this title, the methods required in this section must be used to determine compliance with the emission specifications of §117.205(a) of this title. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the unit is in compliance with applicable emission specifications.

(h) Testing requirements.

(1) The owner or operator of units that are subject to the emission specifications of §117.205(a) of this title shall test the units as specified in §117.235 of this title in accordance with the applicable schedule specified in §117.9010 of this title (relating to Compliance Schedule for Bexar County Eight-Hour Ozone Nonattainment Area Major Sources).

(2) The owner or operator of any unit not equipped with CEMS or PEMS that are subject to the emission specifications of §117.205(a) of this title shall retest the unit as specified in §117.235 of this title within 60 days after any modification that could reasonably be expected to increase the NO_x emission rate.

§117.245. Notification, Recordkeeping, and Reporting Requirements.

(a) Startup and shutdown records. For units subject to the startup and/or shutdown provisions of §101.222 of this title (relating to Demonstrations), hourly records must be made of startup and/or shutdown events and maintained for a period of at least two years. Records must be available for inspection by the executive director, the United States Environmental Protection Agency, and any local air pollution control agency having jurisdiction upon request. These records must 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 a unit subject to the emission specifications of §117.205(a) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) shall submit written notification of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) relative accuracy test audit (RATA) conducted under §117.240 of this title (relating to Continuous Demonstration of

Compliance) or any testing conducted under §117.235 of this title (relating to Initial Demonstration of Compliance) at least 15 days in advance of the date of the RATA or testing to the appropriate regional office and any local air pollution control agency having jurisdiction.

(c) Reporting of test results. The owner or operator of a unit subject to the emission specifications of §117.205(a) of this title shall furnish the Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction a copy of any testing conducted under §117.235 of this title and any CEMS or PEMS RATA conducted under §117.240 of this title:

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

(2) not later than the compliance schedule specified in §117.9010 of this title (relating to Compliance Schedule for Bexar County Eight-Hour Ozone Nonattainment Area Major Sources).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS or PEMS under §117.240 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission specifications of this division and the monitoring system performance. All reports must be postmarked or received by the 30th day following the end of each calendar semiannual period (i.e., July 30 and January 30). Written reports must include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations §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;

(2) specific identification of each period of excess emissions that occurs during startups, 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 when 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 must be stated in the report; and

(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 or PEMS 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) must 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 unit operating time for the reporting period or the CEMS or PEMS downtime for the reporting period is greater than or equal to 5.0% of the total unit operating time for the reporting period, a summary report and an excess emission report must both be submitted.

(e) Reporting for engines. The owner or operator of any gas-fired engine subject to the emission specifications in §117.205 of this title shall report in writing to the executive director on a semiannual basis any excess emissions and the air-fuel ratio monitoring system performance. All reports must be postmarked or received by the 30th day following the end of each calendar semiannual period (i.e., July 30 and January 30). Written reports must include the following information:

(1) the magnitude of excess emissions (based on the quarterly emission checks of §117.230(a)(2) of this title (relating to Operating Requirements) and the biennial emission testing required for demonstration of emissions compliance in accordance with §117.240(e) of this title), computed in pounds per hour and grams per horsepower-hour, any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the engine operating time during the reporting period; and

(2) specific identification, to the extent feasible, of each period of excess emissions that occurs during startups, 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 must be kept for a period of at least five years and must be made available upon request by authorized representatives of the executive director, the United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction.

The records must include:

(1) for each unit subject to §117.240(a) of this title, records of annual fuel usage;

(2) for each unit using a CEMS or PEMS in accordance with §117.240 of this title, monitoring records of:

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

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

(i) pounds per million British thermal units (lb/MMBtu) heat input; and

(ii) pounds or tons per day;

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

(A) emissions measurements required by:

(i) §117.230(2) of this title; and

(ii) §117.240(e) of this title;

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

(C) daily average horsepower and total daily hours of operation for each engine that the owner or operator elects to use the alternative monitoring system allowed under §117.240(a)(2)(C) of this title;

(4) for units claimed exempt from emission specifications using the exemption of §117.203(1)(D) of this title (relating to Exemptions), records of monthly hours of operation, for exemptions based on hours per year of operation. In addition, for each turbine or engine claimed exempt under §117.203(1)(D) or (E) of this title, written records must be maintained of the purpose of turbine or engine operation and, if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation;

(5) records of the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS or PEMS; and

(6) records of the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.235 of this title.

§117.252. Control Plan Procedures for Reasonably Available Control Technology.

(a) The owner or operator of any unit subject to §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) at a major source of nitrogen oxides (NO_x) shall maintain a control plan report to show compliance with the requirements of §117.205 of this title. The report must include:

(1) a list of all units that are subject to §117.205 of this title. The list must include for each unit:

(A) the facility identification number and emission point number as submitted to the Emissions Assessment Section of the commission; and

(B) the emission point number as listed on the Maximum Allowable Emissions Rate Table of any applicable commission permit;

(C) the maximum rated capacity;

(D) the method of NO_x control for each unit;

(E) the emissions measured by testing required in §117.235 of this title (relating to Initial Demonstration of Compliance);

(F) the compliance stack test report or monitor certification report required by §117.235 of this title; and

(G) the use of any compliance flexibility in accordance with §117.9800 of this title (relating to Use of Emission Credits for Compliance); and

(2) a list of all units with a claimed exemption from the emission specification of §117.205 of this title and the specific rule citation claimed as the basis for that exemption.

(b) The report must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Office of Air by the applicable date specified for control plans in §117.9010 of this title (relating to Compliance Schedule for Bexar County Major Sources).

(c) For any unit that becomes subject to §117.205 of this title after the applicable date specified for control plans in §117.9010 of this title, the control plan must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Office of Air no later than 60 days after becoming subject.

(d) If any of the information changes in a control plan report submitted in accordance with subsection (b) or (c) of this section, including functionally identical replacements, the control plan must be updated no later than 60 days after the change occurs. Written or electronic records of the updated control plan must be kept for a period of at least five years and must be made available upon request by authorized representatives of the executive director, the United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction.

SUBCHAPTER B: COMBUSTION CONTROL AT MAJOR INDUSTRIAL COMMERCIAL, AND INSTITUTIONAL SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 3: HOUSTON-GALVESTON-BRAZORIA OZONE NONATTAINMENT AREA MAJOR SOURCES

§§117.310, 117.340

Statutory Authority

The amended rules are proposed under Texas Water Code (TWC), §5.102, concerning general powers; §5.103, concerning Rules; TWC, §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; TWC, §7.002, concerning Enforcement Authority, which authorizes the commission to enforce the provisions of the Water Code and the Health and Safety Code within the commission's jurisdiction; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The amendments are also proposed under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning the State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants; and THSC, §382.021, concerning Sampling

Methods and Procedures.

The proposed amendments implement TWC, §§5.102, 5.103 and 7.002; and THSC, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.021.

§117.310. Emission Specifications for Attainment Demonstration.

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

(1) gas-fired boilers:

(A) with a maximum rated capacity equal to or greater than 100 million British thermal units per hour (MMBtu/hr), 0.020 pounds per million British thermal units (lb/MMBtu);

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

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

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

(A) 40 ppmv NO_X at 0.0% O_2, dry basis;

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

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

(i) install and certify a NO_X CEMS or PEMS as specified in §117.340(f) or (g) of this title (relating to Continuous Demonstration of Compliance) no later than June 30, 2001;

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

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

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

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

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

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

(i) 0.030 lb/MMBtu; or

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

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

(5) wood fuel-fired boilers, 0.060 lb/MMBtu;

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

(7) liquid-fired boilers, 2.0 pounds per 1,000 gallons of liquid burned;

(8) process heaters:

(A) other than pyrolysis reactors:

(i) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, 0.025 lb/MMBtu; and

(ii) with a maximum rated capacity less 40 MMBtu/hr, 0.036 lb/MMBtu (or alternatively, 30 ppmv NO_X, at 3.0% O_2, dry basis); and

(B) pyrolysis reactors, 0.036 lb/MMBtu;

(9) stationary, reciprocating internal combustion engines:

(A) gas-fired rich-burn engines:

(i) fired on landfill gas, 0.60 grams per horsepower-hour (g/hp-hr); and

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

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

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

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

(C) dual-fuel engines:

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

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

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

(E) for diesel engines, excluding dual-fuel engines, not subject to subparagraph (D) of this paragraph:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(10) stationary gas turbines:

(A) rated at 10.0 megawatts (MW) or greater, 0.032 lb/MMBtu;

(B) rated at 1.0 MW or greater, but less than 10.0 MW, 0.15 lb/MMBtu; and

(C) rated at less than 1.0 MW, 0.26 lb/MMBtu;

(11) duct burners used in turbine exhaust ducts, the corresponding gas turbine emission specification of paragraph (10) of this subsection;

(12) pulping liquor recovery furnaces, either:

(A) 0.050 lb/MMBtu; or

(B) 1.08 pounds per air-dried ton of pulp;

(13) kilns:

(A) lime kilns, 0.66 pounds per ton of calcium oxide; and

(B) lightweight aggregate kilns, 1.25 pounds per ton of product;

(14) metallurgical furnaces:

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

(B) reheat furnaces, 0.062 lb/MMBtu;

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

(16) incinerators, either of the following:

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

(B) 0.030 lb/MMBtu; and

(17) as an alternative to the emission specifications in paragraphs (1) - (16) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu. For units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor must be used to determine whether the unit is eligible for the emission specification of this paragraph. For units placed into service after January 1, 1997, the annual capacity factor must be calculated from two consecutive years in the first five years of operation to determine whether the unit is eligible for the emission specification of this paragraph, using the same two consecutive years chosen for the activity level baseline. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title (relating to Definitions).

(b) NO_X averaging time. The averaging time for the emission specifications of subsection (a) of this section must be as specified in Chapter 101, Subchapter H, Division 3 of this title, except that electric generating facilities (EGFs) must also comply with the daily and 30-day system cap emission limitations of §117.320 of this title (relating to System Cap).

(c) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to subsection (a) of this section, emissions in excess of the following, except as provided in §117.325 of this title (relating to Alternative Case Specific Specifications) or paragraph (3) or (4) of this subsection.

(1) CO emissions must not exceed 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines; or 775 ppmv at 7.0% O_2, dry basis for wood fuel-fired boilers or process heaters):

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

(B) on a one-hour average, for units not equipped with CEMS or PEMS for CO.

(2) For units that inject urea or ammonia into the exhaust stream for NO_X control, ammonia emissions must not exceed 10 ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), gas-fired lean-burn engines, [and] lightweight aggregate kilns, and diesel engines; 0.0% O_2, dry, for fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents); 7.0% O_2, dry, for BIF units that were regulated as existing facilities in 40 CFR Part 266, Subpart H (as was in effect on June 9, 1993), wood-fired boilers, and incinerators; and 3.0% O_2, dry, for all other units, based on:

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

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

(3) The correction of CO emissions to 3.0% O_2, dry basis, in paragraph (1) of this subsection does not apply to the following units:

(A) lightweight aggregate kilns; and

(B) boilers and process heaters operating at less than 10% of maximum load and with stack O_2 in excess of 15% (i.e., hot-standby mode).

(4) The CO limits in paragraph (1) of this subsection do not apply to the following units:

(A) BIF units that were regulated as existing facilities in 40 CFR Part 266, Subpart H (as was in effect on June 9, 1993) and that are subject to subsection (a)(3) of this section; and

(B) incinerators subject to the CO limits of one of the following:

(i) §111.121 of this title (relating to Single-, Dual-, and Multiple-Chamber Incinerators);

(ii) §113.2072 of this title (relating to Emission Limits) for hospital/medical/infectious waste incinerators; or

(iii) 40 CFR Part 264 or 265, Subpart O, for hazardous waste incinerators.

(d) Compliance flexibility.

(1) Section 117.325 of this title is not an applicable method of compliance with the NO_x emission specifications of this section.

(2) An owner or operator may petition the executive director for an alternative to the CO or ammonia specifications of this section in accordance with §117.325 of this title.

(3) An owner or operator may not use the alternative methods specified in §§117.315, 117.323, and 117.9800 of this title (relating to Alternative Plant-Wide Emission Specifications; Source Cap; and Use of Emission Credits for Compliance) to comply with the NO_x emission specifications of this section. The owner or operator shall use the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title to comply with the NO_x emission specifications of this section, except that electric generating facilities must also comply with the daily and 30-day system cap emission limitations of §117.320 of this title. An owner or operator may use the alternative methods specified in §117.9800 of this title for purposes of complying with §117.320 of this title.

(e) Prohibition of circumvention:

(1) the maximum rated capacity used to determine the applicability of the emission specifications in subsection (a) of this section and the initial control plan, compliance demonstration, monitoring, testing requirements, and final control plan in §§117.335, 117.340, 117.350, and 117.354 of this title (relating to Initial Demonstration of Compliance; Continuous Demonstration of Compliance; Initial Control Plan Procedures; and Final Control Plan Procedures for Attainment Demonstration Emission Specifications) must be:

(A) the greater of the following:

(i) the maximum rated capacity as of December 31, 2000; or

(ii) the maximum rated capacity after December 31, 2000; or

(B) alternatively, the maximum rated capacity authorized by a permit issued under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) on or after January 2, 2001, that the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, provided that the maximum rated capacity authorized by the permit issued on or after January 2, 2001, is no less than the maximum rated capacity represented in the permit application as of January 2, 2001;

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

(3) changes after December 31, 2000, to a unit subject to subsection (a) of this section (ESAD unit) that result in increased NO_x emissions from a unit not subject to subsection (a) of this section (non-ESAD unit), such as redirecting one or more fuel or waste streams

containing chemical-bound nitrogen to an incinerator with a maximum rated capacity of less than 40 MMBtu/hr or a flare, is only allowed if:

(A) the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS that meets the requirements of §117.340(f) or (g) of this title, or through stack testing that meets the requirements of §117.335(e) of this title; and

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

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

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

(f) Operating restrictions. No person shall start or operate any stationary diesel or dual-fuel engine for testing or maintenance between the hours of 6:00 a.m. and noon, except:

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

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

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

§117.340. 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, with an accuracy of ± 5%, to individually and continuously measure the gas and liquid fuel usage. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The owner or operator of units with totalizing fuel flow meters installed prior to March 31, 2005, that do not meet the accuracy requirements of this subsection shall either recertify or replace existing meters to meet the ± 5% accuracy required as soon as practicable but no later than March 31, 2007. For the purpose of compliance with this subsection for units having pilot fuel supplied by a separate fuel system or from an unmonitored portion of the same fuel system, the fuel flow to pilots may be calculated using the manufacturer's design flow rates rather than measured with a fuel flow meter. The calculated pilot fuel flow rate must be added to the monitored fuel flow when fuel flow is totaled.

(1) The units are the following:

(A) for units that are subject to §117.305 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), for stationary gas turbines that are exempt under §117.303(b)(7) of this title (relating to Exemptions):

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

(I) boilers;

(II) process heaters;

(III) boilers and industrial furnaces that were regulated as existing facilities by 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;

(ii) stationary reciprocating internal combustion engines not exempt by §117.303(a)(6), (a)(8), (b)(9), or (b)(10) of this title;

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

(iv) fluid catalytic cracking unit boilers using supplemental fuel; and

(B) for units subject to §117.310 of this title (relating to Emission Specifications for Attainment Demonstration):

(i) boilers (excluding wood-fired boilers that must comply by maintaining records of fuel usage as required in §117.345(f) of this title (relating to Notification, Recordkeeping, and Reporting Requirements) or monitoring in accordance with paragraph (2)(A) of this subsection);

(ii) process heaters;

(iii) boilers and industrial furnaces that were regulated as existing facilities by 40 CFR Part 266, Subpart H, as was in effect on June 9, 1993;

(iv) duct burners used in turbine exhaust ducts;

(v) stationary, reciprocating internal combustion engines;

(vi) stationary gas turbines;

(vii) fluid catalytic cracking unit boilers and furnaces using supplemental fuel;

(viii) lime kilns;

(ix) lightweight aggregate kilns;

(x) heat treating furnaces;

(xi) reheat furnaces;

(xii) magnesium chloride fluidized bed dryers; and

(xiii) incinerators (excluding vapor streams resulting from vessel cleaning routed to an incinerator, provided that fuel usage is quantified using good engineering practices, including calculation methods in general use and accepted in new source review permitting in Texas. All other fuel and vapor streams must be monitored in accordance with this subsection.)

(2) The following are alternatives to the fuel flow monitoring requirements of paragraph (1) of this subsection.

(A) Units operating with a nitrogen oxides (NO_x) and diluent continuous emissions monitoring system (CEMS) under subsection (f) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 CFR Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

(B) Units that vent to a common stack with a NO_x and diluent CEMS under subsection (f) of this section may use a single totalizing fuel flow meter.

(C) Diesel engines operating with run time meters may meet the fuel flow monitoring requirements of this subsection through monthly fuel use records maintained for each engine.

(D) Stationary reciprocating internal combustion engines and stationary gas turbines equipped with a continuous monitoring system that continuously monitors horsepower and hours of operation are not required to install totalizing fuel flow meters. The continuous monitoring system must be installed, calibrated, maintained, and operated according to manufacturers' recommended procedures.

(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 $2.2(10^{11})$ British thermal units 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 greater than or equal to 100 MMBtu/hr, except as provided in subsection (g) of this section.

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

(A) units listed in §117.303(b)(3) - (5) and (8) - (10) of this title;

(B) process heaters operating with a carbon dioxide CEMS for diluent monitoring under subsection (g) 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 (f) of this section if O_2 is the monitored diluent under that subsection. However, if new O_2 monitors are required as a result of this subsection, the criteria in subsection (f) 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 that use a chemical reagent for reduction of NO_x;

(E) units that the owner or operator elects to comply with the NO_x emission specifications of §117.305 of this title using a pound per MMBtu (lb/MMBtu) limit on a 30-day rolling average;

(F) lime kilns and lightweight aggregate kilns;

(G) units with a rated heat input greater than or equal to 100 MMBtu/hr that are subject to §117.310(a) of this title; and

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

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

(A) for purposes of §117.305 of this title, units listed §117.303(b)(3) - (5) and (8) - (10) of this title; [and]

(B) units subject to the NO_X CEMS requirements of 40 CFR Part 75; and [.]

(C) stationary diesel engines equipped with selective catalytic reduction (SCR) systems that meet the following criteria.

(i) The SCR system must use a reductant other than the engine's fuel.

(ii) The SCR system must operate with a diagnostic system that monitors reductant quality and tank levels.

(iii) The diagnostic system must alert owners or operators to the need to refill the reductant tank before it is empty or to replace the reductant if the reductant does not meet applicable concentration specifications.

(iv) If the SCR system uses input from an exhaust NO_X sensor (or other sensor) to alert owners or operators when the reductant quality is inadequate, the reductant quality does not need to be monitored separately by the diagnostic system.

(v) The reductant tank level must be monitored in accordance with the manufacturer's design to demonstrate compliance with this subparagraph.

(vi) The method of alerting an owner or operator must be a visual or audible alarm.

(3) The owner or operator shall use one of the following methods to provide substitute emissions compliance data during periods when the NO_x monitor is off-line:

(A) if the NO_x monitor is a CEMS:

(i) subject to 40 CFR Part 75, use the missing data procedures specified in 40 CFR Part 75, Subpart D (Missing Data Substitution Procedures); or

(ii) subject to 40 CFR Part 75, Appendix E, use the missing data procedures specified in 40 CFR Part 75, Appendix E, §2.5 (Missing Data Procedures);

(B) use 40 CFR Part 75, Appendix E monitoring in accordance with §117.1240(e) of this title (relating to Continuous Demonstration of Compliance);

(C) if the NO_x monitor is a PEMS:

(i) use the methods specified in 40 CFR Part 75, Subpart D; or

(ii) use calculations in accordance with §117.8110(b) of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources); or

(D) use the maximum block one-hour emission rate as measured during the initial demonstration of compliance required in §117.335(f) of this title (relating to Initial Demonstration of Compliance); or

(E) use the following procedures:

(i) for NO_X monitor downtime periods less than 24 consecutive hours, use the maximum block one-hour NO_X emission rate, in lb/MMBtu, from the previous 24 operational hours of the unit;

(ii) for NO_X monitor downtime periods equal to or greater than 24 consecutive hours, use the maximum block one-hour NO_X emission rate, in lb/MMBtu, from the previous 720 operational hours of the unit; and

(iii) if the fuel flow or stack exhaust flow monitor required by subsection (a) of this section is off-line simultaneous with the NO_X monitor downtime, the owner or operator shall use the maximum block one-hour NO_X pound per hour emission rate for the substitute data under clause (i) or (ii) of this subparagraph in lieu of the lb/MMBtu emission rate.

(d) Ammonia monitoring requirements. The owner or operator of units that are subject to the ammonia emission specifications of §117.310(c)(2) of this title shall comply with the ammonia monitoring requirements of §117.8130 of this title (relating to Ammonia Monitoring). <u>Units identified in subsection (c)(2)(C) of this section are exempt from the ammonia monitoring requirements of this subsection.</u>

(e) 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 methods specified in §117.8120 of this title (relating to Carbon Monoxide (CO) Monitoring).

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

(1) The CEMS must meet the requirements of §117.8100(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources).

(2) For units subject to §117.310 of this title:

(A) all bypass stacks must be monitored, in order to quantify emissions directed through the bypass stack:

(i) if the CEMS is located upstream of the bypass stack, then:

(I) no effluent streams from other potential sources of NO_X emissions may be introduced between the CEMS and the bypass stack; and

(II) the owner or operator shall install, operate, and maintain a continuous monitoring system to automatically record the date, time, and duration of each event when the bypass stack is open; and

(ii) process knowledge and engineering calculations may be used to determine volumetric flow rate for purposes of calculating mass emissions for each event when the bypass stack is open, provided that:

(I) the maximum potential calculated flow rate is used for emission calculations; and

(II) the owner or operator maintains, and makes available upon request by the executive director, records of all process information and calculations used for this determination; and

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

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

(1) The PEMS must predict the pollutant emissions in the units of the applicable emission specifications of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources).

(2) The PEMS must meet the requirements of §117.8100(b) of this title.

(h) Engine monitoring. The owner or operator of any stationary gas engine subject to §117.305 of this title that is not equipped with NO_x CEMS or PEMS shall stack test engine NO_x and CO emissions as specified in §117.8140(a) of this title (relating to Emission Monitoring for Engines). The owner or operator of any stationary internal combustion engine subject to §117.310 of this title that is not equipped with NO_x CEMS or PEMS shall stack test engine NO_x and CO emissions as specified in §117.8140(a) and (b) of this title.

(i) Monitoring for stationary gas turbines less than 30 MW. The owner or operator of any stationary gas turbine rated less than 30 MW using steam or water injection to comply with the emission specifications of §117.305 or §117.315 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT) and 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 (e) 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 must be accurate to within ± 5.0%;

(B) the steam-to-fuel or water-to-fuel ratio monitoring data must constitute the method for demonstrating continuous compliance with the applicable emission specification of §117.305 or §117.315 of this title; and

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

(j) Run time meters. The owner or operator of any stationary gas turbine or stationary internal combustion engine claimed exempt using the exemption of §117.303(a)(6)(D), (a)(10), (a)(11), (b)(2) or (b)(9) of this title shall record the operating time with an elapsed run time meter. Any run time meter installed on or after October 1, 2001, must be non-resettable.

(k) Hydrogen (H_2) monitoring. The owner or operator claiming the H_2 multiplier of §117.305(b)(6) or §117.315(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 must 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 must be tested according to American Society for Testing and Materials (ASTM) Method D1945-81 or ASTM Method D2650-83, or other methods that are demonstrated to the satisfaction of the executive director and the United States Environmental Protection Agency 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 must 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 that is the source of the H_2 must 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.

(l) Data used for compliance.

(1) After the initial demonstration of compliance required by §117.335 of this title, the methods required in this section must be used to determine compliance with the emission specifications of §117.305 of this title. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission limitations.

(2) For units subject to §117.310(a) of this title, the methods required in this section must be used in conjunction with the requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) to determine compliance. For enforcement purposes, the executive director may also use other commission

compliance methods to determine whether the source is in compliance with applicable emission limitations.

(m) Enforcement of NO_x RACT limits. If compliance with §117.305 of this title is selected, no unit subject to §117.305 of this title may be operated at an emission rate higher than that allowed by the emission specifications of §117.305 of this title. If compliance with §117.315 of this title is selected, no unit subject to §117.315 of this title may be operated at an emission rate higher than that approved by the executive director under §117.352(b) of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology).

(n) Loss of NO_x RACT exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.303(b)(2) of this title shall notify the executive director within seven days if the Btu/yr or hour-per-year limit specified in §117.10 of this title (relating to Definitions), as appropriate, is exceeded.

(1) If the limit is exceeded, the exemption from the emission specifications of this division is 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 must include a schedule of increments of progress for the installation of the required control equipment.

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

(o) Testing and operating requirements. The owner or operator of units that are subject to §117.310(a) of this title shall comply with the following.

(1) The owner or operator of units that are subject to §117.310(a) of this title shall test the units as specified in §117.335 of this title in accordance with the schedule specified in §117.9020(2) of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources).

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

(p) Emission allowances. The owner or operator of units that are subject to §117.310(a) of this title shall comply with the following.

(1) The NO_X testing and monitoring data of subsections (a), (c), (f), (g), and (o) of this section, together with the level of activity, as defined in §101.350 of this title (relating to Definitions), must be used to establish the emission factor for calculating actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program.

(2) For units not operating with CEMS or PEMS, the following apply.

(A) Retesting as specified in subsection (o)(1) of this section is required within 60 days after any modification that could reasonably be expected to increase the NO_X emission rate.

(B) Retesting as specified in subsection (o)(1) of this section may be conducted at the discretion of the owner or operator after any modification that could reasonably be expected to decrease the NO_X emission rate, including, but not limited to, installation of post-combustion controls, low-NO_X burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation, and fuel-lean and conventional (fuel-rich) reburn.

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

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

(3) The emission factor in paragraph (1) or (2) of this subsection is multiplied by the unit's level of activity to determine the unit's actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

SUBCHAPTER B: COMBUSTION CONTROL AT MAJOR INDUSTRIAL COMMERCIAL, AND INSTITUTIONAL SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 4: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MAJOR SOURCES

§§117.410, 117.440

Statutory Authority

The amended rules are proposed under Texas Water Code (TWC), §5.102, concerning general powers; §5.103, concerning Rules; TWC, §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; TWC, §7.002, concerning Enforcement Authority, which authorizes the commission to enforce the provisions of the Water Code and the Health and Safety Code within the commission’s jurisdiction; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The amendments are also proposed under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning the State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants; and THSC, §382.021, concerning Sampling

Methods and Procedures.

The proposed amendments implement TWC, §§5.102, 5.103 and 7.002; and THSC, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.021.

§117.410. Emission Specifications for Eight-Hour Attainment Demonstration.

(a) Emission specifications for eight-hour ozone attainment demonstration. For units located in Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, or Tarrant County, no person shall allow the discharge into the atmosphere nitrogen oxides (NO_X) emissions in excess of the following emission specifications, in accordance with the applicable schedule in §117.9030(b) of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources), except as provided in subsection (d) of this section:

(1) gas-fired boilers:

(A) with a maximum rated capacity equal to or greater than 100 million British thermal units per hour (MMBtu/hr), 0.020 pounds per million British thermal units (lb/MMBtu);

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

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

(2) liquid-fired boilers, 2.0 pounds per 1,000 gallons of liquid burned;

(3) process heaters:

(A) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, 0.025 lb/MMBtu; and

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

(4) stationary, reciprocating internal combustion engines:

(A) gas-fired rich-burn engines:

(i) fired on landfill gas, 0.60 grams per horsepower-hour (g/hp-hr); and

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

(B) gas-fired lean-burn engines:

(i) placed into service before June 1, 2007, that have not been modified, reconstructed, or relocated on or after June 1, 2007, 0.70 g/hp-hr; and

(ii) placed into service, modified, reconstructed, or relocated on or after June 1, 2007:

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

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

(C) dual-fuel engines, 0.50 g/hp-hr;

(D) diesel engines, excluding dual-fuel engines, placed into service before March 1, 2009, that have not been modified, reconstructed, or relocated on or after March 1, 2009, the lower of 11.0 g/hp-hr or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data;

(E) for diesel engines, excluding dual-fuel engines, not subject to subparagraph (D) of this paragraph:

(i) with a horsepower (hp) rating of less than 50 hp that are installed, modified, reconstructed, or relocated on or after March 1, 2009, 5.0 g/hp-hr;

(ii) with a hp rating of 50 hp or greater, but less than 100 hp, that are installed, modified, reconstructed, or relocated on or after March 1, 2009, 3.3 g/hp-hr;

(iii) with a hp rating of 100 hp or greater, but less than 750 hp, that are installed, modified, reconstructed, or relocated on or after March 1, 2009, 2.8 g/hp-hr; and

(iv) with a hp rating of 750 hp or greater that are installed, modified, reconstructed, or relocated on or after March 1, 2009, 4.5 g/hp-hr; and

(F) for the purposes of this paragraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations (CFR) §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account;

(5) stationary gas turbines:

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

(B) rated at 1.0 MW or greater, but less than 10 MW, 0.15 lb/MMBtu; and

(C) rated at less than 1.0 MW, 0.26 lb/MMBtu;

(6) duct burners used in turbine exhaust ducts, the corresponding gas turbine emission specification of paragraph (5) of this subsection;

(7) kilns:

(A) lime kilns, 3.7 pounds per ton (lb/ton) of calcium oxide, demonstrated either:

(i) on an individual kiln basis; or

(ii) on a site-wide production rate weighted average basis, using the following equation:

Figure: 30 TAC §117.410(a)(7)(A)(ii) (No changes)

(B) brick and ceramic kilns, one of the following:

(i) a 40% reduction from the daily NO_x emissions reported to the Emissions Assessment Section for the calendar year 2000 Emissions Inventory. To ensure that this emission specification will result in a real 40% reduction in actual emissions, a consistent methodology must be used to calculate the 40% reduction;

(ii) 0.175 lb/ton of product for brick kilns; or

(iii) 0.27 lb/ton of product for ceramic kilns;

(8) metallurgical furnaces:

(A) heat treating furnaces, 0.087 lb/MMBtu. For heat treating furnaces equipped with NO_x continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) that comply with §117.440 of this title (relating to Continuous Demonstration of Compliance), this emission specification only applies from March 1 to October 31 of any calendar year;

(B) reheat furnaces, 0.10 lb/MMBtu. For reheat furnaces equipped with NO_x CEMS or PEMS that comply with §117.440 of this title, this emission specification only applies from March 1 to October 31 of any calendar year; and

(C) lead smelting blast (cupola) and reverberatory furnaces used in conjunction, the combined rate of 0.45 lb/ton product;

(9) incinerators, either of the following:

(A) an 80% reduction from the daily NO_x emissions reported to the Emissions Assessment Section for the calendar year 2000 Emissions Inventory. To ensure that this emission specification will result in a real 80% reduction in actual emissions, a consistent methodology must be used to calculate the 80% reduction; or

(B) 0.030 lb/MMBtu;

(10) glass and fiberglass melting furnaces:

(A) container glass melting furnaces:

(i) 4.0 lb/ton of glass pulled during furnace operation equal to or greater than 25% of the permitted glass production capacity; and

(ii) the applicable maximum allowable pound per hour NO_x permit limit in a permit issued before June 1, 2007, during furnace operation less than 25% of the permitted glass production capacity;

(B) mineral wool-type cold-top electric fiberglass melting furnaces, 4.0 lb/ton of product pulled;

(C) mineral wool-type fiberglass regenerative furnaces, 1.45 lb/ton of product pulled; and

(D) mineral wool-type fiberglass non-regenerative gas-fired furnaces, 3.1 lb/ton product pulled;

(11) gas-fired curing ovens used for the production of mineral wool-type or textile-type fiberglass, 0.036 lb/MMBtu;

(12) natural gas-fired ovens and heaters, 0.036 lb/MMBtu;

(13) natural gas-fired dryers:

(A) dryers used in organic solvent, printing ink, clay, brick, ceramic tile, calcining, and vitrifying processes, 0.036 lb/MMBtu;

(B) spray dryers used in ceramic tile manufacturing processes, 0.15 lb/MMBtu; and

(14) as an alternative to the emission specifications in paragraphs (1) - (13) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu. The capacity factor as of December 31, 2000, must be used to determine whether the unit is eligible for the emission specification of this paragraph. A 12-month rolling average must be used to determine the annual capacity factor for units placed into service after December 31, 2000.

(b) NO_x averaging time. The emission specifications of subsection (a) of this section apply:

(1) if the unit is operated with a NO_x CEMS or PEMS under §117.440 of this title, either as:

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

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

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

(2) if the unit is not operated with a NO_X CEMS or PEMS under §117.440 of this title, a block one-hour average, in the units of the applicable standard. Alternatively for boilers and process heaters, the emission specification may be applied in pounds per hour, as specified in paragraph (1)(C) of this subsection.

(c) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to NO_X emission specifications in subsection (a) of this section, emissions in excess of the following, except as provided in §117.425 of this title (relating to Alternative Case Specific Specifications) or paragraph (3) or (4) of this subsection.

(1) Carbon monoxide (CO) emissions must not exceed 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines; or 775 ppmv at 7.0% O_2, dry basis for wood fuel-fired boilers or process heaters):

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

(B) on a block one-hour averaging period, for units not equipped with CEMS or PEMS for CO.

(2) For units that inject urea or ammonia into the exhaust stream for NO_X control, ammonia emissions must not exceed 10 ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), [and] gas-fired lean-burn engines, and diesel engines; 7.0% O_2, dry, for incinerators; and 3.0% O_2, dry, for all other units, based on:

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

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

(3) The correction of CO emissions to 3.0% O_2, dry basis, in paragraph (1) of this subsection does not apply to boilers and process heaters operating at less than 10% of maximum load and with stack O_2 in excess of 15% (i.e., hot-standby mode).

(4) The CO specifications in paragraph (1) of this subsection do not apply to incinerators subject to the CO limits of one of the following:

(A) §111.121 of this title (relating to Single-, Dual-, and Multiple-Chamber Incinerators);

(B) §113.2072 of this title (relating to Emission Limits) for hospital/medical/infectious waste incinerators; or

(C) 40 CFR Part 264 or 265, Subpart O, for hazardous waste incinerators.

(d) Compliance flexibility.

(1) An owner or operator may use any of the following alternative methods to comply with the NO_x emission specifications of this section:

(A) §117.423 of this title (relating to Source Cap); or

(B) §117.9800 of this title (relating to Use of Emission Credits for Compliance).

(2) Section 117.425 of this title is not an applicable method of compliance with the NO_x emission specifications of this section.

(3) An owner or operator may petition the executive director for an alternative to the CO or ammonia specifications of this section in accordance with §117.425 of this title.

(e) Prohibition of circumvention.

(1) The maximum rated capacity used to determine the applicability of the emission specifications in this section and the initial compliance demonstration, monitoring, testing requirements, and final control plan in §§117.435, 117.440, and 117.454 of this title (relating to Initial Demonstration of Compliance; Continuous Demonstration of Compliance;

and Final Control Plan Procedures for Attainment Demonstration Emission Specifications) must be the greater of the following:

(A) the maximum rated capacity as of December 31, 2000;

(B) the maximum rated capacity after December 31, 2000; or

(C) the maximum rated capacity authorized by a permit issued under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) after December 31, 2000.

(2) A unit's classification is determined by the most specific classification applicable to the unit as of December 31, 2000. For example, a unit that is classified as a stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, is classified as a stationary gas-fired engine for the purposes of this chapter.

(3) Changes after December 31, 2000, to a unit subject to an emission specification in this section that result in increased NO_x emissions from a unit not subject to an emission specification of this section, such as redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator with a maximum rated capacity of less than 40 MMBtu/hr, or a flare, are only allowed if:

(A) the increase in NO_X emissions at the unit not subject to this section is determined using a CEMS or PEMS that meets the requirements of §117.440 of this title, or through stack testing that meets the requirements of §117.435 of this title; and

(B) emission credits equal to the increase in NO_X emissions at the unit not subject to this section are obtained and used in accordance with §117.9800 of this title.

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

(5) The availability under subsection (a)(14) of this section of an emission specification for units with an annual capacity factor of 0.0383 or less is based on the unit's status as of December 31, 2000. Reduced operation after December 31, 2000, cannot be used to qualify for a more lenient emission specification under subsection (a)(14) of this section than would otherwise apply to the unit.

(f) Operating restrictions. No person may start or operate any stationary diesel or dual-fuel engine for testing or maintenance of the engine between the hours of 6:00 a.m. and noon, except:

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

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

(3) firewater pumps for emergency response training conducted from April 1 through October 31.

§117.440. 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, with an accuracy of ± 5%, to individually and continuously measure the gas and liquid fuel usage. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The owner or operator must continuously operate the totalizing fuel flow meter at least 95% of the time when the unit is operating during a calendar year. For the purpose of compliance with this subsection for units having pilot fuel supplied by a separate fuel system or from an unmonitored portion of the same fuel system, the fuel flow to pilots may be calculated using the manufacturer's design flow rates rather than measured with a fuel flow meter. The calculated pilot fuel flow rate must be added to the monitored fuel flow when fuel flow is totaled.

(1) The units are the following units subject to §117.405 (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or §117.410 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstrations):

(A) boilers (excluding wood-fired boilers that must comply by maintaining records of fuel usage as required in §117.445(f) of this title (relating to Notification, Recordkeeping, and Reporting Requirements) or monitoring in accordance with paragraph (2)(A) of this subsection);

(B) process heaters;

(C) duct burners used in turbine exhaust ducts;

(D) stationary, reciprocating internal combustion engines;

(E) stationary gas turbines;

(F) lime kilns

(G) brick and ceramic kilns;

(H) heat treating furnaces;

(I) reheat furnaces;

(J) lead smelting blast (cupola) and reverberatory furnaces;

(K) glass and fiberglass/mineral wool melting furnaces;

(L) incinerators (excluding vapor streams resulting from vessel cleaning routed to an incinerator, provided that fuel usage is quantified using good engineering practices, including calculation methods in general use and accepted in new source review permitting in Texas. All other fuel and vapor streams must be monitored in accordance with this subsection);

(M) gas-fired glass, fiberglass, and mineral wool curing ovens;

(N) natural gas-fired ovens and heaters; and

(O) natural gas-fired dryers used in organic solvent, printing ink, clay, brick, ceramic, and calcining and vitrifying processes.

(2) The following are alternatives to the fuel flow monitoring requirements of paragraph (1) of this subsection.

(A) Units operating with a nitrogen oxides (NO_x) and diluent continuous emissions monitoring system (CEMS) under subsection (f) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (CFR) Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

(B) Units that vent to a common stack with a NO_x and diluent CEMS under subsection (f) of this section may use a single totalizing fuel flow meter.

(C) Diesel engines operating with run time meters may meet the fuel flow monitoring requirements of this subsection through monthly fuel use records maintained for each engine.

(D) Stationary reciprocating internal combustion engines and gas turbines equipped with a continuous monitoring system that continuously monitors horsepower and hours of operation are not required to install totalizing fuel flow meters. The continuous monitoring system must be installed, calibrated, maintained, and operated according to manufacturers' recommended procedures.

(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 $2.2(10^{11})$ British thermal units per year (Btu/yr):

(A) boilers with a rated heat input greater than or equal to 100 million British thermal units per hour (MMBtu/hr); and

(B) process heaters with a rated heat input greater than or equal to 100 MMBtu/hr, except:

(i) as provided in subsection (g) of this section; and

(ii) for process heaters operating with a carbon dioxide (CO_2) CEMS for diluent monitoring under subsection (f) of this section.

(2) 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 (f) of this section if O_2 is the monitored diluent under that subsection. However, if new O_2 monitors are required as a result of this subsection, the criteria in subsection (f) 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) units with a rated heat input greater than or equal to 100 MMBtu/hr that are subject to §117.405(a) or (b) or §117.410(a) of this title;

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

(C) units that use a chemical reagent for reduction of NOX ;

(D) units that the owner or operator elects to comply with the NO_x emission specifications of §117.405(a) or (b) of this title or §117.410(a) of this title using a pound per MMBtu (lb/MMBtu) limit on a 30-day rolling average;

(E) lime kilns; and

(F) brick kilns and ceramic kilns.

(2) The following units [Units subject to the NO_x CEMS requirements of 40 CFR Part 75] are not required to install CEMS or PEMS under this subsection; [.]

(A) units subject to the NO_x CEMS requirements of 40 CFR Part 75; and

(B) stationary diesel engines equipped with selective catalytic reduction (SCR) systems that meet the following criteria.

(i) The SCR system must use a reductant other than the engine's fuel.

(ii) The SCR system must operate with a diagnostic system that monitors reductant quality and tank levels.

(iii) The diagnostic system must alert owners or operators to the need to refill the reductant tank before it is empty or to replace the reductant if the reductant does not meet applicable concentration specifications.

(iv) If the SCR system uses input from an exhaust NO_x sensor (or other sensor) to alert owners or operators when the reductant quality is inadequate, the reductant quality does not need to be monitored separately by the diagnostic system.

(v) The reductant tank level must be monitored in accordance with the manufacturer's design to demonstrate compliance with this subparagraph.

(vi) The method of alerting an owner or operator must be a visual or audible alarm.

(3) The owner or operator shall use one of the following methods to provide substitute emissions compliance data during periods when the NO_x monitor is off-line:

(A) if the NO_x monitor is a CEMS:

(i) subject to 40 CFR Part 75, use the missing data procedures specified in 40 CFR Part 75, Subpart D (Missing Data Substitution Procedures); or

(ii) subject to 40 CFR Part 75, Appendix E, use the missing data procedures specified in 40 CFR Part 75, Appendix E, §2.5 (Missing Data Procedures);

(B) use 40 CFR Part 75, Appendix E monitoring in accordance with §117.1340(d) of this title (relating to Continuous Demonstration of Compliance);

(C) if the NO_X monitor is a PEMS:

(i) use the methods specified in 40 CFR Part 75, Subpart D; or

(ii) use calculations in accordance with §117.8110(b) of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources); or

(D) the maximum block one-hour emission rate as measured during the initial demonstration of compliance required in §117.435(e) of this title (relating to Initial Demonstration of Compliance).

(d) Ammonia monitoring requirements. The owner or operator of any unit subject to §117.405(a) or (b) or §117.410(a) of this title and the ammonia emission specification of §117.405(d)(2) or §117.410(c)(2) of this title shall monitor ammonia emissions from the unit according to the requirements of §117.8130 of this title (relating to Ammonia Monitoring). <u>Units identified in subsection (c)(2)(B) of this section are exempt from the ammonia monitoring requirements of this subsection.</u>

(e) 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 methods specified in §117.8120 of this title (relating to Carbon Monoxide (CO) Monitoring).

(f) CEMS requirements. The owner or operator of any CEMS used to meet a pollutant monitoring requirement of this section shall comply with the requirements of §117.8100(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources).

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

(1) The PEMS must predict the pollutant emissions in the units of the applicable emission limitations of this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources).

(2) The PEMS must meet the requirements of §117.8100(b) of this title.

(h) 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 specified in §117.8140(a) of this title (relating to Emission Monitoring for Engines).

(i) Run time meters. The owner or operator of any stationary gas turbine or stationary internal combustion engine claimed exempt using the exemption of §117.403(a)(7)(D), (8), or (9) or (b)(2)(D) of this title (relating to Exemptions) shall record the operating time with a non-resettable elapsed run time meter.

(j) Data used for compliance. After the initial demonstration of compliance required by §117.435 of this title, the methods required in this section must be used to determine compliance with the emission specifications of §117.405(a) or (b) or §117.410(a) of this title. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the unit is in compliance with applicable emission specifications.

(k) Testing requirements.

(1) The owner or operator of units that are subject to the emission specifications of §117.405(a) or (b) or §117.410(a) of this title shall test the units as specified in §117.435 of this title in accordance with the applicable schedule specified in §117.9030 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources).

(2) The owner or operator of any unit not equipped with CEMS or PEMS that are subject to the emission specifications of §117.405(a) or (b) of this title or §117.410(a) of this title shall retest the unit as specified in §117.435 of this title within 60 days after any modification that could reasonably be expected to increase the NO_x emission rate.

SUCHAPTER C: COMBUSTION CONTROL AT MAJOR UTILITY ELECTRIC GENERATION SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 2: BEXAR COUNTY OZONE NONATTAINMENT AREA UTILITY ELECTRIC GENERATION SOURCES

§§117.1100, 117.1103, 117.1105, 117.1120, 117.1140, 117.1145, 117.1152

Statutory Authority

The new rules are proposed under Texas Water Code (TWC), §5.102, concerning general powers; §5.103, concerning Rules; TWC, §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; TWC, §7.002, concerning Enforcement Authority, which authorizes the commission to enforce the provisions of the Water Code and the Health and Safety Code within the commission's jurisdiction; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new rules are also proposed under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning the State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants; and THSC, §382.021, concerning Sampling

Methods and Procedures.

The proposed new rules implement TWC, §§5.102, 5.103 and 7.002; and THSC, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.021.

§117.1100. Applicability.

(a) This division applies to the following units used in an electric power generating system, as defined in §117.10 of this title (relating to Definitions), located in the Bexar County ozone nonattainment area:

(1) utility boilers;

(2) auxiliary steam boilers;

(3) stationary gas turbines; and

(4) duct burners used in turbine exhaust ducts.

(b) This division is applicable for the life of each affected unit in an electric power generating system or until this division or sections of this title that are applicable to an affected unit are rescinded.

§117.1103. Exemptions.

The following units are exempt from this division, except as specified in §117.1140 and 117.1145 of this title (relating to Demonstration of Compliance; and Notification, Recordkeeping, and Reporting Requirements):

(1) utility boilers or auxiliary steam boilers with an annual heat input less than or equal to 220,000 million British thermal units per year, on a rolling 12-month basis;

(2) stationary gas turbines that operate less than 850 hours per year, on a rolling 12-month basis; or

(3) stationary gas turbines that are used solely to power other gas turbines or engines during startups.

§117.1105. Emission Specifications for Reasonably Available Control Technology (RACT).

(a) Emission Specifications. No person shall allow the discharge into the atmosphere nitrogen oxides (NO_X) emissions in excess of the following emission specifications, in accordance with the applicable schedule in §117.9110 of this title (relating to Compliance Schedule for Bexar County Ozone Nonattainment Area Utility Electric Generation Sources):

(1) stationary gas turbines, including duct burners used in turbine exhaust ducts, 0.032 pound per million British thermal units (lb/MMBtu) heat input on a rolling 30-day average basis;

(2) utility boilers or auxiliary steam boilers, while firing natural gas or a combination of natural gas and oil, 0.20 lb/MMBtu heat input on a rolling 30-day average basis;

(3) utility boilers or auxiliary steam boilers controlled with selective catalytic reduction, while firing coal, 0.069 lb/MMBtu heat input on a rolling 30-day average basis;

(4) utility boilers or auxiliary steam boilers not controlled with selective catalytic reduction, while firing coal, 0.20 lb/MMBtu heat input on a rolling 30-day average basis; and

(5) utility boilers or auxiliary steam boilers, while firing oil only, 0.30 lb/MMBtu heat input on an hourly basis.

(b) Compliance flexibility. An owner or operator may use any of the following alternative methods to comply with the NO_X emission specifications of this section:

(1) §117.1120 of this title (relating to System Cap); or

(2) §117.9800 of this title (relating to Use of Emission Credits for Compliance).

§117.1120. System Cap.

(a) An owner or operator of an electric generating facility (EGF), as defined in §117.10 of this title (relating to Definitions), may achieve compliance with the nitrogen oxides (NO_X) emission specifications in §117.1105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) by achieving equivalent NO_X emission reductions obtained by compliance with a system cap emission limitation in accordance with the requirements of this section.

(b) Each EGF within an electric power generating system, as defined in §117.10 of this title, that started operation before January 1, 2025, and is subject to §117.1105 of this title, must be included in the system cap.

(c) The system cap must be calculated using the following equation.

Figure: 30 TAC §117.1120(c)

$$System\ Cap = \sum_{i=1}^{N} (H_i \times R_i)$$

Where:

System Cap = NO_X emission cap for an electric power generating system in pounds per day on a rolling 30-day average basis;

i = each EGF in the electric power generating system;

N = the total number of EGFs in the system cap;

Hi = the average of the daily heat input for each EGF in the system cap, in million British thermal units per day, as certified to the executive director, for any 30-day period in

2019, 2020, 2021, 2022, or 2023; the same 30-day period must be used for all EGFs in the emission cap; and

Ri = the applicable emission specification in §117.1105 of this title for each EGF.

(d) Continuous compliance with the system cap must be demonstrated in accordance with the requirements in §117.1140 of this title (relating to Demonstration of Compliance).

(e) The owner or operator shall maintain daily records indicating the NO_X emissions and fuel usage from each EGF and summations of total NO_X emissions and fuel usage for all EGFs under the system cap on a daily basis. Records must also be retained in accordance with §117.1145 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(f) The owner or operator shall report any exceedance of the system cap emission limit within 48 hours to the appropriate regional office. The owner or operator shall then follow up within 21 days of the exceedance with a written report to the regional office that includes an analysis of the cause for the exceedance with appropriate data to demonstrate the amount of emissions in excess of the system cap 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 §117.1145 of this title.

(g) The owner or operator shall demonstrate compliance with the system cap in accordance with the schedule specified in §117.9110 of this title (relating to Compliance Schedule for Bexar County Ozone Nonattainment Area Utility Electric Generation Sources).

(h) An EGF that is permanently retired or decommissioned and rendered inoperable may be included in the system cap emission limit provided that the permanent shutdown occurred on or after January 1, 2025.

(i) Emission reductions from shutdowns or curtailments that have been used for netting or offset purposes under the requirements of Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) may not be included in the in the calculation of the system cap in subsection (c) of the section.

(j) For the purposes of determining compliance with the system cap, the contribution of each affected EGF that is operating during a startup, shutdown, or emissions event as defined in §101.1 of this title (relating to Definitions) must be calculated from the NO_X emission rate measured by the NO_X monitor, if the monitor is operating properly. If the NO_X monitor is not operating properly, the substitute data procedures identified in §117.1140 of this title must be used.

(k) Emission credits may be used in accordance with the requirements of §117.9800 of this title (relating to Use of Emission Credits for Compliance) to exceed the system cap.

§117.1140. Demonstration of Compliance.

(a) Nitrogen oxides (NO_X) monitoring. The owner or operator of each unit subject to the emission specifications in §117.1105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system

(PEMS) to measure NO_X on an individual basis.

(1) Each CEMS or PEMS is subject to the relative accuracy test audit relative accuracy requirements of 40 Code of Federal Regulations (CFR) Part 75, Appendix B, Figure 2, except the concentration options (parts per million by volume (ppmv) and pound per million British thermal units (lb/MMBtu)) do not apply. Each CEMS or PEMS must meet either the relative accuracy percent requirement of 40 CFR Part 75, Appendix B, Figure 2, or an alternative relative accuracy requirement of ± 2.0 ppmv from the reference method mean value.

(2) Each CEMS or PEMS is subject to the requirements of §117.8110 of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources).

(3) Each PEMS must predict NO_X emissions in the units of the applicable emission limitations of this division and PEMS and fuel flow meters must be used to demonstrate continuous compliance with the emission specifications of this division.

(b) Acid rain peaking units. In lieu of the NO_X monitoring requirements in subsection (a) of this section, the owner or operator of each peaking unit as defined in 40 CFR §72.2, may monitor operating parameters for each unit in accordance with 40 CFR Part 75, Appendix E, and calculate NO_X emission rates based on those procedures.

(c) Totalizing fuel flow meters. The owner or operator of each unit subject to the emission specifications in §117.1105 of this title and each unit using the exemption in §117.1103(1) of this title (relating to Exemptions) shall install, calibrate, maintain, and operate totalizing fuel flow meters to individually and continuously measure the gas and liquid fuel usage. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. In lieu of installing a totalizing fuel flow meter on a unit, an owner or operator may opt to assume fuel consumption at maximum design fuel flow rates during hours of the unit's operation.

(d) Run time meters. The owner or operator of a unit using the exemption of §117.1103(2) of this title shall record the operating time hours with an elapsed run time meter.

(e) Loss of exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the exemptions in §117.1103(1) or (2) of this title, shall notify the executive director within seven days if the applicable limit is exceeded.

(1) If the limit is exceeded, the exemption from the emission specifications of this division is 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 must include a schedule of increments of progress for the installation of the required control equipment.

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

(f) Data used for compliance. The methods required in this section must be used to demonstrate compliance with the emission specifications of §117.1105 of this title and the system cap in §117.1120 of this title (relating to System Cap). For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the unit is in compliance with applicable emission specifications.

(1) For units complying with the NO_X emission specifications of §117.1105 of this title in pounds per million British thermal units (lb/MMBtu) on a rolling 30-day average basis, the rolling 30-day average is calculated for each day that fuel was combusted in the unit, and is the total NO_X emissions (in pounds) from the unit for the preceding 30 days that fuel was combusted in the unit, divided by the total heat input (in MMBtu) for the unit during the same 30-day period.

(2) For any electric generating facility (EGF) complying with the system cap in §117.1120 of this title (relating to System Cap) in pounds per day on a rolling 30-day average basis, the rolling 30-day average is calculated for each day that fuel was combusted in the unit, and is the average of the total pounds of NO_X emissions per day from all EGFs included in the system cap for the preceding 30 days that fuel was combusted in the units.

(g) Data Substitution. The missing data procedures specified in 40 CFR Part 75, Subpart D (Missing Data Substitution Procedures) must be used to provide substitute emissions compliance data during periods when the NO_X monitor is off-line except as follows.

(1) A peaking unit, as defined in 40 CFR §72.2, subject to 40 CFR Part 75, Appendix E, may use the missing data procedures specified in 40 CFR Part 75, Appendix E, §2.5 (Missing Data Procedures).

(2) A PEMS for units not subject to the requirements of 40 CFR Part 75 may use calculations in accordance with §117.8110(b) of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources).

§117.1145. Notification, Recordkeeping, and Reporting Requirements.

(a) Notification. The owner or operator of an affected unit shall submit written notification to the appropriate regional office and any local air pollution control agency having jurisdiction of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) relative accuracy test audit (RATA) conducted under §117.1140 of this title (relating to Demonstration of Compliance) at least 15 days prior to such date.

(b) Reporting of test results. The owner or operator of an affected unit shall furnish the Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction a copy of the results of any CEMS or PEMS RATA conducted under §117.1140 of this title within 60 days after completion of such testing or evaluation.

(c) Startup and shutdown records. For units subject to the startup and/or shutdown provisions of §101.222 of this title (relating to Demonstrations), hourly records must be made of startup and/or shutdown events and maintained for a period of at least two years. Records must be available for inspection by the executive director, United States Environmental Protection Agency, and any local air pollution control agency having jurisdiction upon request. These records must include, but are not limited to: type of fuel burned; quantity of each type fuel burned; gross and net energy production in megawatt-hours; and the date, time, and duration of the event.

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS or PEMS under §117.1140 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations in this division and the monitoring system performance. All reports must be postmarked or received by the 30th day following the end of each calendar semiannual period (i.e., July 30 and January 30). Written reports must include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations §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;

(2) specific identification of each period of excess emissions that occurs during startups, 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 when 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 must be stated in the report; and

(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 or PEMS 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) must 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 unit operating time for the reporting period or the CEMS or PEMS downtime for the reporting period is greater than or equal to 5.0% of the total unit operating time for the reporting period, a summary report and an excess emission report must both be submitted.

(e) Recordkeeping. The owner or operator of a unit subject to this division shall maintain records of the data specified in this subsection. Records must be kept for at least five years and must be made available upon request by authorized representatives of the executive director, United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction.

(1) The owner or operator of a unit complying with the NO_X emission specifications in §117.1105(a)(1) – (4) of this title shall maintain daily records indicating the NO_X emissions in pounds; the quantity and type of each fuel burned; the heat input in million British thermal units (MMBtu); and the rolling 30-day average NO_X emission rate in pounds per MMBtu.

(2) The owner or operator of a unit complying with the NO_X emission specification in §117.1105(a)(5) of this title shall maintain hourly records indicating the NO_X emissions in lb; the quantity and type of each fuel burned; and the heat input in MMBtu.

(3) The owner or operator complying with the NO_X emission system cap in §117.1120 of this title shall maintain daily records for each EGF in the cap indicating the NO_X emissions in pounds; the quantity and type of each fuel burned; and the heat input in MMBtu. In addition, the owner or operator shall maintain daily records indicating the total NO_X emissions in pounds from all EGFs under the system cap and the rolling 30-day average NO_X emissions rate (in pounds per day) for all EGFs under the system cap.

(4) The owner or operator of a unit using the exemption in §117.1103(1) of this title (relating to Exemptions), shall maintain monthly records indicating the quantity and type of each fuel burned, the heat input in MMBtu; and the rolling 12-month average heat input in MMBtu.

(5) The owner or operator of a unit the exemption in §117.1103(2) of this title, shall maintain monthly records indicating the operating hours and the rolling 12-month average operating hours.

(6) The owner or operator shall maintain records of records of the results of testing, evaluations, calibrations, checks, adjustments, and maintenance of a CEMS or PEMS.

§117.1152. Control Plan Procedures for Reasonably Available Control Technology (RACT).

(a) The owner or operator of any unit subject to §117.1105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) at a major source of nitrogen oxides (NO_x) shall submit a control plan report to demonstrate compliance with the requirements of §117.1105 of this title. The report must include:

(1) the rule section used to demonstrate compliance, either §117.1105 of this title; §117.1120 of this title (relating to System Cap); or §117.9800 of this title (relating to Use of Emission Credits for Compliance);

(2) the specific rule citation for any unit with a claimed exemption from the emission specification of §117.1105 of this title;

(3) for each affected unit: the method of NO_x control, the method of monitoring emissions, and the method of providing substitute emissions data when the NO_x monitoring system is not providing valid data; and

(4) for sources complying with §117.1120 of this title, detailed calculation of the system cap that includes all data relied on for each electric generating facility included in the system cap equation in §117.1120(c) of this title.

(b) The report must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Office of Air by the applicable date specified for control plans in §117.9110 of this title (relating to Compliance Schedule for Bexar County Utility Electric Generation Sources).

(c) For any unit that becomes subject to §117.1105 of this title after the applicable date specified for submission of control plans in §117.9110 of this title, the control plan must be submitted to the Office of Compliance and Enforcement, the appropriate regional office, and the Office of Air no later than 60 days after becoming subject to §117.1105 of this title.

(d) If any of the information changes in a control plan report submitted in accordance with subsection (b) or (c) of this section, including functionally identical replacements, the control plan must be updated no later than 60 days after the change occurs. Written or electronic records of the updated control plan must be kept for a period of at least five years and must be made available upon request by authorized representatives of the executive director, the United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction.

SUBCHAPTER D: COMBUSTION CONTROL AT MINOR SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 1: HOUSTON-GALVESTON-BRAZORIA OZONE NONATTAINMENT AREA MINOR SOURCES

§§117.2010, 117.2035

Statutory Authority

The amended rules are proposed under Texas Water Code (TWC), §5.102, concerning general powers; §5.103, concerning Rules; TWC, §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; TWC, §7.002, concerning Enforcement Authority, which authorizes the commission to enforce the provisions of the Water Code and the Health and Safety Code within the commission's jurisdiction; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The amendments are also proposed under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning the State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants; and THSC, §382.021, concerning Sampling Methods and Procedures.

The proposed amendments implement TWC, §§5.102, 5.103 and 7.002; and THSC, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.021.

§117.2010. Emission Specifications.

(a) For sources that are subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the nitrogen oxides (NO_x) emission rate values used to determine allocations for Chapter 101, Subchapter H, Division 3 of this title must be the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001, that the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications in subsection (c) of this section. The averaging time must be as specified in Chapter 101, Subchapter H, Division 3 of this title.

(b) For sources that are not subject to Chapter 101, Subchapter H, Division 3 of this title, NO_x emissions are limited to the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001, that the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications in subsection (c) of this section. The averaging time must be as follows:

(1) if the unit is operated with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.2035(c) of this title (relating to Monitoring and Testing Requirements), either as:

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

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

(C) a block one-hour average, in pounds per hour, for boilers and process heaters, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable limit in pounds per million British thermal units (lb/MMBtu); or

(2) if the unit is not operated with a NO_x CEMS or PEMS under §117.2035(c) of this title, a block one-hour average, in the units of the applicable standard.

(c) The following NO_x emission specifications must be used in conjunction with subsection (a) of this section to determine allocations for Chapter 101, Subchapter H, Division 3 of this title, or in conjunction with subsection (b) of this section to establish unit-by-unit emission specifications, as appropriate:

(1) from boilers and process heaters:

(A) gas-fired, 0.036 lb/MMBtu heat input (or alternatively, 30 parts per million by volume (ppmv) at 3.0% oxygen (O_2), dry basis); and

(B) liquid-fired, 0.072 lb/MMBtu heat input (or alternatively, 60 ppmv at 3.0% O_2, dry basis);

(2) from stationary, gas-fired, reciprocating internal combustion engines:

(A) fired on landfill gas, 0.60 gram per horsepower-hour (g/hp-hr); and

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

(3) from stationary, dual-fuel, reciprocating internal combustion engines, 5.83 g/hp-hr;

(4) from stationary, diesel, reciprocating internal combustion engines:

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

(B) for engines not subject to subparagraph (A) of this paragraph:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(5) from stationary gas turbines (including duct burners), 0.15 lb/MMBtu; and

(6) as an alternative to the emission specifications in paragraphs (1) - (5) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu heat input. For units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor must be used to determine whether the unit is eligible for the emission specification of this paragraph. For units placed into service after January 1, 1997, the annual capacity factor must be calculated from two consecutive years in the first five years of operation to determine whether the unit is eligible for the emission specification of this paragraph, using the same two consecutive years chosen for the activity level baseline. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title (relating to Definitions).

(d) The maximum rated capacity used to determine the applicability of the emission specifications in subsection (c) of this section must be:

(1) the greater of the following:

(A) the maximum rated capacity as of December 31, 2000; or

(B) the maximum rated capacity after December 31, 2000; or

(2) alternatively, the maximum rated capacity authorized by a permit issued under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) on or after January 2, 2001, for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, provided that the maximum rated capacity authorized by the permit issued on or after January 2, 2001, is no less than the maximum rated capacity represented in the permit application as of January 2, 2001.

(e) A unit's classification is determined by the most specific classification applicable to the unit as of December 31, 2000. For example, a unit that is classified as a stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, is classified as a stationary gas-fired engine for the purposes of this chapter.

(f) Changes after December 31, 2000, to a unit subject to an emission specification in subsection (c) of this section (ESAD unit) that result in increased NO_x emissions from a unit not subject to an emission specification in subsection (c) of this section (non-ESAD unit), such as redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator or a flare, is only allowed if:

(1) the increase in NO_X emissions at the non-ESAD unit is determined using a CEMS or PEMS that meets the requirements of §117.2035(c) of this title, or through stack testing that meets the requirements of §117.2035(e) of this title; and

(2) either of the following conditions is met:

(A) for sources that are subject to Chapter 101, Subchapter H, Division 3 of this title, a deduction in allowances equal to the increase in NO_X emissions at the non-ESAD unit is made as specified in §101.354 of this title (relating to Allowance Deductions); or

(B) for sources that are not subject to Chapter 101, Subchapter H, Division 3 of this title, emission credits equal to the increase in NO_X emissions at the non-ESAD unit are obtained and used in accordance with §117.9800 of this title (relating to Use of Emission Credits for Compliance).

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

(h) The availability under subsection (c)(6) of this section of an emission specification for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. Reduced operation after December 31, 2000, cannot be used to qualify for a more lenient emission specification under subsection (c)(6) of this section than would otherwise apply to the unit.

(i) No person shall allow the discharge into the atmosphere from any unit subject to NO_X emission specifications in subsection (c) of this section, emissions in excess of the following, except as provided in §117.2025 of this title (relating to Alternative Case Specific Specifications):

(1) carbon monoxide (CO), 400 ppmv at 3.0% O_2, dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines):

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

(B) on a one-hour average, for units not equipped with CEMS or PEMS for CO; and

(2) for units that inject urea or ammonia into the exhaust stream for NO_X control, ammonia emissions of 10 ppmv at 3.0% O_2, dry, for boilers and process heaters; 15% O_2, dry, for stationary gas turbines (including duct burners used in turbine exhaust ducts), [and] gas-fired lean-burn engines, and diesel engines; and 3.0% O_2, dry, for all other units, based on:

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

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

§117.2035. Monitoring and Testing Requirements.

(a) Totalizing fuel flow meters.

(1) The owner or operator of each unit subject to §117.2010 of this title (relating to Emission Specifications) and subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), or of each unit claimed exempt under §117.2003(b) of this title (relating to Exemptions) shall install, calibrate, maintain, and operate totalizing fuel flow meters with an accuracy of ± 5%, to individually and continuously measure the gas and liquid fuel usage. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The owner or operator of units with totalizing fuel flow meters installed prior to March 31, 2005, that do not meet the accuracy requirements of this subsection shall either recertify or replace existing meters to meet the ± 5% accuracy required as soon as practicable, but no later than March 31, 2007. For the purpose of compliance with this subsection for units having pilot fuel supplied by a separate fuel system or from an unmonitored portion of the same fuel system, the fuel flow to pilots may be calculated using the manufacturer's design flow rates rather than measured with a fuel flow meter. The calculated pilot fuel flow rate must be added to the monitored fuel flow when fuel flow is totaled.

(2) The following are alternatives to the fuel flow monitoring requirements of this subsection.

(A) Units operating with a nitrogen oxides (NO_X) and diluent continuous emissions monitoring system (CEMS) under subsection (c) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (CFR) Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

(B) Units that vent to a common stack with a NO_X and diluent CEMS under subsection (c) of this section may use a single totalizing fuel flow meter.

(C) Diesel engines operating with run time meters may meet the fuel flow monitoring requirements of this subsection through monthly fuel use records.

(D) Units of the same category of equipment subject to Chapter 101, Subchapter H, Division 3 of this title may share a single totalizing fuel flow meter provided:

(i) the owner or operator performs a stack test in accordance with subsection (e) of this section for each unit sharing the totalizing fuel flow meter; and

(ii) the testing results from the unit with the highest emission rate (in pounds per million British thermal units or grams per horsepower-hour) are used for reporting purposes in §101.359 of this title (relating to Reporting) for all units sharing the totalizing fuel flow meter.

(E) The owner or operator of a unit or units claimed exempt under §117.2003(b) of this title, located at an independent school district may demonstrate compliance with the exemption by the following:

(i) in addition to the records required by §117.2045(a)(1) of this title (relating to Recordkeeping and Reporting Requirements), maintain the following monthly records in either electronic or written format. These records must be kept for a period of at least five years and must be made available upon request by authorized representatives of the executive director, the United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction;

(I) total fuel usage for the entire site;

(II) the estimated hours of operation for each unit;

(III) the estimated average operating rate (e.g., a percentage of maximum rated capacity) for each unit; and

(IV) the estimated fuel usage for each unit; and

(ii) within 60 days of written request by the executive director, submit for review and approval all methods, engineering calculations, and process information used to estimate the hours of operation, operating rates, and fuel usage for each unit.

(F) The owner or operator of units claimed exempt under §117.2003(b) of this title may share a single totalizing fuel flow meter to demonstrate compliance with the exemption, provided that:

(i) all affected units at the site qualify for the exemption under §117.2003(b) of this title; and

(ii) the total fuel usage for all units at the site is less than:

(I) the annual fuel usage limitation in §117.2003(b)(1) of this title; or

(II) the annual fuel usage limitation in §117.2003(b)(2) of this title when all affected units at the site are equal to or greater than 5.0 million British thermal units per hour.

(G) Stationary reciprocating internal combustion engines and stationary gas turbines equipped with a continuous monitoring system that continuously monitors horsepower and hours of operation are not required to install totalizing fuel flow meters. The continuous monitoring system must be installed, calibrated, maintained, and operated according to manufacturer's procedures.

(b) Oxygen (O_2) monitors. If the owner or operator installs an O_2 monitor, the criteria in §117.8100(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources) should be considered the appropriate guidance for the location and calibration of the monitor.

(c) NO_X monitors. If the owner or operator installs a CEMS or predictive emissions monitoring system (PEMS), it must meet the requirements of §117.8100(a) or (b) of this title. If a PEMS is used, the PEMS must predict the pollutant emissions in the units of the applicable emission specifications of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Minor Sources).

(d) Monitor installation schedule. Installation of monitors must be performed in accordance with the schedule specified in §117.9200 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Minor Sources).

(e) Testing requirements. The owner or operator of any unit subject to §117.2010 of this title shall comply with the following testing requirements.

(1) Each unit must be tested for NO_X, carbon monoxide (CO), and O_2 emissions.

(2) One of the ammonia monitoring procedures specified in §117.8130 of this title (relating to Ammonia Monitoring) must be used to demonstrate compliance with the ammonia emission specification of §117.2010(i)(2) of this title for units that inject urea or ammonia into the exhaust stream for NO_X control. <u>This paragraph does not apply to stationary diesel engines equipped with selective catalytic reduction (SCR) systems that meet the following criteria.</u>

(A) The SCR system must use a reductant other than the engine's fuel.

(B) The SCR system must operate with a diagnostic system that monitors reductant quality and tank levels.

(C) The diagnostic system must alert owners or operators to the need to refill the reductant tank before it is empty or to replace the reductant if the reductant does not meet applicable concentration specifications.

(D) If the SCR system uses input from an exhaust NO_X sensor (or other sensor) to alert owners or operators when the reductant quality is inadequate, the reductant quality does not need to be monitored separately by the diagnostic system.

(E) The reductant tank level must be monitored in accordance with the manufacturer's design to demonstrate compliance with this paragraph.

(F) The method of alerting an owner or operator must be a visual or audible alarm.

(3) For units not equipped with CEMS or PEMS, all testing must be conducted according to §117.8000 of this title (relating to Stack Testing Requirements). In lieu of the test methods specified in §117.8000 of this title, the owner or operator may use American Society for Testing and Materials (ASTM) D6522-00 to perform the NO_X, CO, and O_2 testing required by this subsection on natural gas-fired reciprocating engines, combustion turbines, boilers, and process heaters. If the owner or operator elects to use ASTM D6522-00 for the testing

requirements, the report must contain the information specified in §117.8010 of this title (relating to Compliance Stack Test Reports).

(4) Test results must be reported in the units of the applicable emission specifications and averaging periods. If compliance testing is based on 40 CFR Part 60, Appendix A reference methods, the report must contain the information specified in §117.8010 of this title.

(5) For units equipped with CEMS or PEMS, the CEMS or PEMS must be installed and operational before testing under this subsection. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(6) Initial compliance with §117.2010 of this title for units operating with CEMS or PEMS must be demonstrated after monitor certification testing using the NOX CEMS or PEMS.

(7) For units not operating with CEMS or PEMS, the following apply.

(A) Retesting as specified in paragraphs (1) - (4) of this subsection is required within 60 days after any modification that could reasonably be expected to increase the NO_x emission rate.

(B) Retesting as specified in paragraphs (1) - (4) of this subsection may be conducted at the discretion of the owner or operator after any modification that could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation, and fuel-lean and conventional (fuel-rich) reburn.

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

(8) Testing must be performed in accordance with the schedule specified in §117.9200 of this title.

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

(f) Emission allowances.

(1) For sources that are subject to Chapter 101, Subchapter H, Division 3 of this title, the NO_x testing and monitoring data of subsections (a) - (e) of this section, together with the level of activity, as defined in §101.350 of this title (relating to Definitions), must be used to establish the emission factor calculating actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(2) The emission factor in subsection (e)(7) of this section or paragraph (1) of this subsection is multiplied by the unit's level of activity to determine the unit's actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(g) Run time meters. The owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.2003(a)(2)(E), (H), or (I) of this title shall record the operating time with an elapsed run time meter. Any run time meter installed on or after October 1, 2001, must be non-resettable.

SUBCHAPTER D: COMBUSTION CONTROL AT MINOR SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 2: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MINOR SOURCES

§§117.2110, 117.2135

Statutory Authority

The amended rules are proposed under Texas Water Code (TWC), §5.102, concerning general powers; §5.103, concerning Rules; TWC, §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; TWC, §7.002, concerning Enforcement Authority, which authorizes the commission to enforce the provisions of the Water Code and the Health and Safety Code within the commission's jurisdiction; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The amendments are also proposed under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning the State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants; and THSC, §382.021, concerning Sampling

Methods and Procedures.

The proposed amendments implement TWC, §§5.102, 5.103 and 7.002; and THSC, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.021.

§117.2110. Emission Specifications for Eight-Hour Attainment Demonstration.

(a) The owner or operator of any source subject to this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources) shall not allow the discharge into the atmosphere emissions of nitrogen oxides (NO_x) in excess of the following emission specifications.

(1) Emission specifications for stationary, gas-fired, reciprocating internal combustion engines are as follows:

(A) rich-burn engines:

(i) fired on landfill gas, 0.60 grams per horsepower-hour (g/hp-hr); and

(ii) all other rich-burn engines, 0.50 g/hp-hr; and

(B) lean-burn engines:

(i) placed into service before June 1, 2007, that have not been modified, reconstructed, or relocated on or after June 1, 2007, 0.70 g/hp-hr; and

(ii) placed into service, modified, reconstructed, or relocated on or after June 1, 2007:

(I) fired on landfill gas or other biogas, 0.60 g/hp-hr; and

(II) all other lean-burn engines, 0.50 g/hp-hr.

(2) The emission specification for stationary, dual-fuel, reciprocating internal combustion engines is 5.83 g/hp-hr.

(3) Emission specifications for stationary, diesel, reciprocating internal combustion engines are as follows:

(A) placed into service before March 1, 2009, that have not been modified, reconstructed, or relocated on or after March 1, 2009, the lower of 11.0 g/hp-hr or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data; and

(B) for engines not subject to subparagraph (A) of this paragraph:

(i) with a horsepower (hp) rating of 50 hp or greater, but less than 100 hp, that are installed, modified, reconstructed, or relocated on or after March 1, 2009, 3.3 g/hp-hr;

(ii) with a horsepower rating of 100 hp or greater, but less than or equal to 750 hp, that are installed, modified, reconstructed, or relocated on or after March 1, 2009, 2.8 g/hp-hr; and

(iii) with a horsepower rating of 750 hp or greater that are installed, modified, reconstructed, or relocated on or after March 1, 2009, 4.5 g/hp-hr.

(4) As an alternative to the emission specifications in paragraphs (1) - (3) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 pound per million British thermal units (lb/MMBtu) heat input. For units placed into service on or before December 31, 2000, the annual capacity factor as of December 31, 2000, must be used to determine eligibility for the alternative emission specification of this paragraph. For units placed into service after December 31, 2000, a 12-month rolling average must be used to determine the annual capacity factor.

(5) For the purposes of this subsection, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account.

(b) The averaging time for the NO_x emission specifications of subsection (a) of this section is as follows:

(1) if the unit is operated with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.2135(c) of this title (relating to Monitoring, Notification, and Testing Requirements), either as:

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

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

(C) a block one-hour average, in pounds per hour, for boilers, calculated as the product of the boiler's maximum rated capacity and its applicable limit in lb/MMBtu; or

(2) if the unit is not operated with a NO_x CEMS or PEMS under §117.2135(c) of this title, a block one-hour average, in the units of the applicable standard.

(c) The maximum rated capacity used to determine the applicability of the emission specifications in subsection (a) of this section must be the greater of the following:

(1) the maximum rated capacity as of December 31, 2000; or

(2) the maximum rated capacity after December 31, 2000.

(d) A unit's classification is determined by the most specific classification applicable to the unit as of December 31, 2000. For example, a unit that is classified as a stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, must be classified as a stationary gas-fired engine for the purposes of this chapter.

(e) Changes after December 31, 2000, to a unit subject to an emission specification in subsection (a) of this section (ESAD unit) that result in increased NO_x emissions from a unit not subject to an emission specification in subsection (a) of this section (non-ESAD unit), such as redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator or a flare, is only allowed if:

(1) the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS that meets the requirements of §117.2135(c) of this title, or through stack testing that meets the requirements of §117.2135(f) of this title; and

(2) emission credits equal to the increase in NOX emissions at the non-ESAD unit are obtained and used in accordance with §117.9800 of this title (relating to Use of Emission Credits for Compliance).

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

(g) The availability under subsection (a)(4) of this section of an emission specification for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. Reduced operation after December 31, 2000, cannot be used to qualify for a more lenient emission specification under subsection (a)(4) of this section than would otherwise apply to the unit.

(h) No person shall allow the discharge into the atmosphere from any unit subject to NO_X emission specifications in subsection (a) of this section, emissions in excess of the following, except as provided in §117.2125 of this title (relating to Alternative Case Specific Specifications):

(1) carbon monoxide (CO), 400 ppmv at 3.0% oxygen (O_2), dry basis (or alternatively, 3.0 g/hp-hr for stationary internal combustion engines):

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

(B) on a one-hour average, for units not equipped with CEMS or PEMS for CO; and

(2) for units that inject urea or ammonia into the exhaust stream for NO_X control, ammonia emissions of 10 ppmv at 15% O_2, dry, for gas-fired lean-burn engines and diesel engines; and 3.0% O_2, dry, for all other units, based on:

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

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

(i) An owner or operator may use emission reduction credits as specified in §117.9800 of this title to comply with the NO_x emission specifications of this section.

§117.2135. Monitoring, Notification, and Testing Requirements.

(a) Oxygen (O_2) monitors. If the owner or operator installs an O_2 monitor, the criteria in §117.8100(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources) should be considered the appropriate guidance for the location and calibration of the monitor.

(b) Nitrogen oxides (NO_x) monitors. If the owner or operator installs a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS), the CEMS or PEMS must meet the requirements of §117.8100(a) or (b) of this title. If a PEMS is used, the PEMS must predict the pollution emissions in the units of the applicable emission limitations of this division.

(c) Monitor installation schedule. Installation of monitors must be performed in accordance with the schedule specified in §117.9210 of this title (relating to Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources).

(d) Testing requirements. The owner or operator of any unit subject to §117.2110 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) shall comply with the following testing requirements.

(1) Each unit must be tested for NO_X, carbon monoxide (CO), and O_2 emissions.

(2) One of the ammonia monitoring procedures specified in §117.8130 of this title (relating to Ammonia Monitoring) must be used to demonstrate compliance with the ammonia emission specification of §117.2110(h)(2) of this title for units that inject urea or ammonia into the exhaust stream for NO_X control. This paragraph does not apply to stationary diesel engines equipped with selective catalytic reduction (SCR) systems that meet all of the following criteria.

(A) The SCR system must use a reductant other than the engine's fuel.

(B) The SCR system must operate with a diagnostic system that monitors reductant quality and tank levels.

(C) The diagnostic system must alert owners or operators to the need to refill the reductant tank before it is empty or to replace the reductant if the reductant does not meet applicable concentration specifications.

(D) If the SCR system uses input from an exhaust NO_X sensor (or other sensor) to alert owners or operators when the reductant quality is inadequate, the reductant quality does not need to be monitored separately by the diagnostic system.

(E) The reductant tank level must be monitored in accordance with the manufacturer's design to demonstrate compliance with this paragraph.

(F) The method of alerting an owner or operator must be a visual or audible alarm.

(3) For units not equipped with CEMS or PEMS, all testing must be conducted according to §117.8000 of this title (relating to Stack Testing Requirements). In lieu of the test methods specified in §117.8000 of this title, the owner or operator may use American Society for Testing and Materials (ASTM) D6522-00 to perform the NO_X, CO, and O_2 testing required by this subsection on natural gas-fired reciprocating engines. If the owner or operator elects to use ASTM D6522-00 for the testing requirements, the report must contain the information specified in §117.8010 of this title (relating to Compliance Stack Test Reports).

(4) Test results must be reported in the units of the applicable emission specifications and averaging periods. If compliance testing is based on 40 Code of Federal Regulations Part 60, Appendix A reference methods, the report must contain the information specified in §117.8010 of this title.

(5) For units equipped with CEMS or PEMS, the CEMS or PEMS must be installed and operational before testing under this subsection. Verification of operational status must, at a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(6) Initial compliance with the emission specifications of §117.2110 of this title for units operating with CEMS or PEMS must be demonstrated after monitor certification testing using the NO_X CEMS or PEMS.

(7) For units not operating with CEMS or PEMS, the following apply.

(A) Retesting as specified in paragraphs (1) - (4) of this subsection is required within 60 days after any modification that could reasonably be expected to increase the NO_X emission rate.

(B) Retesting as specified in paragraphs (1) - (4) of this subsection may be conducted at the discretion of the owner or operator after any modification that could reasonably be expected to decrease the NO_X emission rate, including, but not limited to, installation of post-combustion controls, low-NO_X burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation, and fuel-lean and conventional (fuel-rich) reburn.

(C) Stationary, reciprocating internal combustion engines not equipped with CEMS or PEMS must be periodically tested for NO_x and CO emissions as specified in §117.8140(a) of this title (relating to Emission Monitoring for Engines).

(8) Testing must be performed in accordance with the schedule specified in §117.9210 of this title.

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

(10) The owner or operator of an affected unit in the Dallas-Fort Worth eight-hour ozone nonattainment area must submit written notification of any CEMS or PEMS relative accuracy test audit (RATA) or testing required under this section to the appropriate regional office and any local air pollution control agency having jurisdiction at least 15 days in advance of the date of RATA or testing.

(e) Run time meters. The owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.2103(5), (8), (9), or (10) of this title (relating to Exemptions) shall record the operating time with a non-resettable elapsed run time meter.

SUCHAPTER E: MULTI-REGION COMBUSTION CONTROL

DIVISION 1: UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS

§117.3000

Statutory Authority

The amended rules are proposed under Texas Water Code (TWC), §5.102, concerning general powers; §5.103, concerning Rules; TWC, §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; TWC, §7.002, concerning Enforcement Authority, which authorizes the commission to enforce the provisions of the Water Code and the Health and Safety Code within the commission's jurisdiction; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The amendments are also proposed under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning the State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants; and THSC, §382.021, concerning Sampling Methods and Procedures.

The proposed amendments implement TWC, §§5.102, 5.103 and 7.002; and THSC, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.021.

§117.3000. Applicability.

(a) The provisions of this division (relating to Utility Electric Generation in East and Central Texas) apply to each utility electric power boiler and stationary gas turbine (including duct burners used in turbine exhaust ducts) that:

(1) generates electric energy for compensation;

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

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

(4) is located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, or Wharton County.

(b) The provisions of §117.3005 of this title (relating to Gas-Fired Steam Generation) also apply in Palo Pinto County.

(c) This division no longer applies in Bexar County after December 31, 2024.

SUCHAPTER E: MULTI-REGION COMBUSTION CONTROL

DIVISION 2: CEMENT KILNS

§§117.3103, 117.3110, 117.3120, 117.3124, 117.3145

Statutory Authority

The new and amended rules are proposed under Texas Water Code (TWC), §5.102, concerning general powers; §5.103, concerning Rules; TWC, §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; TWC, §7.002, concerning Enforcement Authority, which authorizes the commission to enforce the provisions of the Water Code and the Health and Safety Code within the commission’s jurisdiction; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new and amended rules are also proposed under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning the State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants; and THSC, §382.021, concerning Sampling Methods and Procedures.

The proposed new and amended rules implement TWC, §§5.102, 5.103 and 7.002; and THSC, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.021.

§117.3103. Exemptions.

(a) Portland cement kilns exempted from the provisions of this division (relating to Cement Kilns), include any portland cement kiln placed into service on or after December 31, 1999, except as specified in §§117.3110, 117.3120, [and] 117.3123, and 117.3124 of this title (relating to Emission Specifications; Source Cap; [and] Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements; and Bexar County Control Requirements for Reasonably Available Control Technology (RACT)).

(b) Any account in Ellis County with no portland cement kilns in operation prior to January 1, 2001, is exempt from §117.3123 of this title.

(c) After the compliance date specified in §117.9320(c) of this title (relating to Compliance Schedule for Cement Kilns), portland cement kilns that are subject to §117.3123 of this title are exempt from §117.3110 and §117.3120 of this title between March 1 and October 31 of each calendar year.

(d) After the compliance date specified in §117.9320(c) of this title, portland cement kilns that are subject to §117.3124 of this title are exempt from §117.3110 and §117.3120 of this title.

§117.3110. Emission Specifications.

(a) In accordance with the compliance schedule in §117.9320 of this title (relating to Compliance Schedule for Cement Kilns), the owner or operator of each portland cement kiln shall ensure that nitrogen oxides (NO_x) emissions do not exceed the following rates on a 30-day rolling average. For the purposes of this section, the 30-day rolling average is calculated as the total of all the hourly emissions data (in pounds) that fuel was combusted in a cement kiln in the preceding 30 consecutive days, divided by the total number of tons of clinker produced in that kiln during the same 30-day period:

(1) for each long wet kiln:

(A) in Bexar, Comal, Hays, and McLennan Counties, 6.0 pounds per ton (lb/ton) of clinker produced; and

(B) in Ellis County, 4.0 lb/ton of clinker produced;

(2) for each long dry kiln, 5.1 lb/ton of clinker produced;

(3) for each preheater kiln, 3.8 lb/ton of clinker produced; and

(4) for each preheater-precalciner or precalciner kiln, 2.8 lb/ton of clinker produced.

(b) If there are multiple cement kilns at the same account, the owner or operator may choose to comply with the emission specifications of subsection (a) of this section on the basis of a weighted average for the cement kilns at the account that are subject to the same specification. Each owner or operator choosing this option shall submit written notification of this choice to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction before the appropriate compliance date in §117.9320 of this title.

(c) Each long wet or long dry kiln for which the following controls are installed and operated during kiln operation is not required to meet the NO_X emission specifications of subsection (a) of this section, provided that each owner or operator choosing this option submits written notification of this choice to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction before the appropriate compliance date in §117.9320 of this title:

(1) a low-NO_X burner and either:

(A) mid-kiln firing; or

(B) some other form of secondary combustion achieving equivalent levels of NO_X reductions; or alternatively;

(2) other additions or changes to the kiln system achieving at least a 30% reduction in NO_X emissions, provided the additions or changes are approved by the executive director with concurrence from the United States Environmental Protection Agency.

(d) Each preheater or precalciner kiln for which either a low-NO_x burner or a low-NO_x precalciner is installed and operated during kiln operation is not required to meet the NO_x emission specifications of subsection (a) of this section. Each owner or operator choosing this option shall submit written notification of this choice to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction before the appropriate compliance date in §117.9320 of this title.

(e) An owner or operator may use §117.9800 of this title (relating to Use of Emission Credits for Compliance) to meet the NO_x emission control requirements of this section, in whole or in part.

(f) This section no longer applies in Bexar County after December 31, 2024.

§117.3120. Source Cap.

(a) As an alternative to complying with the requirements of §117.3110 of this title (relating to Emission Specifications) in Bexar, Comal, Ellis, Hays, and McLennan Counties, an owner or operator may reduce total nitrogen oxides (NO_x) emissions (in pounds per day (ppd)) from all cement kilns at the account (including any cement kilns placed into service on or after December 31, 1999) to at least 30% less than the total NO_x emissions (in ppd) from all cement kilns in the account's 1996 emissions inventory (EI), on a 90-day rolling average basis. For the purposes of this section, the 90-day rolling average is calculated as the total of all the hourly emissions data for the preceding 90 days. For the calendar year that includes the appropriate compliance date in §117.9320 of this title (relating to Compliance Schedule for Cement Kilns), only hourly emissions data on or after that compliance date is included, such that the first 90-day period ends 90 days after the appropriate compliance date in §117.9320 of this title. A 90-day rolling average emission cap must be calculated using the following equation.

Figure: 30 TAC §117.3120(a) (no change)

(b) To qualify for the source cap option available under this section, the owner or operator shall submit an initial control plan to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction that demonstrates that the overall reduction of NO_X emissions from all cement kilns at the account will be at least 30% from the 1996 baseline EI on a 90-day rolling average basis. The plan must be submitted no later than December 31 of the year preceding the appropriate compliance date in §117.9320 of this title. Each control plan must be approved by the executive director before the owner or operator may use the source cap available under this section for compliance. At a minimum, the control plan must include the emission point number (EPN), facility identification number (FIN), and 1996 baseline EI NO_X emissions (in ppd) from each cement kiln at the account; a description of the control measures that have been or will be implemented at each cement kiln; and an explanation of the recordkeeping procedure and calculations that will be used to demonstrate compliance.

(c) Beginning on March 31 of the year following the appropriate compliance date in §117.9320 of this title, the owner or operator shall submit an annual report no later than March 31 of each year to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction that demonstrates that the overall reduction of NO_X emissions from all cement kilns at the account is at least 30% from the 1996 baseline EI on a 90-day rolling average basis. At a minimum, the report must include the EPN, FIN, and each 90-day rolling average NO_X emissions (in ppd) during the preceding calendar year for the cement kilns at the account.

(d) All representations in control plans and annual reports become enforceable conditions. The owner or operator shall not vary from such representations if the variation will cause a change in the identity of the specific cement kilns subject to this section or the method of control of emissions unless the owner or operator submits a revised control plan to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction no later than 30 days after the change. All control plans and reports must demonstrate that the total NO_X emissions (in ppd) from all cement kilns at the account (including any cement kilns placed into service on or after December 31, 1999) are being reduced to at least 30% less than the total NO_X emissions (in ppd) from all cement kilns in the account's 1996 EI on a 90-day rolling average basis.

(e) The NO_X emissions monitoring required by §117.3140 of this title (relating to Continuous Demonstration of Compliance) for each cement kiln in the source cap must be used to demonstrate continuous compliance with the source cap.

(f) An owner or operator may use §117.9800 of this title (relating to Use of Emission Credits for Compliance) to meet the NO_X emission control requirements of this section, in whole or in part.

(g) This section no longer applies in Bexar County after December 31, 2024.

§117. 3124. Bexar County Control Requirements for Reasonably Available Control Technology (RACT).

(a) In accordance with the applicable schedule in §117.9320 of this title (relating to Compliance Schedule for Cement Kilns), the owner or operator of each portland cement kiln located in Bexar County shall ensure that nitrogen oxides (NO_x) emissions from each preheater-precalciner or precalciner kiln do not exceed 2.8 pounds per ton (lb/ton) of clinker produced on a rolling 30-day average basis.

(b) For the purposes of this section, the rolling 30-day average is an average, calculated for each day that fuel was combusted in the cement kiln, as the total of all the hourly emissions data (in pounds) for the preceding 30 days that fuel was combusted in the cement kiln, divided by the total number of tons of clinker produced in that kiln during the same 30-day period.

(c) An owner or operator may use §117.9800 of this title (relating to Use of Emission Credits for Compliance) to meet the NO_x emission control requirements of this section, in whole or in part.

§117.3145. Notification, Recordkeeping, and Reporting Requirements.

(a) Notification. The owner or operator of each portland cement kiln shall submit verbal notification to the executive director of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) performance evaluation conducted under §117.3140 or §117.3142 of this title (relating to Continuous Demonstration of Compliance; and Emission Testing and Monitoring for Eight-Hour Attainment Demonstration) at least 15 days before such date followed by written notification within 15 days after testing is completed.

(b) Reporting of test results. The owner or operator of each portland cement kiln shall furnish the executive director and any local air pollution control agency having jurisdiction a copy of any CEMS or PEMS relative accuracy test audit conducted under §117.3140 or §117.3142 of this title:

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

(2) not later than the appropriate compliance date in §117.9320 of this title (relating to Compliance Schedule for Cement Kilns).

(c) Recordkeeping. The owner or operator of a portland cement kiln subject to the requirements of this division (relating to Cement Kilns) shall maintain written or electronic records of the data specified in this subsection. Such records must be kept for a period of at least five years and must be made available upon request by authorized representatives of the executive director, United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction. The records must include:

(1) for each kiln subject to §117.3110 or 117.3120 of this title (relating to Emission Specifications; and Source Cap), monitoring records of:

(A) daily and rolling 30-day average (and, for each kiln subject to the source cap in §117.3120 of this title, rolling 90-day average) nitrogen oxides (NO_X) emissions (in pounds);

(B) daily and rolling 30-day average (and, for each kiln subject to the source cap in §117.3120 of this title, rolling 90-day average) production of clinker (in United States short tons); and

(C) average NO_X emission rate (in pounds per ton (lb/ton) of clinker produced) on the basis of a rolling 30-day average (and, for each kiln subject to the source cap in §117.3120 of this title, a rolling 90-day average);

(2) records of the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS and PEMS;

(3) records of the results of any stack testing conducted; [and]

(4) for each kiln subject to the source cap in §117.3123 of this title (relating to Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements) and emission testing and monitoring requirements in §117.3142 of this title:

(A) records of the control plan required under §117.3123 of this title;

(B) hourly records of the average NO_X concentration in parts per million by volume;

(C) hourly records of the NO_x emissions in pounds per hour;

(D) daily records of the NO_x emissions in tons per day;

(E) daily records of the NO_x emissions in tons per day expressed as a 30-day rolling average;

(F) hourly records of the average exhaust gas flow rate in dry standard cubic feet per minute; and

(G) records of ammonia monitoring required under §117.3142(a)(3) of this title; and [.]

(5) for each kiln subject to §117.3124 of this title (relating to Bexar County Control Requirements for Reasonably Available Control Technology (RACT)), monitoring records of:

(A) hourly, daily, and rolling 30-day average NO_x emissions (in pounds);

(B) hourly, daily, and rolling 30-day average production of clinker (in United States short tons); and

(C) rolling 30-day average NO_x emission rate (in pounds per ton of clinker produced).

SUBCHAPTER H: ADMINISTRATIVE PROVISIONS

DIVISION 1: COMPLIANCE SCHEDULES

§§117.9010, 117.9030, 117.9110, 117.9300, 117.9320

Statutory Authority

The new and amended rules are proposed under Texas Water Code (TWC), §5.102, concerning general powers; §5.103, concerning Rules; TWC, §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; TWC, §7.002, concerning Enforcement Authority, which authorizes the commission to enforce the provisions of the Water Code and the Health and Safety Code within the commission's jurisdiction; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The new and amended rules are also proposed under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning the State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants; and THSC, §382.021, concerning Sampling Methods and Procedures.

The proposed new and amended rules implement TWC, §§5.102, 5.103 and 7.002; and THSC, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.021.

§117.9010. Compliance Schedule for Bexar County Ozone Nonattainment Area Major Sources.

(a) The owner or operator of any stationary source of nitrogen oxides (NO_x) in the Bexar County ozone nonattainment area that is a major source of NO_x and is subject to the requirements of Subchapter B, Division 2 of this chapter (relating to Bexar County Ozone Nonattainment Area Major Sources) shall comply with the requirements of Subchapter B, Division 2 of this chapter as soon as practicable, but no later than January 1, 2025.

(b) The owner or operator of any stationary source of NO_x that becomes subject to the requirements of Subchapter B, Division 2 of this chapter on or after the applicable compliance date specified in subsection (a) of this section, shall comply with the requirements of Subchapter B, Division 2 of this chapter as soon as practicable, but no later than 60 days after becoming subject.

§117.9030. Compliance Schedule for Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources.

(a) Reasonably available control technology emission specifications.

(1) The owner or operator of any stationary source of nitrogen oxides (NO_x) in the Dallas-Fort Worth eight-hour ozone nonattainment area that is a major source of NO_x and is

subject to §117.405(a) or (b) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) shall comply with the requirements of Subchapter B, Division 4 of this chapter (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources) as follows:

(A) for units subject to the emission specification of §117.405(a) of this title located in Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, or Tarrant Counties, or located at a source in Wise County that emits or has the potential to emit equal to or greater than 100 tons per year (tpy) of NO_X:

(i) submission of the initial control plan required by §117.450 of this title (relating to Initial Control Plan Procedures) was required by June 1, 2016;

(ii) for units subject to the emission specification of §117.405(a) of this title as of January 1, 2017, compliance with all other requirements of Subchapter B, Division 4 of this chapter was required by January 1, 2017, and these units shall continue to comply with the requirements of Subchapter B, Division 4 of this chapter; and

(iii) for units that became subject to the emission specification of §117.405(a) of this title after January 1, 2017, compliance is required as specified in paragraph (2) of this subsection;

(B) for units subject to the emission specifications of §117.405(b) of this title located at sources in Wise County that emit or have the potential to emit equal to or greater than 100 tpy of NO_X:

(i) submission of the initial control plan required by §117.450 of this title was required by June 1, 2016;

(ii) for units subject to the emission specifications of §117.405(b) of this title as of January 1, 2017, compliance with all other requirements of Subchapter B, Division 4 of this chapter was required by January 1, 2017, and these units shall continue to comply with the requirements of Subchapter B, Division 4 of this chapter; and

(iii) for units that became subject to the emission specifications of §117.405(b) of this title after January 1, 2017, compliance is required as specified in paragraph (2) of this subsection; [and]

(C) for units subject to the emission specifications of §117.405 of this title located at sources in Wise County that emit or have the potential to emit equal to or greater than 50 tpy but less than 100 tpy of NO_X:

(i) submission of the initial control plan required by §117.450 of this title is required no later than January 15, 2021; and

(ii) for units subject to the emission specifications of §117.405 of this title, compliance with all other requirements of Subchapter B, Division 4 of this chapter is required as soon as practicable, but no later than July 20, 2021; and [.]

(D) for units subject to the emission specifications of §117.405 of this title located at sources in Wise County that emit or have the potential to emit equal to or greater than 25 tpy but less than 50 tpy of NO_X:

(i) submission of the initial control plan required by §117.450(b) of this title is required no later than May 7, 2025; and

(ii) compliance with all other requirements of Subchapter B, Division 4 of this chapter is required as soon as practicable, but no later than November 7, 2025.

(2) The owner or operator of any stationary source of NO_X that becomes subject to the requirements of §117.405 of this title on or after the applicable compliance date specified in paragraph (1) of this subsection, shall comply with the requirements of Subchapter B, Division 4 of this chapter as soon as practicable, but no later than 60 days after becoming subject.

(b) Eight-hour ozone attainment demonstration emission specifications.

(1) The owner or operator of any stationary source of NO_X in the Dallas-Fort Worth eight-hour ozone nonattainment area that is a major source of NO_X and is subject to §117.410(a) of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration) shall comply with the requirements of Subchapter B, Division 4 of this chapter as follows:

(A) submit the initial control plan required by §117.450 of this title no later than June 1, 2008; and

(B) for units subject to the emission specifications of §117.410(a) of this title, comply with all other requirements of Subchapter B, Division 4 of this chapter as soon as practicable, but no later than:

(i) March 1, 2009, for units subject to §117.410(a)(1), (2), (4), (5), (6), (7)(A), (8), (10), and (14) of this title;

(ii) March 1, 2010, for units subject to §117.410(a)(3), (7)(B), (9), (11), (12), and (13) of this title;

(C) for diesel and dual-fuel engines, comply with the restriction on hours of operation for maintenance or testing in §117.410(f) of this title, and associated recordkeeping in §117.445(f)(9) of this title (relating to Notification, Recordkeeping, and Reporting Requirements), as soon as practicable, but no later than March 1, 2009; and

(D) for any stationary gas turbine or stationary internal combustion engine claimed exempt using the exemption of §117.403(a)(7)(D), (8), or (9) of this title (relating to Exemptions), comply with the run time meter requirements of §117.440(i) of this title (relating to Continuous Demonstration of Compliance), and recordkeeping requirements of §117.445(f)(4) of this title, as soon as practicable, but no later than March 1, 2009.

(2) The owner or operator of any stationary source of NO_X that becomes subject to the requirements of Subchapter B, Division 4 of this chapter on or after the applicable compliance date specified in paragraph (1) of this subsection, shall comply with the requirements of Subchapter B, Division 4 of this chapter as soon as practicable, but no later than 60 days after becoming subject.

(3) The owner or operator of any unit that is subject to the emission specifications in §117.410(a) of this title located at sources in the Dallas-Fort Worth eight-hour ozone nonattainment area that emit or have the potential to emit equal to or greater than 25 tpy but less than 50 tpy of NO_X:

(A) submission of the initial control plan required by §117.450(b) of this title is required no later than May 7, 2025; and

(B) compliance with all other requirements of Subchapter B, Division 4 of this chapter is required as soon as practicable, but no later than November 7, 2025.

(4) The owner or operator of any stationary source of NO_X that becomes subject to the requirements of Subchapter B, Division 4 of this chapter on or after the applicable compliance date specified in paragraph (3) of this subsection, shall comply with the requirements of Subchapter B, Division 4 of this chapter as soon as practicable, but no later than 60 days after becoming subject.

§117.9110. Compliance Schedule for Bexar County Ozone Nonattainment Area Utility

Electric Generation Sources.

(a) The owner or operator of each electric utility in the Bexar County ozone nonattainment area that is subject to the requirements of Subchapter C, Division 2 of this chapter (relating to Bexar County Ozone Nonattainment Area Utility Electric Generation Sources) shall comply with the requirements of Subchapter C, Division 2 of this chapter as soon as practicable, but no later than January 1, 2025.

(b) The owner or operator of any electric utility that becomes subject to the requirements of Subchapter C, Division 2 of this chapter on or after the applicable compliance date specified in subsection (a) of this section, shall comply with the requirements of Subchapter C, Division 2 of this chapter as soon as practicable, but no later than 60 days after becoming subject.

§117.9300. Compliance Schedule for Utility Electric Generation in East and Central Texas.

(a) The owner or operator of each utility electric power boiler or stationary gas turbine located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, and Wharton Counties shall comply with the requirements of Subchapter E, Division 1 of this chapter (relating to Utility Electric Generation in East and Central Texas) as soon as practicable, but no later than the following dates:

(1) except as provided in subparagraph (C) of this paragraph, May 1, 2003, for units owned by utilities subject to the cost-recovery provisions of Texas Utilities Code, §39.263(b):

(A) the owner or operator shall use the period of May 1, 2003, through April 30, 2004, for the initial annual compliance period. Compliance for each subsequent annual period is on a calendar year basis. For example, the second annual compliance period is January 1, 2004, through December 31, 2004;

(B) the updated final control plan required by §117.3054 of this title (relating to Final Control Plan Procedures) must be submitted by May 31, 2004, and by January 31, 2005; and

(C) the owner or operator shall comply with the ammonia specification of §117.3010(2) of this title (relating to Emission Specifications) by May 1, 2005; and

(2) May 1, 2005, for all other units:

(A) the owner or operator shall use the period of May 1, 2005, through April 30, 2006, for the initial annual compliance period. Compliance for each subsequent annual period is on a calendar year basis. For example, the second annual compliance period is January 1, 2006, through December 31, 2006; and

(B) the updated final control plan required by §117.3054 of this title must be submitted by May 31, 2006, and by January 31, 2007.

(b) Beginning January 1, 2025, sources in Bexar County are no longer required to comply with the requirements of Subchapter E, Division 1 of this chapter.

§117.9320. Compliance Schedule for Cement Kilns.

(a) Except as specified in subsections[subsection] (c) and (d) of this section, the owner or operator of each portland cement kiln placed into service before December 31, 1999, in Bexar, Comal, Ellis, Hays, and McLennan Counties shall be in compliance with the requirements of Subchapter E, Division 2 of this chapter (relating to Cement Kilns) as soon as practicable, but no later than the following dates:

(1) May 1, 2003, for cement kilns in Ellis County; and

(2) May 1, 2005, for cement kilns in Bexar, Comal, Hays, and McLennan Counties.

(b) Notwithstanding subsection (a)(1) of this section, for a cement kiln in Ellis County that the owner or operator has filed an application for modification of its facility to meet the requirements of Subchapter E, Division 2 of this chapter on or before May 30, 2003, the compliance schedule is extended until six months after the issuance of the permit for operation of a low-NO_x burner and 12 months after issuance of the permit for operation of a secondary combustion system. Such application(s) must relate only to those modifications required to comply with Subchapter E, Division 2 of this chapter, and any issues incident thereto.

(c) The owner or operator of each portland cement kiln in Ellis County shall comply with the requirements of §117.3123 and §117.3142 of this title (relating to Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements; and Emission Testing and Monitoring for Eight-Hour Attainment Demonstration), and the applicable requirements of §117.3145 of this title (relating to Notification, Recordkeeping, and Reporting Requirements) that are associated with §117.3123 and §117.3142 of this title, as soon as practicable, but no later than March 1, 2009.

(1) The provisions regarding extension of compliance schedules in subsection (b) of this section do not apply to this subsection or the requirements of §117.3123, §117.3142, or the applicable requirements of §117.3145 of this title.

(2) If a contested case hearing is granted as a direct result of a permit application necessary to comply with the requirements of §117.3123 of this title, the compliance date of this subsection for the site affected by the contested case hearing is extended until no later than March 1, 2010. The compliance date for the affected site remains March 1, 2009, if:

(A) a contested case hearing is granted as a result of a permit application that includes modifications necessary to comply with §117.3123 of this title, but the contested case hearing is the result of modifications included in the permit that are unrelated to compliance with §117.3123 of this title, then the compliance date for the affected site remains March 1, 2009; or

(B) a contested case hearing is granted at the request of the owner or operator of the affected portland cement kiln or any third party affiliated with the owner or operator.

(d) The owner or operator of each portland cement kiln in Bexar County shall comply with the requirements of §117.3124 of this title (relating to Bexar County Control Requirements for Reasonably Available Control Technology (RACT)), and the applicable requirements of §117.3145 of this title (relating to Notification, Recordkeeping, and Reporting Requirements) as soon as practicable, but no later than January 1, 2025.

SUBCHAPTER H: ADMINISTRATIVE PROVISIONS

DIVISION 2: COMPLIANCE Flexibility

§117.9800

Statutory Authority

The amended rules are proposed under Texas Water Code (TWC), §5.102, concerning general powers; §5.103, concerning Rules; TWC, §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the TWC; TWC, §7.002, concerning Enforcement Authority, which authorizes the commission to enforce the provisions of the Water Code and the Health and Safety Code within the commission's jurisdiction; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purpose of the Texas Clean Air Act.

The amendments are also proposed under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; THSC, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC, §382.012, concerning the State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the proper control of the state's air; THSC, §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe reasonable requirements for measuring and monitoring the emissions of air contaminants; and THSC, §382.021, concerning Sampling Methods and Procedures.

The proposed amendments implement TWC, §§5.102, 5.103 and 7.002; and THSC, §§382.002, 382.011, 382.012, 382.016, 382.017, and 382.021.

§117.9800. Use of Emission Credits for Compliance.

(a) An owner or operator of a unit not subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) may meet emission control requirements of the sections specified in paragraphs (1) – (9) [(8)] of this subsection, in whole or in part, by obtaining an emission reduction credit (ERC), mobile emission reduction credit (MERC), discrete emission reduction credit (DERC), or mobile discrete emission reduction credit (MDERC) in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title (relating to Emission Credit Banking and Trading; and Discrete Emission Credit Banking and Trading), unless there are federal or state regulations or permits under the same commission account number that contain a condition or conditions precluding such use:

(1) §§117.105, 117.205, 117.405, [or] 117.1005, or 117.1105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT));

(2) §117.110 or §117.1010 of this title (relating to Emission Specifications for Attainment Demonstration);

(3) §117.1015 of this title (relating to Alternative System-Wide Emission Specifications);

(4) §117.115 of this title (relating to Alternative Plant-Wide Emission Specifications);

(5) §§117.123, 117.423, or 117.3120 of this title (relating to Source Cap);

(6) §§117.2010, 117.3010, or 117.3110 of this title (relating to Emission Specifications);

(7) §§117.410, 117.1310, 117.2110, or 117.3310 of this title (relating to Emission Specifications for Eight-Hour Attainment Demonstration); [or]

(8) §117.3123 of this title (relating to Dallas-Fort Worth Eight-Hour Ozone Attainment Demonstration Control Requirements)<u>; or </u>[.]

<u>(9) §117.3124 of this title (relating to Bexar County Control Requirements for Reasonably Available Control Technology (RACT)).</u>

(b) An owner or operator of a unit subject to §§117.320, <u>117.1120, </u>117.1020, 117.1220, or 117.3020 of this title (relating to System Cap) may meet the emission control requirements of these sections in whole or in part, by complying with the requirements of Chapter 101, Subchapter H, Division 1 or 4 of this title, by obtaining an ERC, MERC, DERC, or MDERC, unless there are federal or state regulations or permits under the same commission account number that contain a condition or conditions precluding such use.

(c) For the purposes of this section, the term "reduction credit (RC)" refers to an ERC, MERC, DERC, or MDERC, whichever is applicable.

(d) Any lower nitrogen oxides (NO_X) emission specification established under this chapter for the unit or units using RCs requires the user of the RCs to obtain additional RCs in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title and/or otherwise reduce emissions prior to the effective date of such rule change. For units using RCs in accordance with this section that are subject to new, more stringent rule limitations, the owner or operator using the RCs shall submit a revised final control plan to the executive director in accordance with §§117.156, 117.356, 117.456, 117.1056, 117.1256, and 117.1356 of this title (relating to Revision of Final Control Plan) and §117.252 and §117.1152 of this title (relating to Control Plan Procedures for Reasonably Available Control Technology (RACT)) to revise the basis for compliance with the emission specifications of this chapter. The owner or operator using the RCs 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. The owner or operator of the unit(s) currently using RCs shall calculate the necessary emission reductions per unit as follows.

Figure: 30 TAC §117.9800(d) (No change)