The Texas Natural Resource Conservation Commission (TNRCC or commission) adopts amendments to §117.10, concerning Definitions. The commission also adopts new §§117.131, 117.133, 117.134, 117.135, 117.138, 117.141, 117.143, 117.145, 117.147, and 117.149, concerning Utility Electric Generation in East and Central Texas; §§117.260, 117.261, 117.265, 117.273, 117.279, and 117.283, concerning Cement Kilns; §117.512, concerning Compliance Schedule for Utility Electric Generation in East and Central Texas; and §117.524, concerning Compliance Schedule for Cement Kilns. Sections 117.10, 117.131, 117.133, 117.135, 117.138, 117.141, 117.143, 117.145, 117.149, 117.260, 117.261, 117.265, 117.279, 117.283, 117.512, and 117.524 are adopted with changes to the proposed text as published in the December 31, 1999 and January 14, 2000 issues of the *Texas Register* (24 TexReg 11959 and 25 TexReg 308). Sections 117.134, 117.147, and 117.273 are adopted without changes and will not be republished.

The commission adopts these revisions to Chapter 117, concerning Control of Air Pollution from Nitrogen Compounds, and to the State Implementation Plan (SIP) in order to reduce nitrogen oxide (NO_x) emissions from cement kilns and electric utility power boilers and stationary gas turbines located in ozone attainment counties in east and central Texas. The 34 affected ozone attainment counties in which cement kilns or electric utility power boilers and stationary gas turbines are located are Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Comal, Ellis, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Hays, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, and Wharton Counties. Because of regional transport, the commission believes that this rulemaking will reduce ozone in ozone attainment areas, ozone near-nonattainment areas, and, in combination with other emission reduction rules, is a necessary and essential component of the one-hour attainment demonstration for ozone nonattainment areas.

In addition, the commission has renumbered the existing Division 2, concerning Commercial, Institutional, and Industrial Sources, as Division 3, and existing Subchapter D, concerning Administrative Provisions, as Subchapter E. Sections 117.131, 117.133 - 117.135, 117.138, 117.141, 117.143, 117.145, 117.147, and 117.149 were placed in a new Subchapter B, Division 2, concerning Utility Electric Generation in East and Central Texas, and §§117.260, 117.261, 117.265, 117.273, 117.279, and 117.283 were placed in a new Subchapter B, Division 4, concerning Cement Kilns. Sections 117.512 and 117.524 were placed in the renumbered Subchapter E, concerning Administrative Provisions. The renumbering of the existing Subchapter D as Subchapter E is necessary because the commission adopted a new Subchapter D in separate rulemaking published in this issue of the *Texas Register*.

The new sections are one element of the Dallas/Fort Worth (DFW) Attainment Demonstration SIP and were developed at the request of the North Texas Clean Air Steering Committee, which represents the DFW ozone nonattainment area. The purpose of these rules is to reduce NO_x emissions from cement kilns and electric utility power boilers and stationary gas turbines as part of the control strategy to reduce emissions of ozone precursors in order for the DFW ozone nonattainment area to be able to demonstrate attainment with the National Ambient Air Quality Standards (NAAQS) for ground-level ozone.

In addition, the revisions are one element of a new combined strategy to meet the NAAQS for ground-level ozone. The purpose of the strategy is to reduce overall background levels of ozone in order to assist in keeping ozone attainment areas and near-nonattainment areas in compliance with the federal ozone standards. The new strategy is also necessary to help the Beaumont/Port Arthur (BPA), DFW, and Houston/Galveston (HGA) ozone nonattainment areas as defined in 30 TAC §101.1, concerning Definitions, move closer to reaching attainment with the ozone NAAQS. The strategy takes into account recent science that shows that regional approaches may provide improved control of air pollution. In particular, staff has conducted photochemical grid modeling which indicates that 50% reductions in NO_x from elevated point sources in east and central Texas will reduce peak one-hour ozone between 14 and 27 parts per billion (ppb) at specific locations in the region, depending on the modeling day. The one-hour ozone benefits stretch across the east and central Texas counties and average six to seven ppb. Based on a one-hour exceedance design value of 128 ppb, the projected benefits of 50% point source NO_x reductions in the attainment counties of east and central Texas may be large enough to prevent some areas from being reclassified as not attaining the one-hour ozone NAAQS. It is the requirement under the Federal Clean Air Act (FCAA) Amendments of 1990 (42 United States Code (USC)) for meeting the one-hour standard that forms the basis for the regional NO_x control requirements. This rulemaking is based upon a body of evidence from aircraft measurements, seasonal modeling, back trajectories, and statistical studies indicating that electric generating facilities and cement kilns in central and eastern Texas contribute to the background levels of NO_x which impact the DFW area. Documents explaining these additional studies are included as appendices to the SIP. Additional details concerning the need for a regional strategy are as follows.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

The DFW ozone nonattainment area, an area defined by Collin, Dallas, Denton, and Tarrant Counties, was originally designated "moderate" under the FCAA Amendments of 1990 (42 USC) and thus was required to attain the one-hour NAAQS for ozone by November 15, 1996. As required by the FCAA, the state submitted an attainment demonstration plan in 1994 which projected attainment of the ozone NAAQS by 1996. This plan was based on a volatile organic compound (VOC) reduction strategy. DFW did not attain the ozone NAAQS in 1996. The United States Environmental Protection Agency (EPA) is authorized to redesignate an area to the next higher classification ("bump up") if the area fails to attain by the required date. In March 1998, in accordance with 42 USC, §7511(b)(2), the EPA reclassified the DFW area from moderate to serious, based on monitored exceedances of the ozone NAAQS between 1994 and 1996. The reclassification required the state to submit a revised SIP that demonstrates that the ozone NAAQS will be met in DFW by November 15, 1999. Because the DFW area continued to exceed the ozone NAAQS in 1999, the EPA may bump up the area to the severe classification. Regardless, the EPA and 42 USC, §7410 and §7502(a)(2), require the state to submit a revised SIP which demonstrates that the area will attain the ozone NAAQS as expeditiously as practicable. The rules adopted for DFW in this notice are one element of the ozone attainment demonstration SIP for DFW being adopted concurrently in this issue of the *Texas Register*. The commission plans to submit this SIP to the EPA in April, 2000.

In 1996, the commission began to develop new modeling for the DFW area and now is using newer air quality models with improved meteorological and emission inputs. The newer modeling since 1996 shows that reductions of NO_x in the DFW area and regionally will be necessary to attain the ozone

NAAQS. The current modeling also shows that achieving the ozone NAAQS in the DFW area will require strenuous effort because the area's rapid growth has resulted in increasing amounts of emissions due to increased levels of activity in the area. The emissions from increased activity are offsetting the emission reductions being achieved from new emission standards applicable to the on-road and non-road engine source categories which dominate the emissions inventory in the DFW area.

The emission reduction requirements adopted as part of this SIP package are the outcome of a development process which involved the EPA, the commission, local elected officials, citizens, industrial stakeholders, air quality researchers, and hired consultants. Local officials from the DFW area have formally submitted a resolution to the commission requesting the inclusion of many specific emission reduction strategies, including the one contained in these rules.

The NO_x reductions required for the area to attain the ozone NAAQS have been estimated by extensive use of sophisticated air quality grid modeling which, because of its scientific and statutory grounding, is the chief policy tool for designing emission reductions. Title 42 USC, §7511a(c)(2), requires the use of photochemical grid modeling for ozone nonattainment areas designated serious, severe, or extreme. The modeling has been conducted with input from a technical advisory committee. Hundreds of emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources and mobile sources were analyzed in at least fifty modeling iterations, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling submitted for public hearing and comment concurrently with these rules shows that, in order for DFW to achieve the ozone NAAQS by 2007, almost all of the practicably achievable NO_x reductions are necessary from each emission source category, including reductions from counties surrounding the DFW nonattainment area. Therefore, each strategy, including the reductions required by this rulemaking, is crucial to meet federal requirements for the DFW nonattainment area.

At the time the 1990 FCAA Amendments were enacted, the focus of controlling ozone pollution was on local controls. However, over the last ten years an increasing number of air quality professionals have concluded that ozone is a regional problem requiring regional strategies in addition to local control programs. As nonattainment areas across the United States prepared attainment demonstration SIPs in response to the 1990 FCAA Amendments, several areas found that modeling attainment was made much more difficult, if not impossible, because of high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport.

The commission has conducted air quality modeling and upper air monitoring with aircraft that found that regional air pollution from sources inside of Texas should be considered when studying air quality in Texas' ozone nonattainment areas. The Texas studies are corroborated by research studies of the Ozone Transport Assessment Group (OTAG), the most comprehensive attempt ever undertaken to understand and quantify the transport of ozone. The results of both the commission and OTAG studies point to the need to take a regional approach, as proposed in this rulemaking, to controlling air pollutants.

During the OTAG studies, the commission's modeling staff ran several sensitivity analyses for Texas using a regional modeling setup based on the Coastal Oxidant Assessment for Southeast Texas

(COAST) study. This analysis used the OTAG emission inventory, updated for Texas sources, to assess the impact of potential OTAG reductions on Texas. One modeling scenario, OTAG 5c, consisting of reductions across the domain (60% reduction of point source NO_x, 30% reduction of low-level NO_x, and 30% reduction of VOC), indicated that modeled reductions would reduce peak eight-hour ozone by as much as 20 ppb throughout most of the eastern half of Texas. Overall, the modeling indicated that a regional reduction strategy would benefit a wide area of the state.

During modeling for the HGA attainment demonstration SIP for the one-hour ozone standard, the commission's modeling staff conducted sensitivity analyses to determine the benefits that regional reductions might have on HGA, when applied simultaneously with local reductions. Unlike the commission's regional modeling exercises discussed in the previous paragraphs, these HGA model runs offer an opportunity to assess separately the benefits of reductions made within and outside a region. Model runs with and without the regional reduction scenarios in HGA were conducted. Modeling runs were completed to evaluate the ozone concentrations in the COAST modeling domain for September 8, 1993 with year 2007 projected emissions and assuming a 70% reduction of NO_x combined with a 15% reduction of VOC in the eight-county HGA area. Even with the large reductions in HGA, much of the upper Texas Coast had ozone concentrations that challenge the one-hour standard. The application of OTAG 5c reductions outside the HGA eight-county area showed that the reductions are clearly beneficial to HGA, with additional ozone benefits of between five and ten ppb.

Additional modeling has been completed by commission staff assessing the potential benefits of regional NO_x reductions in the attainment counties of east and central Texas. This modeling indicates that controls which reduce all elevated point source NO_x emissions by 50% in the region will reduce peak one-hour ozone between 14 and 27 ppb at specific locations in the region, depending on the modeling day. The one-hour ozone benefits stretch across the east and central Texas counties and average six to seven ppb. Based on a one-hour exceedance design value of 128 ppb, the projected benefits of 50% point source NO_x reductions in the attainment counties of east and central Texas may be large enough to prevent some areas from being reclassified as not attaining the one-hour ozone NAAQS.

Modeling tests indicate that point source NO_x reductions of less than 50% have limited ozone reduction benefit, whereas reductions at and above 50% show increasing ozone reduction benefits. For example, in the DFW area, 25% NO_x reductions in all attainment counties of east and central Texas result in a seven to ten ppb one-hour ozone reduction, whereas 50% NO_x reductions over the same area result in a 21-27 ppb one-hour ozone reduction. Doubling the NO_x reduction from 25% to 50% provides more than twice the ozone reduction benefit. However, this test also includes reductions made in the DFW area. The benefit attributable to the regional reduction is about four to five ppb. It is clear that NO_x reductions in just the attainment counties of east and central Texas are not sufficient for DFW to attain the one-hour ozone NAAQS. Substantial reductions will still be needed within the DFW four-county nonattainment area and the surrounding eight consolidated metropolitan statistical area (CMSA) counties.

The commission's air quality modeling studies conducted for the DFW area show that attaining the one-hour ozone NAAQS will be difficult, and that NO_x reductions from all modeled source categories that impact DFW's air quality will be required. Therefore, reductions of 50% NO_x in the attainment counties of east and central Texas are a necessary component for the DFW area to attain the one-hour ozone NAAQS. Consequently, these Chapter 117 rules are a necessary component of the DFW and regional NO_x reduction strategy.

The increasing benefit of 50% NO_x reductions is also seen in other areas of east and central Texas. In evaluating eight-hour modeling data for six episode days in the Tyler-Longview area, a 25% decline in NO_x provides an average reduction in peak eight-hour ozone of 12 ppb, whereas a 50% decline in NO_x provides an average reduction of 29 ppb. Similarly in Austin, a 25% NO_x reduction provides an average ozone benefit of six ppb, whereas a 50% reduction provides an average ozone benefit of 15 ppb. Tyler-Longview and Austin air quality monitoring data have had values in excess of the eight-hour NAAQS. The reductions in the eight-hour ozone average will be very helpful to these areas.

The commission is developing a regional strategy to reduce most categories of man-made NO_x emissions by approximately 50% in the attainment counties of east and central Texas. Emissions of NO_x come mainly from the combustion of fossil fuels, particularly motor vehicles and electric power plants. In recent years, the power plants in the attainment counties in east and central Texas accounted for nearly as much NO_x as all motor vehicles used on all roads in the region. However, recently adopted regulations requiring cleaner fuels and vehicles are projected to reduce vehicular NO_x emissions in the attainment counties in east and central Texas by 2007 to an amount approaching half of the 1996 emissions. In contrast, new regulations would be necessary in order to cut the NO_x emissions from power plants and other point sources in the region approximately in half by 2007.

Under the new emission reduction mandates contained in Senate Bill (SB) 7, 76th Legislature, 1999, the 1997 NO_x emissions of approximately 270 tons per ozone day (tpd) (daily emissions June-August) from the grandfathered electric generating facilities (EGFs) in the attainment counties of east and central Texas could be expected to decline by about 50%. However, when the SB 7 reduction requirement is expressed as a percentage reduction of the NO_x from all EGFs in the attainment counties of east and central Texas, including permitted facilities, the 50% reduction amounts to only an 18% reduction, since 480 tpd of the total EGF emissions of 750 tpd of NO_x in 1997 came from permitted facilities. In combination with the SB 7 reductions in Chapters 101, concerning General Air Quality Rules, and 116, concerning Control of Air Pollution by Permits for New Construction or Modification (see the January 7, 2000 issue of the *Texas Register* (25 TexReg 128)), these Chapter 117 rules would reduce 1997 EGF NO_x emissions in the attainment counties of east and central Texas by about 50%, cement kiln NO_x emissions in these counties by about 27%, and total point source NO_x emissions in these counties by about 35%. Therefore, these Chapter 117 rules are a necessary component of the regional NO_x reduction strategy. As noted earlier, a 50% NO_x reduction was the goal, but in some cases technology is not available which would achieve a 50% or higher NO_x reduction. Specifically, for wet process cement kilns, selective noncatalytic reduction (SNCR) reportedly has difficulties involved in continuous injection of the reducing agents. While SNCR is apparently not applicable to wet process cement kilns, it does appear to be a promising technology for dry process cement kilns. The other post-combustion control available, selective catalytic reduction (SCR), has been tested previously on cement kilns. The application of SCR at cement kilns was found to be problematic due to the high concentrations of particulate matter in the exhaust gas stream. This leads to catalyst fouling, causing high pressure drops and reduced catalyst activity. A 30% NO_x reduction was established as the goal for cement kilns since this is a level which the commission expects can be achieved through combustion modifications.

PUBLIC UTILITY REGULATORY ACT DETERMINATION

As described earlier in this preamble, the commission adopts these revisions to Chapter 117 and the SIP in order to reduce NO_x emissions in ozone attainment counties in east and central Texas. Because of regional transport, the commission believes that this rulemaking will reduce ozone in ozone attainment areas, ozone near-nonattainment areas, and, in combination with other emission reduction rules, is a necessary and essential component of the one-hour attainment demonstration for ozone nonattainment areas. Accordingly, the commission makes the following determination, as required by the Public Utility Regulatory Act (PURA), Texas Utilities Code (TUC), §39.263(c)(1)(A) and §39.263(c)(3): reductions of NO_x made in compliance with this rulemaking are hereby determined to be an essential component in achieving compliance with the NAAQS for ground-level ozone; and the amount and location of reductions of NO_x emissions resulting from this rulemaking are hereby determined to be consistent with the air quality goals and policies of the commission.

SECTION BY SECTION DISCUSSION

The changes to §117.10 add definitions of "continuous emission monitoring system (CEMS)," "large DFW system," "small DFW system," "predictive emissions monitoring system (PEMS)," and "twenty-four hour rolling average." The terms "CEMS" and "PEMS" are used in multiple sections of Chapter 117 but are not currently defined. The new definitions of CEMS and PEMS will clarify these terms. The terms "large DFW system" and "small DFW system" are being added as new §117.10(18) and (36), respectively, in response to comments on the proposed 30 TAC Chapter 117 rules identified as Rule Log No. 1999-056-117-AI (24 TexReg 11977, December 31, 1999). The reasoning for the suggested definitions are found in the preamble for the final 30 TAC Chapter 117 rules identified as Rule Log No. 1999-056-117-AI which is published elsewhere in this issue of the *Texas Register*. The definition of “twenty-four hour rolling average” was developed in response to a request for clarification from electric utilities and is consistent in form with the recently adopted definition of "thirty-day rolling average.” (See the November 12, 1999 issue of the *Texas Register* (24 TexReg 10113).) In addition, the changes to §117.10 revise the definition of "electric power generating system" by replacing the use of this term within the definition with a reference to generation of electricity for compensation; and clarify that the rules continue to apply if the electric power generating system is sold to an entity which otherwise would not be subject to the rules. The changes to the definition of "electric power generating system" further revise the definition to include boilers, steam generators, auxiliary steam boilers, and stationary gas turbines 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 the listed 31 attainment counties of east and central Texas in which EGFs are located. The changes to §117.10 also revise the definition of "major source" by adding the major source definition contained in the Prevention of Significant Deterioration of Air Quality regulations applicable in the listed 34 attainment counties of east and central Texas in which EGFs or cement kilns are located. This revision would prevent confusion caused by the title under which these Chapter 117, Subchapter B rules were proposed: “Combustion at Existing Major Sources.” In addition, the changes to §117.10 clarify the intent of the definition of "nitric acid production unit" by replacing a reference to "facility" with the term "source" and clarify the intent of the definition of "parts per million by volume (ppmv)" by replacing the reference to "rule" with a reference to the more descriptive term "chapter." The changes to §117.10 also clarify the intent of the definitions of "stationary gas turbine" and "stationary internal combustion engine" by replacing the reference to "facility" with a reference to "major source," and revise the definition of "stationary internal combustion engine" by incorporating language from 40 Code of Federal Regulations (CFR) Part 89 (Control of Emissions from New and In-Use Nonroad Engines), §89.2 (Definitions), to clarify the distinction between stationary and mobile nonroad engines. In addition, the changes to §117.10 revise the definition of "unit" by deleting language regarding the date a unit was placed into service. The language being deleted is unnecessary because it duplicates language contained in §§117.103(a)(1), 117.105(k)(2), 117.203(1), and 117.205(a)(3). Finally, the changes to §117.10 would update the reference to Chapter 101 to reflect the new title of this chapter adopted by the commission on December 1, 1999. (See the December 17, 1999 issue of the *Texas Register* (24 TexReg 11494).)

The new §117.131, concerning Applicability, identifies the sources affected by the requirements. This rule applies to boilers and stationary gas turbines used to generate electric power which were placed into service before December 31, 1995. The rule would not apply to auxiliary boilers which are sometimes present at power plants. Auxiliary boilers are much smaller than power boilers, operate rarely, and account for only 0.01% of the power plant emissions in the attainment counties of east and central Texas. Requiring these small boilers to meet the emission specifications would not be cost-effective, considering the emission control, monitoring, and administrative costs and the negligible emission reductions that would result. The applicability of this division is limited to the major electricity producers: electric cooperatives, independent power producers, municipalities, river authorities or public (investor owned) utilities in the specified counties. Electricity production is either the principal product, or one of the principal products of these entities. Not included are owners or operators of commercial, institutional, and industrial sources that sell less than one-third of their potential electrical output capacity to the electric grid for compensation. Among these non-utility sources are some of the gas turbine cogeneration facilities located at certain chemical plants and refineries in the affected counties. Examples of other, smaller sources outside the scope of the revised rule include a sawmill which could use a boiler to cogenerate steam and electricity, and smaller entities, such as a recreational vehicle park owner or operator who provides electricity for park residents. Emissions related to electric generation from such commercial, institutional, and industrial sources are small, and the resulting reductions from these smaller sources would not be cost-effective. The commission will evaluate the need for reductions from these exempt non-utility sources separately from this rulemaking.

Section 117.131 as adopted does not include units which were placed into service after December 31, 1995. Inclusion of new units is not necessary because the best available control technology (BACT) requirements of the commission's new source review permitting program will ensure that NO_x emissions are adequately controlled at units placed into service after that date. Therefore, it is unnecessary to include counties other than the 31 listed counties.

The new §117.133, concerning Exemptions, identifies emission units which would not be subject to the new emission specification. This division does not apply to utility electric power boilers or stationary gas turbines if the annual heat input does not exceed 2.2 (10^{11}) British thermal units (Btu) per year, averaged over three years. If operated at 2.2 (10^{11}) Btu per year or less, potential emissions are less than 30 tons per year of NO_x from any of the affected permitted gas-fired power boilers or turbines. Similarly, this division does not apply to stationary gas turbines and auxiliary boilers which are used solely to power other units during start-ups; units which operate no more than an average of 10% of the hours of the year, averaged over the three most recent calendar years, and no more than 20% of the hours in a single calendar year; and cogeneration units that, averaged over the three most recent calendar years, sold less than one-third of its potential electrical output capacity to a utility power distribution system. Requiring such small emission sources to meet the emission specifications would not be cost-effective, considering the emission control, monitoring, and administrative costs and the negligible emission reductions that would result.

The new §117.134, concerning Gas-Fired Steam Generation, relocates existing NO_x emission specifications for electric utility boilers in certain ozone attainment counties from §117.601, concerning Gas-Fired Steam Generation. In addition to the 12 DFW and HGA ozone nonattainment counties, the minimal NO_x standards of §117.601 have been applicable in 19 counties comprising the attainment counties of the Houston and Dallas/Fort Worth Air Quality Control Regions since 1972. The change brings the Chapter 117 utility boiler NO_x limits affecting ozone attainment counties into consecutive sections of a common rule division. Counties listed in §117.601 which do not contain boilers above the applicability threshold of 600,000 pounds per hour maximum steam generation capacity have been removed. Maintaining rule applicability in these counties for future units is unnecessary, because any new gas-fired boilers would be subject to much lower BACT emission limitations of the commission's NSRP program. In separate rulemaking which is published elsewhere in this issue of the *Texas*

Register, the commission is repealing §117.601 because the §117.601 requirements for the affected counties in ozone nonattainment areas are being relocated to the rule division for electric utility generation in ozone nonattainment areas.

The new §117.135, concerning Emission Specifications, sets the NO_x emission limit at 0.165 pound (lb) of NO_x per million Btu (MMBtu) for coal or lignite-fired electric power boilers. Many permitted EGFs are currently authorized to operate at an emission rate in excess of 0.165 lb/MMBtu. Specifically, current average emission rates for permitted EGFs in attainment counties in East Texas are approximately 0.33 lb NO_x/MMBtu. A reduction to 0.165 lb NO_x/MMBtu would accomplish the goal of a 50% reduction necessary to achieve regional reductions in ambient ozone. For gas-fired electric power boilers, the NO_x emission limit is at 0.14 lb NO_x/MMBtu, while for stationary gas turbines, the NO_x emission limit is at 0.15 lb NO_x/MMBtu (or alternatively, 42 ppmv NO_x, adjusted to 15% oxygen), except those subject to SB 7 which are limited to 0.14 lb NO_x/MMBtu.

The new §117.138, concerning System Cap, creates a flexible alternative to direct compliance with the NO_x emission specifications in §117.135. This section is patterned on the existing source cap compliance option in §117.223, for industrial, commercial and institutional combustion sources. The system cap sets limits on total pounds of NO_x allowed to be emitted by an electric utility system. A cap has the advantage over rate-based standards of allowing the source owner to control the activity levels of the regulated equipment as a means of compliance. This means that a company can comply by installing less extensive emission controls and choosing to operate the regulated equipment less, or by upgrading equipment to require less fuel combustion.

The averaging period for the NO_x system cap is an annual average, consistent with the emission specifications of §117.135, which are on the basis of an annual (calendar year) average. The baseline period for H_i, the historical heat input used in the annual average of §117.138(c)(1), is 1996, 1997, and 1998. This three-year period is consistent with the commission staff's modeling period. Fluctuations in ambient temperature patterns often cause significant annual variation in electric demand. An average over three years limits the influence of one particular year on the design value.

Section 117.138 does not require the inclusion of new electric generating units in the system cap. Inclusion of new units is not necessary because the BACT requirements of new source review permitting will ensure that NO_x emissions are adequately controlled at new units.

The new §117.141, concerning Initial Demonstration of Compliance, establish the criteria for an initial demonstration of compliance at utility electric power boilers and stationary gas turbines, including testing, and installation and verification of operational status of CEMS and PEMS before the testing. The requirements are parallel to existing requirements in §117.111 and §117.211, concerning Initial Demonstration of Compliance.

The new §117.143, concerning Continuous Demonstration of Compliance, requires installation of CEMS or PEMS, or less stringent monitoring requirements in some cases. Many of the electric utility boilers in the 31 affected attainment counties are currently monitoring NO_x continuously under the federal acid rain rules of 40 CFR 75; some of the smaller units not subject to the federal acid rain rules of 40 CFR 75 are required to monitor NO_x under existing new source review permitting requirements.

For peaking plants, the owner or operator may choose to comply with the less stringent requirements of 40 CFR Part 75, Appendix E, §1.1 or §1.2, and calculate NO_x emission rates based on those procedures, rather than install CEMS or PEMS. Similarly, for auxiliary boilers, the owner or operator may choose to comply with the appropriate (considering boiler maximum rated capacity and annual heat input) industrial boiler monitoring requirements of §117.213, concerning Continuous Demonstration of Compliance, in lieu of installing CEMS or PEMS. The relatively limited situations in which additional costs for new NO_x monitors would be necessary is expected to make the system cap an attractive option for electric utilities. The requirements are parallel to existing requirements in §117.113 and §117.213, concerning Continuous Demonstration of Compliance.

The new §117.145, concerning Final Control Plan Procedures, specifies certain information requirements for showing compliance with the emission specifications of §117.135 or the system cap of §117.138, to be included in a report submitted to the executive director. The requirements are parallel to existing requirements in §117.115 and §117.215, concerning Final Control Plan Procedures.

The new §117.147, concerning Revision of Final Control Plan, allows the owner or operator to submit a revised final control plan, provided that the revised plan continues to demonstrate compliance with the appropriate emission limits and the final compliance dates.

The new §117.149, concerning Notification, Recordkeeping, and Reporting Requirements, specify the required start-up and shutdown records, notification, reporting of test results, annual reports, and recordkeeping for electric power boilers and stationary gas turbines. The requirements are parallel to existing requirements in §117.119 and §117.219, concerning Notification, Recordkeeping, and Reporting Requirements.

The new §117.260, concerning Cement Kiln Definitions, adds definitions of clinker, long dry kiln, long wet kiln, portland cement, portland cement kiln, precalciner kiln, and preheater kiln.

The new §117.261, concerning Applicability, specifies the five counties (Bexar, Comal, Ellis, Hays, and McLennan) in which the new portland cement kiln requirements apply. These are the counties in east and central Texas in which existing portland cement kilns are located. Inclusion of new cement kilns is not necessary because the BACT requirements of new source review permitting will ensure that NO_x emissions are adequately controlled at new kilns. Therefore, it is unnecessary to include counties other than the five listed counties.

The new §117.265, concerning Emission Specifications, establishes emission limits on the basis of pounds of NO_x per ton of clinker produced. These emission limits are based on the NO_x emissions for a 30-day rolling average, and vary depending on the type of cement kiln (long wet; long dry; preheater; preheater-precalciner; or precalciner). The emission limits are based on those described in the EPA's notice of proposed rulemaking concerning *Federal Implementation Plans to Reduce the Regional Transport of Ozone* which was published in the October 21, 1998 issue of the *Federal Register* (63 FR 56394). The EPA stated that these limits represent an average 30% decrease in NO_x emissions from uncontrolled levels. In order to ensure emission reductions of approximately 30% from the 1996 emissions inventory in Ellis County, the commission has established a more stringent limit for wet process cement kilns in this county. To provide additional flexibility in all affected counties yet still ensure that all reasonable emission reduction measures have been implemented, the commission has added an option which provides that each kiln equipped with low-NO_x burners and mid-kiln firing is not required to meet the NO_x emission limits.

The new §117.273, concerning Continuous Demonstration of Compliance, requires the installation, calibration, maintenance, and operation of a CEMS or PEMS to monitor kiln exhaust NO_x. Either a CEMS or PEMS is necessary in order to determine continuous compliance with the emission limits.

The new §117.279, concerning Notification, Recordkeeping, and Reporting, requires notification concerning CEMS or PEMS performance evaluation and submission of any CEMS or PEMS relative accuracy test audit. The new §115.279 also requires monitoring records of daily NO_x emissions, daily production of clinker, average NO_x emission rate (30-day rolling average), stack sampling results, and the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS and PEMS.

The new §117.283, concerning Source Cap, provides an alternative to complying with the NO_x emission limits of §117.265. Specifically, §117.283 allows an owner or operator to choose to reduce total NO_x emissions (in pounds per day (ppd)) from all cement kilns at the account to at least 30% less than the total NO_x emissions (in ppd) from all cement kilns in the account's 1996 emissions inventory. At cement plants with multiple kilns, this will allow NO_x emission reductions to be achieved at these kilns in whatever manner the owner or operator considers to be the most cost-effective and technically feasible. Any cement kilns placed into service on or after December 31, 1999 are included in order to allow a new cement kiln's lower NO_x emission rate to be credited toward the NO_x emission reductions needed by older cement kilns at the same account while still achieving the goal of an overall reduction in NO_x emissions.

The new §117.512, concerning Compliance Schedule for Utility Electric Generation in East and Central Texas, sets a compliance date of May 1, 2003 for units owned by utilities which are subject to the cost-recovery provisions of TUC, §39.263(b), and May 1, 2005 for all other units. This date allows approximately three years to achieve emission compliance for units owned by utilities which are subject to the cost-recovery provisions of TUC, §39.263(b). A two-year implementation schedule has been considered necessary but achievable for other emission reduction requirements in Chapter 117. The FCAA requires states to develop SIPs that will result in attainment as expeditiously as practicable, and compliance with regional NO_x reduction rules by May 1, 2003, has been considered by the EPA to be necessary for such expeditious attainment of the ozone NAAQS. For EGFs, an additional year for compliance appears necessary to allow adequate time for design engineering, equipment procurement, and installation. The commission expects that most projects necessary to meet the new Chapter 117 requirements for EGFs will be able to qualify for the standard permit available under 30 TAC Chapter 116, §116.617 (Standard Permit for Pollution Control Projects). An additional two years is being provided for units owned by utilities which are not subject to the cost-recovery provisions of TUC, §39.263(b), in order to address concerns about the availability of engineering, fabrication, and installation contractors.

The new §117.524, concerning Compliance Schedule for Cement Kilns, establishes a compliance date of May 1, 2003 for cement kilns in Ellis County, and May 1, 2005 for cement kilns in Bexar, Comal, Hays, and McLennan Counties. This date allows approximately three years for Ellis County cement kilns to achieve emission compliance. A two-year implementation schedule has been considered necessary but achievable for other emission reduction requirements in Chapter 117. Because of the unique nature of cement kilns, the commission believes it is appropriate to allow approximately three years for design engineering, equipment procurement, and installation. The commission expects that most projects necessary to meet the new Chapter 117 requirements for cement kilns will be able to qualify for the standard permit available under 30 TAC Chapter 116, §116.617 (Standard Permit for Pollution Control Projects). An additional two years is being provided for cement kilns in Bexar, Comal, Hays, and McLennan Counties in order to address concerns about the availability of engineering, fabrication, and installation contractors.

The commission requested comments on what, if any, emission banking and trading program should be developed to offer alternative means of compliance for facilities required to make NO_x reductions for SIP purposes. The commission is exploring the possibility of either the creation of a mass cap and trade system or revising the existing emission banking and trading system in Chapter 101, General Air Quality Rules, §101.29, concerning Emissions Banking and Trading. The commission intends to propose a comprehensive trading system during summer 2000. The commission believes it is appropriate to develop a holistic approach to emission trading, as opposed to a piecemeal approach. As noted in the rule proposal preamble, the commission is open to accepting all ideas regarding an emission trading program. Comments on emission trading will not be addressed as part of this rulemaking, but will be addressed when the commission considers its banking and trading program during summer 2000.

A mass cap and trade system would require that the commission allocate allowances to participating facilities. Each allowance would be an authorization to emit a specific amount of NO_x, for example 100 tons. Each participating facility would be required to have allowances equal to or greater than its emissions during a specific control period. The control period could be identified as an ozone season, a 12-month period, or some other appropriate period. Allowances could be traded from one facility to another so a facility that reduced emissions below its allotted allowances could sell excess allowances to another facility or a broker. Additionally, a facility that finds required reductions to be cost-prohibitive can purchase equivalent credits to meet its burden of compliance. This option would require monitoring and reporting on a regular basis to assure that compliance with the allowances is met. This system would put a cap on all emissions from participating facilities. Participation in this type of system is usually mandatory to insure that participating facilities must comply with equivalent emission requirements. An allowance trading system could be similar to the Emissions Banking and Trading of Allowances System adopted on December 16, 1999 under Subchapter H of Chapter 101, implementing the allowance trading requirements of SB 7. (See the January 7, 2000 issue of the *Texas Register* (25 TexReg 128).)

The existing emission reduction credit (ERC) and discrete ERC (DERC) trading systems are based on the concepts of open market systems. Participation is not mandatory; facilities have the option of either complying with the emission standard or using emission credits to offset the emission standard. Those sources choosing to participate in the open market system would quantify their reductions from a set baseline. These reductions could then be purchased and used by other sources to satisfy their NO_x reduction obligation.

If a mass cap and trade system were proposed, the commission requested comment on the following issues: trading restrictions; expiration of allowances; addition of new sources into the system; initial allotment of allowances; and relationship to federal new source review permitting (prevention of significant deterioration (PSD) and nonattainment).

If the existing trading program is relied on to provide flexibility, the commission requested comments on what changes need to be made to address the following issues: insuring that banked emissions are not also used towards any SIP demonstration (double counting); usability of the trading system; and baseline.

The commission requested comments on these issues and any other issues that might be relevant to the development of an emission banking and trading program. Since the commission is not proposing a program at this time, this rule adoption preamble does not include an analysis of the comments on this issue. The purpose of soliciting these comments is to assist the commission in the development of an emission banking and trading program. The commission held stakeholder meetings to discuss the comments received and solicit input before formally proposing an emissions banking and trading program, estimated to occur sometime during summer 2000.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMITS PROGRAM

Since 30 TAC Chapter 117 is an applicable requirement under 30 TAC Chapter 122, owners or operators subject to the Federal Operating Permit Program must, consistent with the revision process in Chapter 122, revise their operating permit to include the revised Chapter 117 requirements for each emission unit affected by the revisions to Chapter 117 at their site.

FINAL REGULATORY IMPACT ANALYSIS

The commission has reviewed the rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and has determined that the rulemaking meets the definition of a "major environmental rule" as defined in that statute. "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. The amendments to Chapter 117 will require emission reductions from cement kilns and utility electric boilers and stationary gas turbines in attainment counties in east and central Texas. The rules are intended to protect the environment and may have adverse effects on certain EGFs and cement kilns which could be considered a sector of the economy.

Although the amendments meet the definition of a "major environmental rule" as defined in the Texas Government Code, they do not meet any of the four applicability requirements listed in §2001.0225(a). Specifically, the emission limitations and control requirements within this rulemaking were developed in order to meet the NAAQS for ozone set by EPA under FCAA, §109, and therefore meet a federal requirement. States are primarily responsible for ensuring attainment and maintenance of the NAAQS once EPA has established them. Under FCAA, §110 and related provisions, states must submit, for approval by EPA, SIPs that provide for the attainment and maintenance of NAAQS through control programs directed to sources of the pollutants involved. The commission has performed photochemical grid modeling which predicts that the controls required by these rules will result in reductions in ozone formation in one or more nonattainment areas in Texas. This rulemaking is not an express requirement of state law, but was developed specifically in order to meet the air quality standards established under federal law as NAAQS. Specifically, this rulemaking is intended to help bring ozone nonattainment areas into compliance, and to help keep attainment and near-nonattainment areas from going into nonattainment. The rulemaking does not exceed a standard set by federal law, exceed an express requirement of state law (unless specifically required by federal law), or exceed a requirement of a delegation agreement. The rulemaking was not developed solely under the general powers of the agency, but was specifically developed to meet the air quality standards established under federal law as the NAAQS and authorized under Texas Clean Air Act (TCAA), §§382.011, 382.012, and 382.017. Comments received during the comment period regarding the draft regulatory impact analysis (RIA) are addressed in the SECTION BY SECTION ANALYSIS section of this preamble.

TAKINGS IMPACT ASSESSMENT

The commission has completed a takings impact assessment for this rulemaking. The following is a summary of that assessment. The rules requires NO_x emission reductions from cement kilns located in Bexar, Comal, Ellis, Hays, and McLennan Counties. The rules also require NO_x emission reductions from utility electric power boilers and stationary gas turbines that generate electric energy for compensation owned or operated by an electric cooperative, independent power producer, municipality, river authority, or public utility 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.

The rules are one element of the DFW Attainment SIP as well as part of a new strategy to meet the NAAQS for ground-level ozone. The strategy is necessary to reduce overall background levels of ozone in order to assist in keeping ozone attainment areas and near-nonattainment areas in compliance with federal ozone standards. The strategy and the modeling supporting it are discussed in other sections of this preamble. Promulgation and enforcement of the rule amendments may possibly burden private real property because the permanent installation of new equipment, such as low-NO_x burners or post-combustion controls, may be necessary to comply with the new requirements. Although the rules do not directly prevent a nuisance or prevent an immediate threat to life or property, they do prevent a real and substantial threat to public health and safety and fulfill a federal mandate under §110 of the 1990 Amendments to the FCAA. Specifically, the emission limitations and control requirements within this rulemaking were developed in order to meet the NAAQS for ozone set by the EPA under §109 of the FCAA. States are primarily responsible for ensuring attainment and maintenance of NAAQS once the EPA has established them. Under §110 of the FCAA and related provisions, states must submit, for approval by the EPA, SIPs that provide for the attainment and maintenance of NAAQS through control programs directed to sources of the pollutants involved. Therefore, the purpose of this rulemaking is to meet the air quality standards established under federal law as NAAQS. Consequently, the following exemption applies to these rules: an action reasonably taken to fulfill an obligation mandated by federal law.

COASTAL MANAGEMENT PROGRAM CONSISTENCY REVIEW

The commission has determined that this rulemaking relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et seq.), and the commission's rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with Texas Coastal Management Program. As required by 31 TAC §505.11(b)(2) and 30 TAC §281.45(a)(3), relating to actions and rules subject to the CMP, commission rules governing air pollutant emissions must be consistent with the applicable goals and policies of the CMP. The commission has reviewed this action for consistency with the CMP goals and policies in accordance with the regulations of the Coastal Coordination Council. For this rulemaking, the commission has determined that the rules 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(q), which requires that the commission protect air quality in coastal areas. This rulemaking is intended to reduce overall emissions of NO_x from cement kilns and electric utility boilers and stationary gas turbines. This action is consistent with the CMP because it does not authorize any new emissions and will reduce existing emissions of NO_x. No comments were received during the comment period regarding the consistency of the rulemaking with the CMP goals and policies.

HEARING AND COMMENTERS

Public hearings on this proposal were held on January 24, 2000 in El Paso; on January 25, 2000 in Austin; on January 26, 2000 in Longview and Irving; on January 27, 2000 in Dallas and Lewisville; on January 28 in Fort Worth; on January 31, 2000 in Beaumont and Houston; and on February 9, 2000 in Denton. The comment period was originally scheduled to close on February 1, 2000, but was extended until 5:00 p.m. on February 14, 2000. (See the January 21, 2000 issue of the *Texas Register* (25 TexReg 461).)

Sixty-two commenters submitted oral testimony on this proposal. Six hundred twenty commenters submitted written testimony on the proposal. Alamo Cement Company (Alamo); Capitol Cement, a division of Capitol Aggregates, Ltd (Capitol); Cemex USA (Cemex); Texas Industries, Inc. (TXI); Texas-Lehigh Cement Company; and North Texas Cement Company (North Texas) submitted joint comments as TNACC. The Sierra Club - Dallas Regional Group; Greater Fort Worth Sierra Club (GFWSC); Downwinders At Risk (DAR); Sustainable Economic and Environmental Development (SEED); Texas Campaign for the Environment; Texas Clean Water Action (TWCA); and Texas Public Citizen (TPC) submitted joint comments and will be referred to as Dallas Sierra Club. The City of Denton and the City of Garland submitted joint comments and will be referred to as Denton/Garland. The Senior Citizens Alliance of Tarrant County (SCATC) and the Senior Political Action Committee (SPAC) submitted joint comments and will be referred to as SCATC/SPAC. The Texas Public Power Association (TPPA) and Environmental Defense (ED) submitted joint comments and will be referred to as TPPA/ED.

Nine individuals supported the proposed revisions, while three individuals opposed the proposed revisions. Alamo; American Lung Association of Texas (ALAT); City of Austin d/b/a Austin Energy (Austin); DeSoto City Council Member James Billion (Billion); Brazos Electric Power Cooperative (Brazos); Bryan Texas Utilities (Bryan); Capitol; Cemex; the Center for Energy and Economic Development (CEED); Central and South West Services, Inc. (CSW); Citizens for a Safe Environment (CSE); City Public Service of San Antonio (CPS); Clean Air Action Corporation (CAAC); the City of Cleburne (Cleburne); City of Dallas (Dallas); Dallas Sierra Club; DAR; Denton City Council Member Mark Burroughs (Burroughs); Denton/Garland; Dow Chemical Company (Dow); Duncanville City Council Member Judy Richards (Richards); the Ellis County Cement Industry (ECCI); ED; Engine Manufacturers Association (EMA); EPA; Fort Worth Chamber of Commerce (FWCC); State Representative Toby Goodman (Goodman); GFWSC; Green Party of Tarrant County (GPTC); Cedar Hill City Council Member Amanda Hall (Hall); Holnam Texas Limited Partnership (Holnam); League of Women Voters of Dallas (LWVD); League of Women Voters of Tarrant County (LWVTC); League of Women Voters of Texas (LWVTX); Lower Colorado River Authority (LCRA); State Representative Tommy Merritt (Representative Merritt); Neighbors for Neighbors (NFN); North American Coal Corporation (NACC); Ontario Power Generation (OPG); Reliant Energy (Reliant); Sabine Mining Company (Sabine); San Miguel Electric Cooperative, Inc. (San Miguel); Sierra Club - Lone Star Chapter (SCLSC); North Texas Clean Air Steering Committee (Steering Committee); Tarrant Coalition for Environmental Awareness (TCEA); Tenaska III Texas Partners (Tenaska); Texas Chemical Council (TCC); Texas Mining and Reclamation Association (TMRA); Texas Municipal Power Agency (TMPA); NAACP - Texas State Conference (NAACP); TNACC; TPC; TPPA/ED; Turner, Mason, and Company (Turner); TWCA; TXU Electric Company (TXU); City of Tulsa (Tulsa); City of Tyler

(Tyler); and 594 individuals generally supported the proposed revisions but suggested changes or clarifications. Cemex and Capitol supported the comments submitted by TNACC. Brazos and CPS supported the comments submitted by TPPA/ED. Dallas Sierra Club's comments included the *Citizen's Implementation Plan for Cleaner Air in DFW* (January 2000). ALAT, CSE, LWVD, SCLSC, and 184 individuals expressed support for this plan.

ANALYSIS OF TESTIMONY

CEED, CPS, CSW, Holnam, NACC, Sabine, TMRA, TNACC, and TXU commented on the draft RIA. CEED, CPS, Holnam, NACC, TNACC, and TXU stated that the proposed rules were not evaluated in accordance with the analysis requirements for a major environmental rule. CEED, CPS, CSW, Holnam, NACC, Sabine, TMRA, TNACC, and TXU stated that the commission should perform a regulatory analysis and prepare a detailed economic analysis as required by Texas Government Code, §2001.0225. TNACC commented that *The Senate Natural Resources Committee, Interim Report to the 75th Legislature, Use of Cost Benefit Analysis in Environmental Regulation* (September 1996) regarding §2001.0225 states on page 8 that "[t]he heightened scrutiny approach would be applied only to the environmental regulations that are *not specifically required* by federal law, a federally-delegated program agreement or an express requirement of state law. Obviously, if the agency has *no discretion about whether to adopt regulations*, it should not be required to prepare a heightened scrutiny document." (TNACC's emphasis added) TXU urged the commission to perform a cost-benefit analysis with reductions at different intervals between 25% and 50% for electric utilities. TXU stated that Texas Government Code, §2001.0224(5), also requires a cost-benefit note and commented that

Texas Health and Safety Code, TCAA, §382.011 and §382.024, require the commission to take into account the economic feasibility and reasonableness.

While CEED, CSW, Holnam, NACC, and TXU agreed that the proposed NO_x limits are not specifically required by state law, CEED, CPS, CSW, Holnam, NACC, and TNACC asserted that the proposed rules are not specifically required by federal law because the FCAA does not set out specific rules that states must implement the NAAQS, but instead provides broad directives regarding how states must go about obtaining compliance with the NAAQS. TNACC stated that the NAAQS do not provide in and of themselves any standards applicable to the regulated community, and that a state with an approved SIP has broad flexibility on how to meet the NAAQS. CPS asserted that the proposal exceeds a standard set by federal law, such as the acid rain deposition control program of 40 CFR 76 (Acid Rain Nitrogen Oxides Emission Reduction Program). TNACC stated that the commission failed to cite "an 'express requirement of state law' that justifies the promulgation of the proposed rule without complying with the mandates of §2001.0225."

TNACC and TXU stated that the rules were proposed solely under the under the general powers of the commission and noted that the rule proposal preamble states that the rules were proposed under Texas Health and Safety Code, TCAA, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; and §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air, such as the SIP. TNACC stated that none of these provisions is an express requirement of state law to adopt NO_x emission reductions for the cement industry.

CEED, CPS, CSW, Holnam, and NACC further stated that because Texas Government Code, §2001.0225(a)(2), requires that rules not expressly required by state law must be specifically required by federal law and not merely developed to meet federal law, the commenters believed that the requirements of §2001.0225 do apply to the proposed rules. Holnam asserted that to allow the commission to claim that it is not required to conduct a regulatory analysis and prepare a draft impact analysis for any rule specifically developed to meet the NAAQS would render §2001.0225 meaningless because the commission could argue that any of its rules are somehow related to its efforts to meet the NAAQS. CPS stated that the absence of an RIA "serves to frustrate the intent of the Legislature in enacting section §2001.0225." CSW asserted that the commission will not be able to comply with the procedural requirements of Texas Government Code, §2001.033 and §2001.035, because inadequate technical and scientific support exists for the proposal, especially the NO_x limits for coal-fired power plants. TNACC stated that the proposed rules are invalid because the commission "proposed these rules without quantifying the costs and benefits or describing reasonable alternative methods for achieving the purpose of the rule, as required by §2001.0225."

Although the commission has determined that this is a major environmental rule because it may adversely impact in a material way a sector of the economy, the commission is not required to perform an RIA because the rules do not meet any of the criteria listed in Texas Government Code, §2001.0225(a). The rules do not exceed a standard set by federal law or state law. The

standard in this case is the NAAQS for ozone. The state is required to demonstrate compliance with this standard under federal law, 42 USC 7410, and under state law, TCAA, §382.012. As shown in the modeling for the SIP that is associated with this control strategy, the state is requiring no more emission reductions than absolutely required to meet the standard. Additionally, these rules would not exceed a requirement of a delegation agreement or contract with the federal government because none exists on this topic. Finally, the rules have not been proposed under the general powers of the agency but instead have been proposed under the specific state laws found in TCAA, §§ 382.011, 382.012, and 382.017. Section 382.012 is a specific requirement to maintain the SIP.

The commenters have stated that the commission cannot avoid the requirement to perform an RIA simply by saying that if a rule is needed for SIP purposes, then the rule is federally mandated. Section 7410 of the FCAA requires states to adopt a SIP which provides for "implementation, maintenance, and enforcement" of the primary NAAQS in each air quality control region of the state. While §7410 does not require specific programs, methods, or reductions in order to meet the standard, state SIPs must include "enforceable emission limitations and other control measures, means or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance as may be necessary or appropriate to meet the applicable requirements of this chapter," (meaning Chapter 85, Air Pollution Prevention and Control). It is true that the FCAA does require some specific measures for SIP purposes, like the inspection and maintenance program, but those programs are the exception, not the rule, in the SIP structure of the FCAA.

The provisions of the FCAA recognize that states are in the best position to determine what programs and controls are necessary or appropriate in order to meet the NAAQS. This flexibility allows states, affected industry, and the public, to collaborate on the best methods for attaining the NAAQS for the specific regions in the state. Even though the FCAA allows states to develop their own programs, this flexibility does not relieve a state from developing a program that meets the requirements of §7410. Thus, while specific measures are not generally required, the emission reductions are required. States are not free to ignore the requirements of §7410 and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Therefore, adopting the SIP rules is specifically required by federal law.

Additionally, the legislative history contradicts the conclusion of the commenters that a full RIA is required of these rules. The requirement to provide a fiscal analysis of proposed regulations in the Texas Government Code were amended by Senate Bill 633 (SB 633) during the 75th Legislative Session. The intent of SB 633 was to require agencies to conduct an RIA of extraordinary rules. These are identified in the statutory language as major environmental rules that will have a material adverse impact and will exceed a requirement of state law, federal law, or a delegated federal program, or are adopted solely under the general powers of the agency. With the understanding that this requirement would seldom apply, the commission provided a cost estimate for SB 633 that concluded "based on an assessment of rules adopted by the agency in the past, it is not anticipated that the bill will have significant fiscal implications for the agency due to its limited application." The commission also noted that the number of rules that would require assessment under the provisions of the bill was not large. This conclusion was based, in

part, on the criteria set forth in the bill that exempted proposed rules from the full analysis unless the rule was a major environmental rule that exceeds a federal law. As discussed above, the FCAA does not require specific programs, methods, or reductions in order to meet the NAAQS; thus, states must develop programs for each nonattainment area to ensure that area will meet the attainment deadlines. Because of the ongoing need to address nonattainment issues, the commission routinely adopts SIP rules. The legislature is presumed to understand this federal scheme. If each rule proposed for inclusion in the SIP was considered to be a major environmental rule that exceeds federal law, then every SIP rule would require the full RIA contemplated by SB 633. This conclusion is inconsistent with the conclusions reached by the commission in its cost estimate and by the Legislative Budget Board (LBB) in its fiscal notes. Since the legislature is presumed to understand the fiscal impacts of the bills it passes, and that presumption is based on information provided by state agencies and the LBB, the commission believes that the intent of SB 633 was only to require the full RIA for rules that are extraordinary in nature. While the SIP rules will have a broad impact, that impact is no greater than is necessary or appropriate to meet the requirements of the FCAA. For these reasons, rules adopted for inclusion in the SIP fall under the exception in Texas Government Code, §2001.0225(a), because they are specifically required by federal law.

CPS and CSW asserted that the commission had not provided a "reasoned justification" for the proposal. CSW and NACC asserted that consequently the commission can not finalize the Chapter 117 rule proposal and that the proposal must be withdrawn and reproposed.

The commission has provided a "reasoned justification" for the rules in this adoption package as required by Texas Government Code, §2001.033. Only a brief explanation of the rule is required upon proposal in addition to other elements such as the fiscal note and public benefit evaluations. See Texas Government Code, §2001.024. Both the rule proposal and adoption meet all of the requirements of the Administrative Procedure Act (APA). Therefore, it is not required that this rule be withdrawn and reproposed.

Austin, Brazos, Bryan, CAAC, Capitol, CEED, CSW, Dow, ED, Holnam, LCRA, LWVTX, NACC, OPG, Reliant, San Miguel, Tenaska, TCC, TMPA, TNACC, TPPA/ED, and TXU urged the commission to adopt a regional NO_x trading program as soon as possible and provided suggestions they wished included in such a program. Brazos suggested that the commission delay adoption of the proposed Chapter 117 rules such that a banking and trading rule could be adopted concurrently.

As noted earlier in this preamble, comments on emission trading will not be addressed as part of this rulemaking, but will be addressed when the commission considers its banking and trading program during summer 2000. The commission held stakeholder meetings to discuss the comments received and solicit input before formally proposing an emissions banking and trading program, estimated to occur sometime during summer 2000. The commission's goal is to adopt rules for an emissions banking and trading program no later than December 2000. Due to APA constraints, the commission must file final action on the Chapter 117 with the *Texas Register* no later than June 30, 2000 or the proposal will be automatically withdrawn. Additionally, if the commission delayed adoption of the proposed Chapter 117 rules such that banking and trading

rules could be adopted concurrently, the commission would be unable to submit the final Chapter 117 rules to the EPA with the DFW Attainment SIP by the April 30, 2000 deadline, thereby potentially resulting in sanctions under the FCAA.

CAAC and nine individuals expressed concern about enforcement of the proposed rules, and three of these individuals recommended high penalties for noncompliance.

The commission agrees that adequate enforcement is critical to the success of the program. As with all of its rules, the commission will enforce the requirements after the compliance date and take appropriate action for noncompliance situations.

CEED, CPS, NACC, and TXU commented that power plants in east and central Texas comprise only part of the inventory of NO_x emission sources. CEED stated that the commission should consider requiring reductions at other NO_x sources before requiring power plants to reduce NO_x emissions. NACC stated that coal-fired EGFs in east and central Texas emit 709 tpd of NO_x (based on 1998 EPA CEMS data), while elevated point sources which are largely exempt emit 420 tpd or nearly 60% as much as coal-fired EGFs. CPS, CWS, LWVTC, NACC, Steering Committee, SCATC/SPAC, TXU, and two individuals stated that emission reductions should be required in east and central Texas from larger stationary sources of NO_x other than cement kilns and power plants. One of the individuals recommended a 90% NO_x reduction requirement for all major sources in the eastern half of the state. Tyler supported obtaining additional NO_x reductions from larger stationary sources of NO_x other than power plants that are beneficial in helping to meet the ozone standard. CPS further suggested that under a broad cap-and-trade program these non-utility point sources could easily be required to achieve a specified percentage reduction in NO_x. CSW believed that it was "arbitrary, improper, and unfair" that the proposed rules only apply to EGFs and cement kilns, and stated that other NO_x source categories are responsible for about 33% of the total point source NO_x emissions in east and central Texas and potentially cause more ozone in nonattainment areas due to their proximity to these areas.

Cemex and TNACC stated that cement plants in east and central Texas comprise only part of the inventory of NO_x emission sources. Cemex stated that the commission should not include cement plants in central Texas as part of a regional strategy to reduce NO_x emissions, while TNACC asserted that the cement industry was arbitrarily targeted for NO_x reductions. TNACC stated that the nine cement plants targeted by the rules emit only 56.12 tpd and are less than 5.0% of the total NO_x emissions from point sources in the 95 east and central Texas attainment counties. TNACC also suggested that cement plant emissions are insignificant compared to EGF emissions in these counties. Finally, TNACC stated that none of the nine cement plants targeted by the rules are in counties that are nonattainment for ozone and suggested that this demonstrates that something other than cement kiln NO_x emissions are responsible for the nonattainment status of DFW and other ozone nonattainment areas.

Commission staff reviewed the 1997 emissions inventory and note that 12 of the 13 largest stationary NO_x sources in the 95 east and central Texas attainment counties are power plants. In fact, the category of electric utilities (Standard Industrial Classification (SIC) code 4911) is the largest stationary source of NO_x emissions in these counties. Therefore, the commission does not

agree with CEED's contention that reductions from non-utility NO_x sources should be required before power plants.

Commission staff reviewed the 1997 emissions inventory and note that cement plants represent 26.1% of the permitted non-utility stationary NO_x sources in the 95 east and central Texas attainment counties and 13.7% of the total (permitted and grandfathered) non-utility stationary NO_x sources in these counties. Because cement plants are one of the largest stationary sources of NO_x emissions in the east and central Texas and because modeling has demonstrated that NO_x reductions from these sources are beneficial for meeting the one-hour ozone standard in DFW as well as in the east and central Texas counties, the commission believes it is appropriate to include these cement plants as part of a regional strategy to reduce NO_x emissions.

The commission agrees that non-utility NO_x sources should also be targeted and has already done so. For example, the commission is adopting NO_x limits for cement kilns and has negotiated agreed orders with other major non-utility NO_x sources in these counties which will result in substantial NO_x reductions. The commission may consider future rulemaking to address possible NO_x emission reductions from non-utility, non-cement kiln stationary point sources. As noted earlier in this preamble, the commission expects to propose a banking and trading program during summer 2000.

Regarding TNACC's last comment, the commission notes that TNACC is in effect suggesting that NO_x emissions from cement kilns do not contribute to ozone formation in the ozone nonattainment

areas. The commission believes that the modeling and monitoring data described elsewhere in this preamble demonstrate that NO_x emissions from cement kilns do in fact contribute to ozone formation in the ozone nonattainment and near-nonattainment areas.

TNACC stated that mobile source emissions are the source of ozone problems in DFW and other ozone nonattainment areas and stated that until mobile source emissions are dramatically reduced, additional point source controls are a questionable measure.

Mobile source emissions make varying contributions to ozone formation in the ozone nonattainment and near-nonattainment areas. There is no question that the largest contributor of ozone precursors in DFW is the mobile source category, but there is no basis for TNACC's conclusion that point source controls are not beneficial in making progress toward attaining the ozone NAAQS, as demonstrated by the modeling described elsewhere in this preamble. The commission agrees that mobile source emissions need to be reduced and has incorporated a variety of state and federal mobile source rules which will result in cleaner-burning gasoline, cleaner-burning diesel fuel, cleaner heavy diesel equipment, cleaner large gasoline engines, cleaner new motor vehicles, an improved program for inspection and maintenance of motor vehicles, and a voluntary scrappage program to retire high-emitting motor vehicles.

TNACC stated that the cement industry was targeted as part of the commission's ozone strategy solely because a set of controls developed by the Steering Committee for addressing the ozone nonattainment status in DFW included a recommendation for up to 50% NO_x reductions from Ellis County cement kilns. TNACC expressed concern that Ellis County was not represented on the Steering Committee and suggested that the Ellis County cement plants were targeted because they are not in the DFW ozone nonattainment area, even though the Steering Committee's consultant, Environ, "believed the contribution of Ellis County cement plants to the DFW Area ozone problem to be negligible."

The commission disagrees with the commenter. The Ellis County cement plants were targeted as part of the DFW ozone control strategy because the modeling described earlier in this preamble revealed that these plants are contributing to the DFW ozone problem and that reductions from this industry are beneficial in making progress toward attaining the ozone standard. While it is true that the modeling performed by Environ incorporates some improvements over the commission's earlier regional modeling analyses, the commission does not agree that Environ's work supercedes the earlier work. Environ's analysis in no way contradict's the commission's conclusions that a 50% reduction in point source NO_x emissions would lead to reductions in peak ozone of between 14 and 27 ppb.

CEED, CSW, NACC, and TNACC commented on the discussion in the rule proposal preamble concerning improvements in the eight-hour ozone levels in Tyler, Longview, Austin, and much of the upper Texas Coast. CEED, CSW, NACC, and TNACC stated that no eight-hour standard exists because this standard has been struck down in federal court.

It is true that the EPA may be unable to enforce the eight-hour ozone standard pending a decision by the United States Supreme Court. The modeling to which the commenters refer was analyzed

for both the one-hour and the eight-hour ozone standards, and the benefits in one-hour ozone concentrations are accompanied by a corresponding improvement in eight-hour ozone levels. The modeling indicates that controls which reduce all elevated point source NO_x emissions by 50% in east and central Texas will reduce peak one-hour ozone between 14 and 27 ppb at specific locations in the region, depending on the modeling day. The one-hour ozone benefits stretch across the east and central Texas counties and average six to seven ppb. Based on a one-hour exceedance design value of 128 ppb, the projected benefits of 50% point source NO_x reductions in the attainment counties of east and central Texas may be large enough to prevent some areas from being reclassified as not attaining the one-hour ozone NAAQS. It is the FCAA requirement for meeting the one-hour standard that forms the basis for the regional NO_x control requirements.

CSW and TNACC also stated that it is inappropriate for one of the rulemaking purposes to be a decrease in one-hour ozone concentrations in the attainment counties of east and central Texas because these one-hour ozone concentrations are currently below the one-hour ozone NAAQS.

As noted earlier in this preamble, additional modeling was completed by commission staff assessing the potential benefits of regional NO_x reductions in the attainment counties of east and central Texas. This modeling indicates that controls which reduce all elevated point source NO_x emissions by 50% in the region will reduce peak one-hour ozone between 14 and 27 ppb at specific locations in the region, depending on the modeling day. The one-hour ozone benefits stretch across the east and central Texas counties and average six to seven ppb. Based on a one-hour exceedance design value of 128 ppb, the projected benefits of 50% point source NO_x reductions in

the attainment counties of east and central Texas may be large enough to prevent some areas from being reclassified as not attaining the one-hour ozone NAAQS.

The primary purposes of the rulemaking are: 1) to help the BPA, DFW, and HGA ozone nonattainment areas move closer to reaching attainment with the ozone NAAQS; and 2) to reduce overall background levels of ozone in order to assist in keeping ozone attainment areas and near-nonattainment areas in compliance with the federal ozone standards. This regional NO_x reduction strategy provides a concurrent benefit of reduced peak one-hour ozone levels in much of east and central Texas. The commission believes that it is appropriate to include a description of these benefits in this preamble.

TXU commented on the discussion in the preamble which stated that the commission's modeling staff ran several sensitivity analyses for Texas using a regional modeling setup based on the COAST study, and that one modeling scenario, OTAG 5c, consisting of reductions across the domain (60% reduction of point source NO_x, 30% reduction of low-level NO_x, and 30% reduction of VOC), indicated that modeled reductions would reduce peak eight-hour ozone by as much as 20 ppb throughout most of the eastern half of Texas. TXU stated that the OTAG regional modeling is only a sensitivity model and is not capable of determining appropriate control levels for a SIP. TXU asserted further that the OTAG 5c study is of little value because the modeled domain reductions (60% reduction of point source NO_x, 30% reduction of low-level NO_x, and 30% reduction of VOC) are not the reductions being proposed in this rulemaking. TXU also stated that the OTAG modeling was based on the eight-hour ozone standard that has been deemed unenforceable in federal court.

The commenter is mistaken in claiming that OTAG's modeling was conducted based on the eight-hour federal ozone standard. In fact, with the exception of selection of episodes, photochemical modeling is conducted independently of the ozone standard. The model outputs predicted ozone concentrations, which can then be analyzed relative to any arbitrary standard. OTAG model output was analyzed both for the one-hour and proposed eight-hour standards.

The commenter also appears to be confused about the difference between modeling conducted by OTAG and regional modeling conducted by TNRCC using the OTAG 5c scenario. As part of the 1998 HGA SIP, the commission reported that applying the OTAG 5c strategy regionally could mitigate the reduction required to meet the one-hour standard in the HGA area by as much as 5.0%. While the OTAG 5c scenario is somewhat more stringent than the proposed regional rules, the commission believes that modeling conducted with the OTAG 5c assumptions is of significant value in assessing the potential benefits of regional NO_x reductions.

CSW and TXU commented that the sensitivity studies discussed in the preamble are based upon old inventories, incorrect biogenics, and have been superseded by more accurate fine grid modeling in central and eastern Texas.

CSW and TXU correctly point out that the original modeling has been updated to include better treatment of point source inventories and biogenics. They are not correct that the newer modeling uses finer grids. The objective of sensitivity modeling is designed to determine the most effective path toward attainment early in the modeling process. Although the early work has been

updated, that fact does not invalidate the earlier work. Further, the updates and improvements have not changed the original directional guidance. The numerous point sources in central and eastern Texas still contribute large amounts of NO_x to the air over Texas, and NO_x controls are still the most effective path toward attainment.

CSW, TXU and TNACC all comment that the existing modeling (the 1995 and 1996 DFW episodes) do not show large contributions to DFW ozone directly attributable to point sources in central and eastern Texas, and that those contributions have not been quantified.

The commission acknowledges that the two current DFW episodes do not show a large contribution from elevated point sources in central and eastern Texas. However, the two current DFW episodes were chosen to evaluate the controls necessary in the DFW area, not specifically to demonstrate transport. The proposed controls are based upon a body of circumstantial evidence from aircraft measurements, seasonal modeling, back trajectories, and statistical studies indicating that electric generating facilities and cement kilns in central and eastern Texas contribute to the background levels of NO_x which impact the DFW area. Documents explaining these additional studies are included as appendices to the SIP.

As pointed out previously, NO_x is the most important single contributor to ozone formation. Although emissions from each point source taken individually may not be significant, in aggregate the point sources contribute to the high background concentrations of NO_x measured in Texas. These high levels of NO_x raise the concentration of ozone transported into DFW which makes it

more difficult for DFW to attain and maintain the ozone standard. The proposed rules are designed to reduce the high background levels of NO_x which affect not only DFW, but impact the ability of many other Texas cities to meet the ozone standard as well.

ED stated that they had the University of Texas (UT) perform regional scale modeling with 75% reductions of NO_x and that this modeling showed larger reductions of ozone in the DFW area.

The regional modeling performed by UT for the commission analyzed reductions of 20%, 30%, 40%, and 50% applied to all point sources east of Interstate 35. It is not possible to evaluate the ED/UT results without reviewing the whole modeling report. The work that ED had performed appears to have excluded the point sources in part of the DFW nonattainment area, but the exact geographical extent is not clear from the information in the comment letter. ED/UT modeled only the 1993 episode which was the episode for urban scale modeling in the HGA area. The 1995 and 1996 episodes which were developed for the DFW SIP development were not modeled by ED/UT. The maximum difference for their modeling was on September 11, 1993 with six ppb for a 50% reduction and eight ppb for a 75% reduction. The maximum modeled one-hour ozone concentration on September 11, 1993 was 116 ppb, significantly below the one-hour ozone NAAQS of 125 ppb. The information from the ED/UT modeling can be added to the information already presented for the other reduction scenarios and considered in making the policy decision for the amount of control that should be applied to each source category.

ED suggested that the commission include the results of the trajectory analysis that was performed and presented at a previous meeting.

Trajectory analyses provide insight into the path an air parcel took prior to arriving at a monitor. However, these analyses do not include information on quantity of source emissions, atmospheric chemical reactions and ozone formation, or response of ozone to various control strategy options. They have been considered for episode selection and development of a conceptual model for high ozone, but should not otherwise be considered in the core information in the SIP as they do not directly address evaluation of control strategy options.

TNACC noted that the Complex Air Quality Model with Extensions (CAMx) photochemical model has the capability of accounting for the dispersion and chemical evolution of individual elevated point source plumes (for example, those emitted from cement kilns). TNACC stated that in the commission's SIP modeling, the number of elevated point sources within the entire modeling domain that were treated as individual plumes in CAMx was limited to about 120 to reduce the computation time and that as a result, only one cement kiln stack in Ellis County was chosen to be modeled in CAMx as a separate plume. The remaining cement kiln stacks in Ellis County were assigned to the 4-kilometer (km) by 4-km modeling grid cell within which the kilns are located. The model then assumed that the emissions from these remaining kilns were uniformly mixed with other emissions in the area throughout the horizontal dimensions of the cell. TNACC asserted that consequently, instead of recognizing each cement kiln plume and individually tracking its transport and photochemical reactions as it entered DFW, the model lost the precise location and identity of all but one of these plumes immediately upon their release into the atmosphere. TNACC asserted further that it was impossible for CAMx to accurately determine either individual or collective contributions of cement kiln plumes to ozone concentrations for the meteorological events examined in the modeling.

The first few sentences of the comment are true, except that *two* of the cement kiln stacks in Ellis County were modeled as discrete plumes in CAMx, not just one. These two stacks happened to be the tallest, the two newest, and two of the largest NO_x sources. Therefore, they met the criteria for treatment with the Plume-in-Grid (PiG) algorithm of the CAMx model. The purpose of the PiG algorithm is not to enable the tracking of transport and photochemical reactions of individual plumes, but to provide a more realistic model for the fate of these larger plumes as they react downwind. It should also be noted that the vertical resolution which is maintained, with or without PiG treatment, depends on the effective plume height achieved by the emissions. Since these point source emissions are modeled at various levels in the atmosphere, they are not simply allowed to mix with all other emissions in the grid cell, until the meteorological conditions allow such.

In the last sentence of the comment, the commenter asserts that because the Ellis County sources were not treated individually as PiG sources, their individual or collective contributions cannot be accurately assessed. While there is always some uncertainty in the modeling predictions, the analyses performed by the commission employ the accepted methodologies for simulating ozone formation in an urban area. By performing CAMx model runs with and without the cement kilns included and then taking the difference in predicted ozone contributions, the commission has

developed a reasonable assessment of the contribution of the Ellis County cement kilns toward ozone formation in the DFW area. More detailed analysis of these specific sources would require a special modeling study directed at these sources, which could be costly and could not be completed in time for this SIP.

TNACC asserted that the commission did not analyze the sensitivity of ozone concentrations to reductions in emissions from the cement kilns in the modeling. TNACC commented that the science of atmospheric photochemistry has shown repeatedly that not all reductions in the emissions of ozone precursors result in reductions in ambient ozone concentrations and stated that in one of its periodic project updates on the DFW photochemical modeling effort, the firm hired by the North Central Texas Council of Governments (NCTCOG) to perform the CAMx modeling stated that the real issue is not what control measures will achieve in terms of reductions in emissions of ozone precursors but what effect will they have in terms of ozone formation. TNACC asserted that there is no evidence that the commission examined each emissions control option in terms of its part-per-billion contribution to reduced ozone concentrations and that instead, most of the modeling scenarios included more than one change in mitigation measures. TNACC asserted that as a result it was not possible to determine what modeled changes in ozone concentrations would result from each of the proposed measures.

Analyzing the sensitivity of ozone concentrations to reductions in emissions from cement kilns was *not* one of the goals of CAMx modeling for this SIP. The commission agrees that it is always a goal of ozone photochemical modeling to predict what effect the combinations of ozone precursor emissions will have in terms of ozone formation. It is not feasible for the commission to examine

each control option proposed by all interested parties in terms of amount of predicted ozone reduced. It is the combination of controls (not individual controls) that affects the chemistry in an area. Therefore, the commission does not emphasize individual control options when they are not modeled within the likely control scenario for the entire area. Furthermore, the effects of individual measures change, depending upon what other control options are assumed. For instance, the effectiveness of an individual NO_x control measure may increase if it is applied in concert with several other rules. It is therefore not feasible to assess the effectiveness of each individual proposed control measure. Hence, it is true that most of the modeling scenarios included more than one change in mitigation measures. It is never the intention of the commission to single-out any one class of controls or any single area with which to apply controls.

With regard to the commission's use of NCTCOG modeling, TNACC asserted that the commission did not properly treat or sufficiently analyze the emissions from cement kilns to identify the effectiveness of reducing their emissions. TNACC further stated that the commission did not account for the specific characteristics of individual cement kiln releases in its modeling and did not analyze the sensitivity of ozone concentrations to reductions in emissions from the cement kilns in the SIP modeling

The commission made a sensitivity model run with zero-out (removal of all emissions) for the cement kilns. This information was presented at one of the modeling oversight committee meetings. The results of the zero-out modeling on ozone in the DFW area were: 1) maximum concentrations were reduced by a small amount; 2) the maximum difference found was 11 ppb; 3) the values for the aerial extent was reduced (the size of the area of exceedance was significantly

reduced); and 4) the values for the exposure metric were significantly reduced. It is not practical for the commission to make a sensitivity model run for each specific control strategy. Also, by itself there may not be a large response for the implementation of any specific control, but it is the result of the ensemble of all controls that is effective in reducing ozone concentrations.

TNACC stated that none of the 23 emission control scenarios the commission modeled isolated the effects of reducing cement kiln emissions alone. TNACC commented that the effects of NO_x emissions reductions in Ellis County were first modeled as Control Strategy D11, but that Ellis County emissions were not the only ones changed from the previous modeling. Rather, the changes between Strategies D10 and D11 included reducing emissions due to construction equipment start time delays and reducing emissions due to implementation of a voluntary mobile emissions program.

The first sentence of this comment is incorrect. At the time of the submittal of the proposed SIP and the accompanying rules, the commission had run 30 modeling scenarios. The TNACC's consultants were provided with an early modeling scenario (D2) in which the only change was cement kiln reductions. This scenario was not included in the SIP because the base case was revised subsequent to strategy D2 to include proposed controls in the surrounding areas and to make several improvements to the modeling. If the surrounding area controls had been included (essentially yielding a smaller background) in the modeling of strategy D2, then the differences observed due to Midlothian reductions could have been more pronounced. Were the analysis to be repeated using more recent modeling scenarios, the commission expects the results would still show meaningful reductions in peak and aerial coverage of predicted ozone concentrations, as did

the results provided to TNACC's consultant. The commission drew no conclusions regarding Ellis County from Control Strategy D11.

TNACC also stated that in Control Strategy D19, when a 50% reduction in Ellis County NO_x reductions was first considered (as opposed to a 30% reduction in Ellis County NO_x emissions as examined in the previous CAMx run), the following changes were made to the CAMx inputs: building code modifications were included, vehicle recycling was raised from 3,000 to 5,000 cars per year, construction equipment was delayed only until 8:30 a.m., no use of very low-sulfur fuel in mobile sources was considered, and the use of low-NO_x water heaters was added. TNACC stated that the changes proposed for Control Strategy D19 (which included a decrease in Ellis County cement kiln NO_x emissions) resulted in a modeled *increase* in the peak ozone concentration of 2.5 ppb. TNACC commented that it is impossible to tell from the modeling runs for Control Strategies Dl8 and Dl9 how the reduction in the cement kiln emissions affected the modeled ozone concentrations, if at all.

The commission drew no conclusions regarding Ellis County from Control Strategy D19. It was not the intent of this scenario to quantify ozone reductions from Ellis County.

TNACC commented that in Control Strategy D29, one of the changes to the model inputs was to include reductions in emissions from cement kilns in east and central Texas, based on the proposed changes to Chapter 117. TNACC stated that these changes resulted in a modeled peak ozone concentration increase of 0.2 ppb. TNACC stated that it is impossible to tell from the modeling whether reductions in emissions from cement kilns located outside of Ellis County contributed to

DFW's ozone problem, or whether the modeled increase in ozone concentrations between Scenario D28 and D29 was due to other factors.

The commission drew no conclusions regarding Ellis County from Control Strategy D29. It was not the intent of this scenario to quantify ozone reductions from Ellis County.

TNACC commented that limitations in the Baylor aircraft monitoring may prevent the monitoring data from providing support for the proposed reductions in NO_x emissions from cement plants in the east and central Texas region. Specifically, TNACC asserted that Sonoma Technologies (Sonoma), the firm the commission hired to evaluate the Baylor data, did not evaluate the data from a "downwind" perspective, but instead looked at the air flow coming into the urban areas. TNACC stated that Sonoma's data review was aimed at determining what was coming into the DFW area, not where or what it was coming from, and that Sonoma did not attempt to determine if regional long-range transport was occurring.

Determination of long-range transport was never one of the stated objectives of flights that Sonoma analyzed. Sonoma was asked to review regional (i.e., East Texas) ozone production and its contribution to ozone in and downwind of major urban areas in Texas. Sonoma did this by comparing ozone levels measured upwind and to ozone levels measured downwind of the DFW area and assuming the difference was produced by the urban area. Sonoma found that, on average (six cases), the DFW area's local contribution was approximately 65 ppb (or 50%). Since

Sonoma was concerned with general regional ozone levels and not any particular wind directions, their upwind/downwind approach was appropriate.

TNACC asserted that of the 91 Baylor flights flown, only the data from one (Flight Number 39) indicated any real evidence of regional transport. TNACC stated that the Flight Number 39 data allowed tracking of a sulfur dioxide (not NO_x) plume, thought to be from the Big Brown power plant, for approximately 80 kilometers (km) downwind, but that there was no conclusive evidence of transport other than this one flight. TNACC asserted that there is nothing in the Baylor aircraft monitoring data which demonstrates that long-range transport exists at all beyond 80 km (50 miles).

Fewer than half the flights flown by Baylor University have been quality assured and analyzed so to say that only one out of 91 flights contained evidence of transport is inaccurate. Sonoma was only able to track the sulfur dioxide plume from the Big Brown power plant out to 80 km because the aircraft never attempted to track the plume out any further on this particular flight. Data exists to plot a NO_x plume, but this task simply has not been done. TNACC's comments are based on an incomplete review of the data. Work has been done under the Southern Oxidants Study indicating that power plant plumes can extend up to 200 km in the day and even longer overnight. Regional transport can occur over hundreds of miles.

TNACC stated that the results of the Baylor aircraft monitoring study provide no basis for concluding that ozone levels monitored at the aircraft's sampling altitude (approximately 2,000 feet) would reach the ground in the same concentrations.

Comparison of ground monitoring data with airborne pollutant levels suggests that airborne data compares relatively well to ground-based data. Baylor aircraft flights are planned so the aircraft is being flown at a time and an altitude in which the atmosphere is mixed. In these conditions, pollutant levels can usually be assumed to be fairly uniform from ground height all the way up to the "mixing layer." Also, the aircraft usually performs more than one up-and-down spiral precisely for the purpose of measuring how pollutant levels change in the vertical. Consequently, any changes in pollutant levels can be identified and taken into account.

TNACC also commented that the data only represent a snap-shot in time of the concentrations of ozone, NO_x, and other air contaminants at an altitude of approximately 2,000 feet and that as a result, the data do not demonstrate or even indicate what the concentrations of such air contaminants would be at a later time or day after mixing and/or dispersion has occurred.

While it is true that a given pollutant measurement point is only a "snap-shot in time," the same could be said for any single measurement point at ground monitoring site. Baylor University's airborne monitoring platform has several capabilities which allow it to overcome this "limitation." First, the Baylor aircraft can, and does, fly over the same latitude and longitude coordinates more than once in a given flight which means that it has the ability to measure pollutants at a single point over time. Second, since the aircraft moves, it can, and does, track a particular "parcel" of air throughout the day as it moves through a geographic area and disperses. Third, because the aircraft can climb and descend, it can, and does, measure vertical changes in pollutant levels.

Additionally, the aircraft is often flown during a time of the day when the atmosphere is relatively well-mixed so that differences with ground-based monitors can be further minimized.

TNACC further stated that meteorological conditions (e.g., wind speed and direction) associated with the aircraft monitoring were not always known or were so variable as to limit or eliminate the value of the data for the proposed NO_x emission limits. As examples, TNACC cited the descriptions of Flight Number 61 (flown on July 17, 1998), which it stated was the primary basis for the commission staff's belief that NO_x emissions from point sources in the Tyler/Longview area are contributing to ozone concentrations in DFW, and of Flight Number 42 (flown on August 28,1997), which was also flown around the Tyler/Longview area. TNACC commented that the descriptions state that "there are no data available to describe the winds [direction or speed] at 2,000 feet, the aircraft altitude," and that during the flight, surface winds shifted quite a bit, both in time and over space. TNACC commented that both flight descriptions stated that "conclusions about source attribution during the flight are necessarily tentative."

While it is true that having wind data collected by the aircraft during its flight is the preferred mode of operation, the inability to do so does not prevent the Baylor aircraft from providing important information. Indeed, the commenter is only able to cite two examples where conclusions were rendered tentative by the lack of such data. When this is put in the context of the number of flights analyzed by Sonoma, it becomes clear that existing data is sufficient to allow analysts to reach firm conclusions in the large majority of cases. Also, additional resources such

as ground monitoring data, meteorological models, and radar data can provide important wind information needed to interpret flight data.

TNACC stated that the aircraft monitoring data do not indicate whether, and if so, how much, the proposed cement kiln NO_x emissions reductions will reduce one-hour ozone concentrations in DFW or any other area of the state. TNACC stated that the data do not indicate what percentage of NO_x emissions reductions in the east and central Texas region are needed to allow the commission to demonstrate attainment with the one-hour NAAQS in DFW or any other nonattainment area, or to prevent near-nonattainment areas from becoming nonattainment with the one-hour ozone NAAQS.

While this comment is true, the airborne monitoring program was never intended to quantify the effect of emissions reductions. What the program does show, however, is that regional ozone levels account for approximately 50% of the peak ozone concentration in the DFW area. This indicates that regional ozone production plays a crucial role in determining peak ozone concentrations inside the DFW area.

TNACC further asserted that the airplane monitoring data do not demonstrate how much of the measured ozone concentrations is due to mobile sources in the area, or to other NO_x point sources.

Based on their analysis of Baylor aircraft data, Sonoma determined that point, area, and mobile sources contribute almost equally to regional ozone concentrations.

NFN, TCEA, and 18 individuals stated that facilities that predate the commission's air permitting requirements (i.e., those that are "grandfathered") should be subject to the NO_x limitations.

The proposed NO_x limits for cement kilns and utility boilers and stationary gas turbines apply to both permitted and non-permitted ("grandfathered") sources in the eastern half of the state. This is the area for which air quality modeling and upper air monitoring with aircraft found that regional air pollution should be considered concerning the impact on ozone nonattainment and near-nonattainment areas. The commission has made no change in response to the comment.

Representative Merritt encouraged the commission to recognize the benefits of utilizing technologies and fuels such as cogeneration and natural gas as methods to reduce NO_x emissions from EGFs as outlined in SB 7.

The proposed rules do not specify a required technology or fuel. Instead, the commission proposed emission limits for EGFs which represent NO_x emission reductions of approximately 50%. Establishing emission limits provides more flexibility so that individual utility boilers and stationary gas turbines can be evaluated to determine the most cost-effective approach to reducing NO_x emissions.

Dallas Sierra Club, DAR, ED, GPTC, NFN, TPC, and 15 individuals supported retiring the oldest and highest-emitting power plants and/or cement kilns. DAR commented that wet process cement kilns generally emit more NO_x than dry process cement kilns (including preheater, precalciner, and preheater-precalciner kilns), and that no new wet kiln has been built in more than 20 years. DAR asserted that wet process kilns are obsolete and that reasonably available control technology (RACT) for cement kilns should be dry process kilns.

The commission agrees that retiring older, higher-emitting units and replacing them with modern units often results in a reduction in emissions. In some cases, however, the increased activity rate of a new unit results in an increase in emissions, even though the emission rate per quantity of product is far lower than that of the unit being replaced. Rather than mandate the retirement of older units, the commission believes that it is more appropriate to set emission limits for these units, thus providing more flexibility so that the owners or operators can evaluate individual units to determine the most cost-effective approach to reduce NO_x emissions.

Regarding DAR's comments, there is no question that new dry process cement kilns (including preheater, precalciner, and preheater-precalciner kilns) are more energy efficient and produce fewer NO_x emissions per ton of clinker produced as compared to wet process kilns. However, the FCAA definition of RACT specifically refers to "retrofit equipment," while the EPA has defined RACT in a variety of guidance documents 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." As such, RACT for an existing source can not be established as a complete shutdown and replacement of the existing source. Regardless, the cement kiln rules were not proposed to implement RACT. Rather, these rules were proposed to reduce NO_x emissions which impact ozone nonattainment and near-nonattainment areas.

Burroughs and FWCC recommended giving consideration to the level of reductions feasible for power plants so as not to affect the system reliability, while the Steering Committee recommended giving consideration to the level of reductions feasible for older and smaller power plants so as not to affect the system reliability.

A January 1999 joint Public Utility Commission of Texas (PUCT)/TNRCC report, "Electric Restructuring and Air Quality: A Preliminary Analysis of Reductions and Costs of NO_x Controls from Electric Utility Boilers in Texas," analyzed impacts of three levels of NO_x control on electric generating units owned by the major utilities in Texas and found that only a few units would likely be forced to retire at the highest level of control because the cost of controls would make their power production costs uneconomical. The study was a high level report, but is one of the few available indicators of the potential for unit shutdowns. The commission considers the study one indicator that the economic impacts of the proposed emission limits will not result in widespread shutdowns. A definitive analysis of which units may be shutdown is not feasible because such analysis is highly dependent on the future price of power in the area, which depends on such factors as future demand, fuel costs, which new power projects go into operation, and the influence of a more competitive market for electricity. The commission has addressed the commenters' concerns by extending the compliance date to May 1, 2005 for units owned by utilities which are not subject to the May 1, 2003 cost-recovery deadline in SB 7 (Texas Utilities Code (TUC), §39.263(b)).

Reliant requested inclusion of a PURA determination statement in the adoption preamble which would specify that the reductions meet the criteria for stranded cost recovery under SB 7.

The commission agrees and has included such a statement in the preamble.

Reliant stated that the preamble should specify that the standard permit under 30 TAC Chapter 116, §116.617 (Standard Permit for Pollution Control Projects) is available to authorize control technology improvements.

The commission expects that most projects necessary to meet the new Chapter 117 requirements for EGFs and cement kilns will be able to qualify for the standard permit available under §116.617. The commission has revised the preamble accordingly.

No comments were received on the definition of "electric power generating system" in §117.10. However, it has come to the commission's attention that this definition may not clearly enough specify that an electric power generating system encompasses the units in a single ozone nonattainment area, or in the 31 listed attainment counties of east and central Texas. The commission has revised the definition accordingly.

EMA commented on the definition of "maximum rated capacity" in §117.10 and stated that the reference to "Diesel Equipment Manufacturer's Association" (DEMA) conditions in subparagraph (D) should be changed to "International Standards Organization (ISO)" conditions. EMA suggested this change because it believes that DEMA and that this association's conditions now reflect the use of outmoded technology.

Because many existing units have already used the DEMA conditions to establish their rating, the commission has revised the definition of "maximum rated capacity" to reference both DEMA and ISO conditions. This will allow existing units to continue using their already-established rating while also addressing newer units.

As part of their comments on the proposed 30 TAC Chapter 117 rules identified as Rule Log No. 1999-056-117-AI (24 TexReg 11977, December 31, 1999), Denton/Garland suggested that definitions of "large DFW system" and "small DFW system" be added to §117.10.

Denton/Garland's reasoning for the suggested definitions and the commission's evaluation of these comments are found in the preamble for the final 30 TAC Chapter 117 rules identified as Rule Log No. 1999-056-117-AI which is published elsewhere in this issue of the *Texas Register*. In response to these comments, the commission has added definitions of "large DFW system" and "small DFW system" as new §117.10(18) and (36), respectively, and has renumbered other definitions in §117.10 accordingly.

It has come to the commission's attention that Hays County was misspelled in the definition of "major source" in §117.10. The commission has corrected this definition.

EMA commented on the definition of "stationary internal combustion engine" in §117.10 and stated that this definition includes engines that are otherwise classified as mobile nonroad engines under federal law. EMA stated that language from 40 CFR Part 89 (Control of Emissions from New and In-Use Nonroad Engines), §89.2 (Definitions), should be incorporated into the definition of "stationary internal combustion engine."

The commission has revised the definition of "stationary internal combustion engine" using language from 40 CFR 89.2 to clarify the distinction between stationary and mobile nonroad engines.

It has come to the commission's attention that the definitions of "30-day rolling average" and "24-hour rolling average" in §117.10 contain a redundant phrase (specifically, "as the average"). The commission has corrected these definitions.

Austin stated that §117.131 appears to conflict with the trading provisions included in §39.264 of SB 7 and should be harmonized with the legislative intent of SB 7. Austin also stated that the proposed rules should be revised to include the trading program of SB 7.

The commission disagrees that there is a conflict with SB 7. However, as described elsewhere in this preamble, the commission has revised the system cap of §117.138 to facilitate trading within an electric power generating system until the forthcoming emission banking and trading program is finalized. The commission expects that the forthcoming banking and trading program will

lower the cost of compliance and ultimately will be the preferred compliance option for affected EGFs because such a program will allow overcontrol of the more cost-effective units to be applied to units which are less cost-effective. The commission has made no change in response to the comment.

CEED, NACC, and Tenaska commented on §117.131 and suggested that the requirements only apply during the ozone season. CEED and NACC stated that year-round reduction does not affect ozone levels during the ozone season. CEED and NACC cited as precedent rules in 30 TAC Chapter 114 that only apply during the ozone season, while Tenaska commented that the emission limitations proposed for the Section 126 petition and Ozone Transport Commission states are seasonal.

The issue of seasonal controls involves significant air quality considerations. The season for the one-hour ozone standard in DFW has been defined by EPA policy by the monitoring period in 40 CFR Part 58, Appendix D and by commission rule in §101.29(a)(19) of this title, relating to General Air Quality Rules, as an eight-month period from March 1 through October 31. For BPA and HGA, the season for the one-hour ozone standard has been defined as year-round by EPA policy by the monitoring period in 40 CFR Part 58, Appendix D and by commission rule in §101.29(a)(19). Although exceedances of the one-hour standard in DFW generally have been limited to the five months of June-October, there may be ozone and other environmental benefits to year-long NO_x control in DFW. Regional transport may move DFW NO_x southerly into areas with more of a year-long potential for ozone exceedances, such as BPA and HGA. Year-long controls could help prevent current near-nonattainment areas from becoming nonattainment

under the ozone NAAQS. Locally, year-long controls would reduce nitrates in the winter season. Nitrates contribute to the winter visibility impairment in DFW sometimes called the white or brown cloud. In addition, NO_x adds to the nitrification of surface waters, an adverse ecological impact which at times may contribute to algae buildup and related problems.

Weighed against the potential approvability issues and loss of environmental benefits are the reductions in costs and effort that seasonal NO_x controls would offer. The commission expects that the proposed emission limits will be complied with in many cases through the use of additional combustion controls, for which the expense is primarily capital rather than operating. Capital costs must be incurred regardless of the length of the compliance season. The primary benefit to the regulated community of an eight-month compliance season would be a reduced compliance effort during a portion of the normal unit outage period, when test firing with fuel oil and other scheduled maintenance may occur. While not minimizing these efforts, the fact that there has been a documented visibility problem in DFW in the winter in particular has to be weighed carefully against the additional effort. In this regard, year-long compliance makes sense and is consistent with the application of Chapter 117 elsewhere in the state. The commission has made no change in response to this comment.

Tenaska commented that the terms "independent power producer" and "utility electric power boiler and stationary gas turbine" are used in §117.131 but are not defined in §117.10. Tenaska stated that this creates uncertainty as to whether or not the Tenaska units 1 and 2 in Paris are subject to the proposed rules. Tenaska also suggested that the commission clarify whether "exempt wholesale generators," as this term is defined by the Federal Energy Regulatory Commission (FERC), are subject to the proposed rules. Tenaska stated that the concepts of qualifying facilities and exempt wholesale generators have explicit regulatory meaning recognized by FERC and PUCT.

Tenaska units 1 and 2 are subject to the proposed rules, although it should be noted that these units are currently permitted at 42 ppmv NO_x, which is equivalent to the proposed limit of 0.15 lb NO_x/MMBtu in §117.135(2)(B) and (C). The commission believes that it is clear that the rules apply to boilers and stationary gas turbines used to generate electric power which were placed into service before December 31, 1995, and that cogeneration units are subject to the rules. It should be noted that appropriate exemptions are included in §117.133. The commission has made no change in response to the comment. However, the commission has added the phrase "or any of its successors" to §117.131(2) for consistency with the definition of "electric power generating system" in §117.10.

San Miguel suggested that §117.131 be revised to apply statewide, rather than to just selected counties in east and central Texas. San Miguel stated that it was unfair that the power plants in east and central Texas were subject to the limits while those elsewhere in Texas were not. San Miguel expressed concern that limiting the rules to only certain counties will limit competition in the electric utility industry.

The commission can not revise §117.131 upon adoption to apply statewide in this rulemaking because the newly affected parties in the western half of Texas would not have had adequate

notice and opportunity to comment. Regarding the commenter's assertion that the rules are unfair to power plants in the eastern half of Texas and will affect competition in the electric utility industry, the rules are targeting the eastern half of the state because modeling (described in detail elsewhere in this preamble) has shown that NO_x emissions from sources in that area are contributing to exceedances of the one-hour ozone NAAQS in ozone nonattainment and near-nonattainment areas. The commission believes that it is appropriate for those sources which are contributing to the ozone problem to be part of the solution. Consequently, the commission has made no change in response to the comment.

No comments were received on §117.133(1), which exempts utility electric power boilers or stationary gas turbines if the annual heat input does not exceed 2.2 (10^{11}) Btu per year, averaged over the three most recent calendar years. However, it has come to the commission's attention that the proposed exemption was inadvertently limited to permitted units. The exemption is intended to be available to both permitted and grandfathered units, and the commission has revised the rule accordingly.

Austin and Tenaska supported the proposed exemption in §117.133(2) for stationary gas turbines which are used solely to power other units during start-ups; or operate less than 850 hours per year, based on a rolling 12-month average. Tenaska stated that the "850 hours per year" exemption of §117.133(2)(B) should be made more consistent with the federal acid rain rule definitions of 40 CFR 75, such that units that operate no more than an average of 10% of the hours of the year, averaged over three years, and no more than 20% of the hours in a single calendar year would be exempt. Tenaska stated that this flexibility is important considering the seasonal and highly weather dependent operation of units designed to cover peak loads, and that installation of post-combustion controls on infrequently operated units is not cost-effective.

The suggested change would allow at most an average of only 26 more hours of operation per year. The commission agrees that installation of post-combustion controls on infrequently operated units is not cost-effective, and therefore has revised §117.133(2)(B) and §117.143(h) accordingly.

CPS stated that §117.133(2) should include an exemption for auxiliary boilers. CPS commented that the rule proposal preamble stated: "The proposed rule would not apply to auxiliary boilers which are sometimes present at power plants. Auxiliary boilers are much smaller than power boilers, operate rarely, and account for only 0.01% of the power plant emissions in the attainment counties of east and central Texas." CPS noted that the definition of electric power generating system in §117.10 includes auxiliary boilers.

The intent, as noted in the rule proposal preamble, is to exempt auxiliary boilers. Therefore, the commission has revised §117.133(2) to exempt auxiliary boilers.

TCC commented on §117.133 and noted that the rule proposal preamble contained a description of the unit applicability. TCC suggested including these descriptions in §117.133 to clarify the applicability and exemptions.

The commission believes that the rule applicability and exemptions are clear. The commission has made no change in response to the comment.

Tenaska suggested the inclusion of an exemption in §117.133 for "qualifying facilities," which are cogeneration facilities that meet the specific criteria of the FERC and which are not subject to regulation by the PUCT. TCC recommended adding an exemption to §117.133 for non-utility gas turbine cogeneration facilities.

The commission has added a new paragraph (3) to §117.133 which exempts each unit that generates electric energy primarily for internal use but that, averaged over the three most recent calendar years, sold less than one-third of its potential electrical output capacity to a utility power distribution system. This exemption is based upon §116.910(g) of this title (Applicability). In addition, the exemptions of §117.133(1) and (2) are available to small cogenerators who may exceed the one-third limitation.

Bryan, CEED, CPS, CSW, NACC, Reliant, and TXU commented on the format of the NO_x limits in §117.135. Bryan, CEED, CSW, NACC, Reliant, and TXU supported the use of the traditional heat input-based format of lb NO_x/MMBtu rather than the output-based format of lb NO_x/megawatt-hour. CEED and NACC stated that output-based standards discriminate against Texas lignite and coal since these fuels have a higher moisture content (and thus a lower heat rate) which makes achieving the standard more difficult. TXU stated that input-based standards are consistent with all commission and EPA standards (except for the recently adopted New Source Performance Standards (NSPS) for new electric utility steam generating units), as well as CEMS and data management programs for utilities. TXU also stated that it is difficult to make significant efficiency improvements on existing units and expressed the belief that most utilities will choose to use the system cap or the forthcoming emission banking and trading program. CPS stated that the forthcoming emission banking and trading program will make the format of the emission standards a moot point since the focus of such a program will be on tons emitted.

The NO_x standards of §117.135 were proposed in the traditional heat input-based format of lb NO_x/MMBtu, although the commission requested comment on expressing the §117.135 NO_x limits in the output-based format of lb NO_x/megawatt-hour. Output-based standards allow the source owner to improve the efficiency of the regulated equipment. By harmonizing the environmental and economic goals more closely, output-based standards can lower the cost of regulation compared to input-based standards. The numeric value of equivalent output-based emission standards could be calculated readily from electric production records for the baseline emission period. However, because the commission also proposed to allow emission cap compliance, which also permits efficiency improvements to contribute toward rule compliance, and offers even more flexibility, an output-based format would only be useful if a utility were likely to choose the option of direct emission compliance with the standard. The commission did not recommend making a change but solicited comments from the regulated community to allow for constructive feedback and change if the comments indicated support for a change. The commission agrees with the reasoning provided by the commenters. Output-based standards would provide little benefit for existing units and would needlessly complicate the existing

regulatory procedures in place. The commission has retained the proposed traditional heat input-based format of lb NO_x/MMBtu.

ED, LWVTC, Steering Committee, Tulsa, and 515 individuals supported the proposed NO_x emission limits for utility boilers and stationary gas turbines in §117.135. CEED, CPS, CSW, Dallas Sierra Club, LWVTX, NACC, Reliant, Sabine, San Miguel, SCLSC, TMPA, TMRA, TXU, and five individuals opposed the proposed limits. One individual recommended that at least a 90% NO_x reduction be required, SCLSC recommended NO_x reductions of 80%, while Dallas Sierra Club and LWVTX recommended NO_x reductions of 88%. Hall and two individuals recommended that at least an 88% NO_x reduction be required in all 12 counties of the DFW CMSA. Three individuals simply stated that the proposed limits were not stringent enough.

CEED, CSW, NACC, Reliant, and TXU stated that most coal or lignite-fired power plants can not meet the proposed limit of 0.165 lb/MMBtu for coal-fired utility boilers specified in §117.135(1)(B)(ii) and (iii) without post-combustion control. CPS stated that two of its three coal-fired units in Bexar County are "first generation western coal-fired units" which were designed before all the difficulties of firing western low-sulfur coal were known. CPS stated that compared to later designs, these two units have smaller furnace volumes, higher burner zone and volumetric heat release rates, and considerably smaller distances between burners and between the uppermost burner level and the top of the furnace, which CPS stated would make it difficult to achieve the 0.165 lb/MMBtu limit through combustion modifications. Reliant, Sabine, San Miguel, and TMRA suggested a limit of 0.2 lb/MMBtu, which they believed could be met by Texas lignite-fired power plants. CSW and TMPA likewise suggested a limit of 0.2 lb/MMBtu for coal-fired power plants, which they believed is an economically realistic value, while TXU suggested a limit of 0.2 to 0.22 lb/MMBtu for lignite and coal-fired power plants.

Austin stated that its consultants estimate (and equipment vendors have confirmed) that installation of low-NO_x burners at units 1 and 2 of the Sam Seymour power plant will allow these units to just barely meet the 0.165 lb/MMBtu limit. Bryan and LCRA stated that the 0.165 lb/MMBtu limit may be achievable at their coal-fired units through combustion modifications, while TMPA stated that combustion modifications at its coal-fired unit may reduce NO_x emissions to levels quite near the proposed 0.165 lb/MMBtu limit. However, Austin, Bryan, LCRA, and TMPA expressed concern that in practice the units could fall short of meeting the limit and stated that additional flexibility, such as higher limits or a broad trading program, would avert this potential problem. CSW commented that the lowest NO_x rate that its coal-fired EGFs can achieve with combustion modifications is 0.235 lb/MMBtu. Reliant stated that an advanced low-NO_x burner/separated overfire air system being installed in March 2000 at its Limestone Electric Generating Station is guaranteed to achieve a NO_x emission rate of 0.2 lb/MMBtu.

CEED and NACC asserted that SCR technology has never been applied to a coal or lignite-fired power plant, while CSW and TXU asserted that SCR technology has never been applied to a lignite-fired power plant in the United States. CSW also asserted that SCR technology has never been demonstrated to be technically practicable on a powder river basin (PRB) coal or Texas lignite-fired EGF. San Miguel asserted that SCR technology has never been applied to a power plant which is fired on Texas lignite. CEED and TXU also stated that utilities in the United States have had minimal success in retrofitting these controls on coal-fired power plants. CEED and NACC stated that only two United States power plants (one in New Jersey, and one in New Hampshire) have been retrofitted with SCR technology. CSW stated that at least one (unnamed) catalyst vendor is unwilling to guarantee SCR catalyst performance for EGFs that burn PRB coal. CPS asserted that if it were to install SCR at its EGFs in Bexar County, the cost would be borne by a population that has lower income levels and which has a more limited economy than any of the ozone nonattainment areas where most of the ozone reductions resulting from the rules will occur.

CEED stated that a coal-fired power plant in Texas was able to achieve emission levels near the 0.165 lb/MMBtu limit through the use of "advanced low-NO_x burners and sophisticated control technology" but that other units at the same power plant could only reach 0.21 lb/MMBtu using the same technology. TMPA suggested that an alternative emission specification be available for instances in which the installation of aggressive combustion modifications at units subject to the 0.165 lb/MMBtu NO_x limit of §117.135(1)(B)(ii) and (iii) fell short of achieving total compliance.

TXU asserted that SCR is the only post-combustion control available for coal or lignite-fired utility boilers. TXU commented further that SCR performance at coal and lignite-fired boilers is influenced by a number of factors (temperature, fuel sulfur content, ammonia-to-NO_x ratio, NO_x concentration at the SCR inlet, gas flow rate, and catalyst condition). CSW and TXU stated that SCR can cause operational problems, such as plugging of the air heater, poisoning of the catalyst, and corrosion resulting in forced outages. TXU stated that in January 1999, the Electric Power Research Institute

(EPRI) advised that at that time there had been six coal-fired units built with SCR and one retrofit, and that the retrofit unit could not meet the proposed NO_x limit of 0.165 lb/MMBtu.

CEED, CPS, CSW, Reliant, TMPA, and TXU stated that post-combustion controls are extremely expensive. TXU commented that it estimates the cost of retrofitting SCR on a lignite-fired unit to be $60 million to $80 million, with estimated annual operating and maintenance costs of $5 million per year. CSW estimated the cost of retrofitting SCR to be $38 million on one of its coal-fired units and $60 million for one of its lignite-fired units, with estimated annual operating and maintenance costs of $3 million to $5 million per year. San Miguel estimated the cost of retrofitting SCR on its lignite-fired unit to be $8 million to $15 million. Reliant estimated the cost of retrofitting SCR or SNCR on its lignite-fired Limestone Station to be $20 million to $100 million. CSW stated that unlike most other utilities, it would not be able to recover any of its stranded environmental costs for four of its five coal-fired EGFs in east and central Texas. CEED, CSW, San Miguel, TMPA, and TXU asserted that the cost rises significantly to meet the proposed NO_x limit of 0.165 lb/MMBtu instead of a limit of 0.2 lb/MMBtu due to the need for SCR rather than combustion modifications.

There appears to be a misconception on the part of a number of commenters that SCR is the only post-combustion control option available to them. In fact, SCR is merely one of several post-combustion control options for reducing NO_x emissions on an EGF, with other options including but not limited to SNCR and SNCR/SCR hybrid systems (in which SNCR is followed by a smaller SCR system). Other options for reducing NO_x emissions include low-NO_x burners, low excess air

operation, staged combustion (for example, overfire air), flue gas recirculation (FGR), and fuel-lean and conventional (fuel-rich) reburn.

***Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers* (June 1998), prepared for Northeast States for Coordinated Air Use Management (NESCAUM) and Mid-Atlantic Regional Air Management Association (MARAMA), included case studies of various utility boilers which were controlled with various technologies, including SCR, SNCR, gas reburn, and gas-fired low-NO_x combustion modifications. The utility boiler operators cooperated by providing actual project cost, operating cost, as well as operating experience. Because the actual cost information for completed projects was available and was provided directly by the operators, the cost analysis is "anchored in reality" rather than being mere speculation. Of the 11 Group 1 coal-fired utility boilers in the case studies, five were equipped with SCR, five were equipped with SNCR, and one was equipped with gas reburn. Because the NESCAUM/MARAMA report was issued nearly two years ago, additional coal-fired boilers undoubtedly have been, or are in the process of being, equipped with post-combustion controls. In any event, it is clear that multiple coal-fired utility boilers have been equipped with post-combustion controls. Of the ten Group 1 coal-fired utility boilers with SCR or SNCR, there were a total of three forced outages (all in the initial months of operation at the first electric utility boiler SNCR system) after a total of 230 boiler-months of operation. The NESCAUM/MARAMA report concluded that "the experience with these technologies has been extremely positive. While each project had its challenges, the overall reliability and performance of the secondary control technologies has been extremely good. Technology suppliers appear to have addressed the concerns that have been expressed by the**

utility industry regarding difficulties in applying these technologies to commercial U.S. facilities and any impact to facility reliability." For coal-fired utility boilers, capital costs for SCR and SNCR were found to be $50/kW - $70/kW and $15/kW, respectively, for the scenarios most similar to the units in east and central Texas. Since lignite is simply coal with a lower Btu value, there is no reason to expect costs for control of lignite-fired units to vary significantly from that of coal-fired units. Some of the commenters' capital cost estimates for SCR appear to be higher than the actual experience has shown. The commenters did not provide detailed cost estimates or vendor quotes to document their reported cost estimates. It should also be noted that SNCR is available at a capital cost approximately 20-30% that of SCR. There are 30 commercially operating SNCR systems under one vendor's trade name on utility boilers, most of which are tangentially-fired. The NO_x reductions from these systems range from 32% to 55%, with a typical reduction of 35-40%. Fuel type is not an issue with SNCR; this technology puts urea reagent in the furnace above the combustion zone, and getting the reagent to find the NO_x does not depend on ash properties. For NO_x control, a lignite-fired utility boiler is easier to control than the average coal-fired boiler, since the big furnace volumes, low fuel heating values, and tangential firing are all favorable to NO_x control. In addition, the NESCAUM/MARAMA report noted that "hybrid SCR/SNCR is one technology that has been demonstrated at some facilities to provide high levels of NO_x reduction at congested sites where a full SCR system may be very expensive."

The system cap of §117.138 provides flexibility for finding cost-effective emission reductions. In addition, the commission expects that the forthcoming rules for an emissions banking and trading program will provide a way to address a situation in which combustion modifications to a unit left

it just over the emission rate allowable. As discussed earlier, the emissions banking and trading program is also expected to reduce the cost.

There are two strategies for NO_x emission reductions from EGFs. SB 7 is a strategy for reductions from grandfathered EGFs. Separate and apart from SB 7, this Chapter 117 rulemaking is designed to achieve NO_x emission reductions from EGFs as part of the strategy for reaching attainment with the ozone NAAQS in DFW. In order to avoid the inequity associated with a more stringent emission limit (0.14 lb/MMBtu) for grandfathered EGFs than for permitted EGFs (0.165 lb/MMBtu), the commission has revised §117.135(1)(B) to specify an emission limit of 0.165 lb/MMBtu for coal-fired EGFs. However, grandfathered EGFs which use coal (including lignite) as a fuel will also be subject to the SB 7 reduction requirements in Chapters 101, concerning General Air Quality Rules, and 116, concerning Control of Air Pollution by Permits for New Construction or Modification (see the January 7, 2000 issue of the *Texas Register* (25 TexReg 128)). The change to the language in §117.135(1)(B) simply allows units which are subject to SB 7 to count their reductions toward the system cap set out in §117.138.

Regarding the comments that the NO_x emission limits for utility boilers and stationary gas turbines in east and central Texas are not stringent enough, the commission disagrees. The adopted DFW SIP and individual enforceable rule measures necessary to make it approvable required a careful balancing of many factors. The commission's focus has been on the goal of developing a credible plan to attain the one-hour ozone standard. The commission believes that the adopted SIP realistically may solve a pollution problem that to date has proved to be virtually

unsolvable in the largest urban areas in the country. The plan is certainly based fundamentally on quantitative analysis, much of which is dictated by the EPA. The current models demonstrate the difficulty of attaining the ozone standard. Air emissions derive from most sectors of human activity, and the required reductions are large enough to require reductions from all sectors. The uncertainties involved in the vast amount of numerical analysis also introduce the need for qualitative assessments of the plan. An important insight from the model is that the benefits of reductions do not accrue linearly. When a certain threshold level is achieved, the model response improves, so that a ton of NO_x reduced produces more ozone reduction than a ton of reduction when the overall reduction is less. This response indicates that plans which rely too much on marginal analyses to demonstrate attainment are more likely to fail.

The adopted SIP contains 13 measures which as a whole are projected to bring DFW back into attainment. Each measure varies in terms of costs, social impact, and ozone benefit. The regional electric utility rule is an attractive measure compared to the other measures because of its low social impact. Other measures affect far greater numbers of much smaller sources and are more difficult to implement from this standpoint.

CSW and TXU stated that SCR technology results in ammonia emissions from ammonia "slip" (i.e., ammonia which did not react completely with the combustion gases and instead is emitted from the unit) and that ammonia also contaminates the fly ash, which then must be treated as a hazardous substance under the Comprehensive Environmental Response, Liability, and Compensation Act, §42, USC §§9601 et seq. (CERCLA), rather than being recycled. CSW and TXU expressed concerns about safety of transportation, storage, and handling of ammonia required for SCR, as well as the disposal of spent catalyst. CSW and TXU stated further that the use of SCR decreases the efficiency of the unit in which it is used because booster fans are required to overcome the pressure drop created by the SCR system.

Minimizing ammonia slip depends on designing the system such that injected ammonia is properly-mixed and well-distributed and such that the amount of catalyst is sufficient to control both NO_x and ammonia to the desired levels. An EPA study (*Applications of Selective Catalytic Reduction Technology on Coal-Fired Utility Boilers*, 1997) examined 14 coal-fired units for which ammonia slip data were available. Ammonia slip at seven of the units was in the 0.1 to 1.0 ppmv range, and ammonia slip at the remaining seven units was below 5.0 ppmv. Thus, with good design, SCR can achieve ammonia slip values well below 5.0 ppmv. Similarly, for SNCR the ammonia slip is addressed through good design (particularly, improved operating control using better signal inputs on boiler temperatures, which is now real-time optical sensing). Indeed, an SNCR vendor guarantees ammonia concentrations of no more than 5.0 ppmv ahead of the air preheater, which is a more challenging limit than an in-stack limit).

The Resource Conservation and Recovery Act (RCRA) was established in 1976. It gave the EPA authority to regulate hazardous waste from generation to disposal, including transportation, treatment, storage, and ultimate disposal. CERCLA refers to the "Superfund" program, whose mission is to remediate abandoned or inactive sites that pose an unacceptable risk to public health and safety or the environment. Consequently, RCRA appears to be the appropriate federal

requirement of concern. According to the EPA, fly ash from electric utility boilers is exempt under RCRA. While there is little data from SCR or SNCR units on the relationship between ammonia slip and adsorption of ammonia in fly ash, there is no evidence that ammonia slip rates below 5.0 ppmv affect the marketability of fly ash. In fact, ammonia in the fly ash is not preventing utilities in the eastern United States from selling fly ash to cement manufacturers for use in cement kilns, with typical values of 60-100 ppm in electrostatic precipitator ash. From a chemical standpoint, the more alkaline Texas lignite would result in lower ammonia adsorption on the fly ash as compared to eastern coals.

Various safety programs such as the Accidental Chemical Release Risk Management Program will minimize risks associated with the transportation, storage, and handling of ammonia. Most of the safety concerns related to anhydrous ammonia can be avoided through the use of aqueous ammonia, which has concentrations of less than 30% ammonia in water, or urea, which is noncombustible. Urea can be shipped either as a solid or as a liquid solution in water. Processes are available which convert urea into ammonia on-site as needed, which avoids whatever risks may be associated with the transportation, storage, and handling of ammonia. Regarding SCR's reported effect on boiler efficiency, the commenters did not provide details about the efficiency difference. However, the NESCAUM/MARAMA report indicated a 0.5% loss in heat rate with SCR, SNCR, and SNCR/SCR hybrid systems. The commission considers this to be minor in light of the associated NO_x reductions.

CPS stated that the limits in §117.135 which apply to grandfathered EGFs should be deleted because setting limits for these units contradicts 30 TAC §101.333 (Allocation of Allowances). CPS stated that the Chapter 101 and 116 rules which enforce the SB 7 requirements tie the emission limit to the 1997 rate and cap the emission tons for the unit, and do not impose an emission limit. CPS stated that the proposed inclusion of grandfathered EGFs makes the trading program meaningless because the grandfathered gas-fired units will now have to meet an emission rate restriction, rather than allowing the flexibility to achieve compliance by trading. CPS stated further that there will be no incentive to opt-in permitted, electing units to the trading program if emission rates are specified for all gas-fired units.

As described elsewhere in this preamble, the commission has revised the system cap of §117.138 to facilitate trading within an electric power generating system until the forthcoming emission banking and trading program is finalized. The commission expects that the forthcoming banking and trading program will lower the cost of compliance and ultimately will be the preferred compliance option for affected EGFs because such a program will allow overcontrol of the more cost-effective units to be applied to units which are less cost-effective. The commission has made no change in response to the comment.

CPS also suggested that a NO_x emission reduction requirement of 30% (approximately 0.23 lb/MMBtu) be specified for EGFs in Atascosa and Bexar Counties, and possibly Fayette and Goliad Counties as well. CPS asserted that EGFs in these counties do not contribute significantly to the overall regional ozone problem because extensive aircraft investigations have demonstrated that transport to the nonattainment counties generally does not originate from these counties, or that transport distances for the nonattainment areas are too short to be materially affected by emissions from an area roughly described as the triangular area formed by connecting the cities of Austin, San Antonio, and Corpus Christi. CPS asserted that EGFs in these counties (Atascosa, Bexar, Fayette, and Goliad) should therefore not be regulated under the proposed rules. CPS also asserted that aircraft flights in the San Antonio area demonstrate that the upper air conditions of Bexar County are usually VOC-limited, meaning that elevated point source emissions in Bexar County actually reduce upper air ozone levels in that county. However, CPS stated that this beneficial impact is somewhat diminished by the further finding that the plume centerlines of San Antonio's urban ozone plume and the elevated power plant plume from southeastern Bexar County do not coincide. CPS stated that this leads to the conclusion that while emissions from sources outside Bexar County have a great impact on San Antonio's ozone attainment status, the sources within Bexar County do have not near as great an impact on the nonattainment or near-nonattainment areas in northeast Texas.

CPS stated that modeling conducted by the Alamo Area Council of Governments demonstrates that Bexar County point sources contribute only about 2.0% of the ozone in San Antonio while 60% is imported from outside San Antonio. CPS asserted that this demonstrates that power plant emissions in Bexar County have a minimal effect on San Antonio's ozone levels, while transport of emissions into Bexar County have a significant impact on San Antonio. CPS stated that modeling demonstrates that emission reductions resulting from the proposed rulemaking will reduce ozone levels in northeast Texas by an average of 12.6 ppb but an average of only 2.4 ppb in San Antonio. CPS suggested that as a result it was inequitable for sources in the southwestern portion of the eastern half of Texas to be subject to the same control levels and costs as sources in the northeast portion of the eastern half of Texas. CPS also stated that high ozone levels, including exceedances of the ozone NAAQS, have occurred in San Antonio while one or more of the CPS coal-fired EGFs were off-line or operating at reduced levels which approach or exceed the goal of a 50% NO_x reduction.

The commission is not aware of any "extensive aircraft investigations" performed in this triangular area, but would be interested in viewing any scientific data or studies collected by stakeholders. Without missions being flown on a continuous basis, one cannot say that these counties do not *generally* contribute to regional ozone; one or two investigations cannot form the basis for such a broad conclusion. A recent analysis of missions flown on behalf of the commission in the San Antonio area suggests that, on average, only about 40% of the peak ozone concentration in San Antonio is produced locally, which in turn suggests that regional ozone levels play a crucial role in San Antonio.

This analysis also showed that rural point sources can make significant contributions to background ozone levels which can then make their way to urban areas. Furthermore, this analysis found that air parcel trajectories frequently recirculate through an area and that air pollutants can therefore linger in that area for up to two days. This allows ample time for ozone levels to build up in an urban or rural level even if the direct distance between rural sources and urban areas is relatively short. Even if transport distances from the counties in this triangle were too short for significant ozone to form, ozone precursors would still exist in abundance and would be able to react with other precursors created in the urban area.

The modeling performed by the Alamo Area Council of Governments is one episode with Urban Airshed Model version IV (UAMIV) modeling. This modeling has been revised with the more appropriate CAMx model used by the commission for SIP development and regional scale modeling. The episode was not selected to evaluate the impact of the CPS sources on the air quality in San Antonio. Extensive sensitivity modeling with the UAMIV developed episode has not been performed, and the work performed has not been documented or reviewed by the commission. Therefore, the accuracy or appropriateness of the comments of the impact of the CPS sources can not be verified. If this model has been exercised to provide analysis of transport, the results have not been presented or documented, so it is not possible to verify the accuracy or appropriateness of the comments relating to transport into the San Antonio area. An ozone reduction of 2.4 ppb is a very significant reduction when considering the relative impacts found during analysis of control strategies for the DFW and HGA SIP modeling.

CSW, NACC, and TXU commented on the limit of 0.165 lb/MMBtu for coal-fired utility boilers proposed in §117.135(1)(B)(ii) and (iii) as it relates to ozone levels. CSW and TXU stated that this limit is more stringent than necessary to achieve and maintain compliance with the ozone standard in Longview and Tyler. TXU stated that modeling conducted by Environ on behalf of the East Texas Council of Governments (ETCOG) and North East Texas Air Care (NETAC) shows that a NO_x limit of 0.20 to 0.22 lb/MMBtu (a 35% to 40% reduction) at electric utilities in east Texas would eliminate all ozone exceedances in Longview and Tyler with a margin of safety of nearly 6 ppb. CSW stated that modeling conducted by Environ on behalf of the ETCOG and NETAC shows that a NO_x limit of even higher than 0.20 lb/MMBtu at electric utilities in east Texas would strengthen the previous demonstration that Longview and Tyler will remain in attainment with the one-hour ozone NAAQS.

The commission concurs with the description of the modeling results mentioned in the comment. However, based on the regional analyses cited in the proposal, the commission concluded that reducing regional power plant emissions by 50% (corresponding to a 0.165 lb/MMBtu limit for coal-fired units) would be sufficient to make a significant reduction in ozone and ozone precursor levels transported into the state's nonattainment areas. This level of control was therefore assumed in the DFW control strategy modeling. Even assuming these regional reductions, severe controls are required in the DFW area to demonstrate attainment of the ozone NAAQS. By reducing the level of regional control, even greater reductions would be required in the nonattainment counties to demonstrate attainment. Consequently, the regional NO_x emission reductions resulting from the proposed limit of 0.165 lb/MMBtu for coal-fired utility boilers are crucial for DFW to attain the ozone NAAQS.

TXU asserted that the difference between the proposed limit of 0.165 lb/MMBtu and a limit of 0.2 lb/MMBtu would be less than 0.1% on peak ozone concentrations in DFW. CSW stated that modeling by Environ shows that the difference between the proposed limit of 0.165 lb/MMBtu and a limit of 0.2 lb/MMBtu would be only about 0.1 ppb on ozone concentrations in DFW. NACC stated that modeling by Environ shows that the difference between the proposed NO_x limit of 0.165 lb/MMBtu and a limit of 0.2 lb/MMBtu on peak ozone concentrations in DFW would be 0.1 to 0.2 ppb and that reducing power plant emissions by 50% will have less than a five ppb impact on DFW. NACC further stated that according to the commission this reduction is within the margin of error of the model. CSW asserted that the Environ modeling demonstrates that the difference between the proposed limit of 0.165 lb/MMBtu and a limit of 0.235 lb/MMBtu would be a reduction of 0.1 to 0.3 ppb in ozone concentrations in DFW. TXU asserted that the Environ modeling demonstrates that there is minimal difference in air quality impacts between the proposed NO_x limit of 0.165 lb/MMBtu and a limit of 0.2 lb/MMBtu, and therefore no justification for the 0.165 lb/MMBtu limit based on any claim of benefit to the DFW area. Similarly, TXU asserted that for Austin and San Antonio the commission has not demonstrated that the proposed NO_x limit of 0.165 lb/MMBtu would provide significantly more benefit than a limit of 0.20 to 0.22 lb/MMBtu. TXU also stated that the one-hour ozone concentrations for Austin and San Antonio are currently below the one-hour ozone NAAQS.

The commission agrees that no analysis was done to determine the specific contribution of a 0.165 lb/MMBtu limit or other alternative control levels applied on distant power plants. However, based on the regional analyses cited in the proposal, the commission concluded that reducing regional power plant emissions by 50% (corresponding to a 0.165 lb/MMBtu limit for coal-fired units) would be sufficient to make a significant reduction in ozone and ozone precursor levels transported into the state's nonattainment areas. This level of control was therefore assumed in the DFW control strategy modeling. Even assuming these regional reductions, severe controls are required in the DFW area to demonstrate attainment of the ozone NAAQS. By reducing the level of regional control, even greater reductions would be required in the nonattainment counties to demonstrate attainment.

The particular episodes modeled were not chosen to demonstrate the effectiveness of regional power plant controls, and should not be expected to do so. The commission would like to model additional episodes, but time and budget restrictions prevented doing so for these particular SIP revisions. The commission agrees that the modeling's margin of error is greater than five ppb when comparing peak ozone predictions to monitored ambient concentrations. However, in this instance the modeling is used to estimate the change in ozone concentrations as a result of applying controls. In this case, the margin of error is generally considered to be well below five ppb. The commission agrees with the commenters' interpretation of Environ's results but cannot confirm or refute the modeling itself since it has not performed a thorough peer review. In any case, for an area on the borderline of nonattainment, an increase in ozone of 0.2 ppb could easily be enough to throw the area into nonattainment.

NACC commented that local facilities have a greater impact on air quality than more distant facilities.

The commission agrees that local facilities have a greater impact on air quality than more distant facilities. However, emissions from distant facilities are frequently significant. Analysis of continuous air monitoring station (CAMS) monitoring data for the DFW area shows that regional sources contributed to all but three of the 78 exceedances of the one-hour ozone NAAQS since 1990. On the average, local urban sources caused the formation of 63 ppb of ozone, while the more distant regional sources caused only 35 ppb. While the urban contribution is clearly larger, both are significant and must be controlled in order to attain the one-hour ozone NAAQS.

NACC commented that the commission is asking Texas ratepayers to spend hundreds of millions of dollars to reduce emissions that contribute only 2.3% of the total ozone precursor emissions.

The commission agrees that 2.3% of total ozone precursors is technically correct, but irrelevant. Because it compares coal-fired power plant NO_x emissions to the total of all biogenic and anthropogenic emissions of VOC and NO_x for the entire 110-county East Texas area (including the DFW, HGA, and BPA nonattainment areas), it results in a very small number. However, the control strategy is based primarily on NO_x emissions, and coal-fired power plants emit approximately 20% of the NO_x in that same area.

The incremental production cost should not exceed $2.00 per megawatt hour for controls, which assuming a retail price of $.10 per kilowatt hour, would be a 2.0% increase.

CSW questioned why the commission did not pursue further NO_x reductions from sources in the DFW, BPA, and HGA ozone nonattainment areas before proposing NO_x reductions for permitted coal-fired EGFs located in areas that are currently meeting the one-hour ozone standard. CSW stated that the proposed NO_x limits for permitted coal-fired EGFs in areas that are currently meeting the one-hour ozone standard must be based on a much stronger and more sound technical and scientific basis than would be necessary if that same NO_x limit were proposed to be applied in the DFW, BPA, and HGA ozone nonattainment areas.

As noted earlier, the commission is pursuing emission reductions from a variety of sources in the ozone nonattainment areas, as well as in the ozone attainment counties of east and central Texas, and it is likely that additional emission reductions will be necessary in the future. It should also be noted that the emission limitations for EGFs in ozone nonattainment counties are significantly more stringent than those for EGFs in the ozone attainment counties of east and central Texas. For example, EGFs within the DFW ozone nonattainment area are being required to reduce NO_x emissions by approximately 88% as opposed to the estimated 50% reduction required of similar facilities in attainment and near-nonattainment counties.

CSW stated further that the EPA's Acid Rain Database shows EGFs in Texas as having some of the lowest NO_x emission rates in the United States. CSW also stated that when the SB 7 NO_x emission reductions are achieved, the average NO_x for EGFs in Texas will be less than the average NO_x emission rates for EGFs in 43 of the other states, while TMRA stated that the average NO_x emission rate for EGFs in Texas is lower than the average NO_x emission rates for EGFs in 47 of the other states and that these rates will continue to decline as the SB 7 NO_x emission reductions are achieved. TXU stated that when the SB 7 NO_x emission reductions are achieved, the average NO_x emission rate for EGFs in Texas will be less than the average NO_x emission rates for EGFs in 45 of the other states, according to the EPA's Acid Rain Database. TXU also stated that the average NO_x for EGFs in Texas is 40% lower than the national average NO_x emission rate for EGFs.

While EGFs in Texas have a lower emission rate than the national average on a lb/MMBtu basis, ozone formation results from reactions of ozone precursors in the presence of sunlight. It is the

mass emission rate of ozone precursors that is of relevance, rather than the NO_x emission rate on a lb/MMBtu basis. In addition, there are many high-NO_x baseline coal-fired EGFs in the Midwest which raise the national average NO_x emission rate. Consequently, the average lb/MMBtu emission rate for EGFs is not the appropriate basis for a comparison of Texas to other states, many of which do not even have any ozone nonattainment areas.

CSW and TXU asserted that the commission's choice of a NO_x emission reduction goal of 50%, rather than another percentage, for the proposed NO_x emission limit for permitted coal-fired EGFs is without any technical or scientific justification. CSW stated that the commission's choice of a 50% emissions reduction goal was based primarily on the fact that SB 7 is anticipated to result in a 50% reduction in NO_x emissions from grandfathered EGFs, and that SB 7's goal has no technical or scientific basis but instead was merely a negotiated, politically-drive decision. TXU expressed the belief that combustion modifications at EGFs in east and central Texas, in conjunction with the reductions required by SB 7 and anticipated to be required in BPA, DFW, and HGA, would approach an overall reduction of more than 55% from EGFs in east and central Texas.

The commission disagrees with the commenters. As noted earlier in this preamble, modeling tests indicate that point source NO_x reductions of less than 50% have limited ozone reduction benefit, whereas reductions at and above 50% show increasing ozone reduction benefits. For example, in the DFW area, 25% NO_x reductions in all attainment counties of east and central Texas result in a seven to ten ppb one-hour ozone reduction, whereas 50% NO_x reductions over the same area result in a 21-27 ppb one-hour ozone reduction. Doubling the NO_x reduction from 25% to 50% provides

more than twice the ozone reduction benefit. The commission's choice of a 50% emissions reduction goal was based on this fact. TXU did not provide an analysis to support their contention that combustion modifications at EGFs in east and central Texas, in conjunction with the reductions required by SB 7 and anticipated to be required in BPA, DFW, and HGA, would approach an overall reduction of more than 55% from EGFs in east and central Texas.

CSW asserted that the Baylor aircraft monitoring does not support the proposed 50% reduction in NO_x emissions from coal-fired EGFs due to a variety of limitations in the data. Specifically, CSW stated that the monitoring data only represent a snap-shot in time of the concentrations of ozone, NO_x, and other air contaminants and do not demonstrate or indicate what the concentrations would be at a later time or day. CSW also stated that the data only represent a snap-shot in space of the concentrations of ozone, NO_x, and other air contaminants and do not demonstrate what the concentrations would be at a different altitude or at different locations at the same altitude. CSW further commented that the relevant altitude for modeling and monitoring attainment with the one-hour ozone NAAQS is ground level, that the Baylor aircraft monitoring data was generally collected at 800 feet to 10,500 feet, and that the commission has not presented information or data to support a conclusion that the one-hour concentration at a ground level location would be the same as the concentration measured by aircraft at a much higher altitude directly above the ground level location. CSW also stated that meteorological conditions (e.g., wind speed and direction) associated with the aircraft monitoring were not always known or were so variable as to limit or eliminate the value of the data for the proposed NO_x emission limits. Finally, CSW stated that the aircraft monitoring data do not indicate or demonstrate whether or by how much the proposed NO_x emission reductions will decrease one-hour ozone concentrations in ozone nonattainment areas to allow a demonstration of attainment with the one-hour ozone NAAQS in or near-nonattainment areas to help them avoid being designated as one-hour ozone nonattainment areas.

Comparison of ground monitoring data with airborne pollutant levels suggests that airborne data compares relatively well to ground-based data. Baylor aircraft flights are planned so the aircraft is being flown at a time and an altitude in which the atmosphere is mixed. In these conditions, pollutant levels can usually be assumed to be fairly uniform from ground height all the way up to the "mixing layer." Also, the aircraft usually performs more than one up-and-down spiral precisely for the purpose of measuring how pollutant levels change in the vertical. Consequently, any changes in pollutant levels can be identified and taken into account.

While it is true that a given pollutant measurement point is only a "snap-shot in time," the same could be said for any single measurement point at ground monitoring site. Baylor University's airborne monitoring platform has several capabilities which allow it to overcome this "limitation." First, the Baylor aircraft can, and does, fly over the same latitude and longitude coordinates more than once in a given flight which means that it has the ability to measure pollutants at a single point over time. Second, because the aircraft moves, it can, and does, track a particular "parcel" of air throughout the day as it moves through a geographic area and disperses. Third, because the aircraft can climb and descend, it can, and does, measure vertical changes in pollutant levels. Additionally, the aircraft is often flown during a time of the day when the atmosphere is relatively well-mixed so that differences with ground-based monitors can be further minimized.

Even though having wind data collected by the aircraft during its flight is the preferred mode of operation, the inability to do so does not prevent the Baylor aircraft from providing important information. Additional resources, such as ground monitoring data, meteorological models, and radar data can provide important wind information needed to interpret flight data.

Tenaska commented on the proposed limit of 0.15 lb/MMBtu for stationary gas turbines specified in §117.135(2)(B) and (C). Tenaska noted that this limit is approximately equivalent to 42 ppmv NO_x and suggested that the rule specify an alternate limit of 42 ppmv NO_x, adjusted to 15% oxygen. Tenaska stated that this would avoid unintended impacts on facilities that lack systems and guarantees to demonstrate compliance with the proposed limits in lb/MMBtu. Tenaska also stated that even the latest combustion technology can not achieve lower than 42 ppmv NO_x emissions while firing fuel oil without post-combustion controls.

The commission has revised §117.135(2)(B) and (C) to specify an alternate limit of 42 ppmv NO_x, adjusted to 15% oxygen. Regarding the comment about fuel oil firing, the commission notes that natural gas enjoys a significant cost advantage over fuel oil on a cost-per-heating-value basis, and this economic difference will generally discourage the use of fuel oil. While some minimal fuel oil firing may still occur (for example, to ensure reliability of fuel oil backup systems), the emission limits of §117.135 are on an annual (calendar year) basis. The commission expects that this averaging period will easily allow occasional firing of fuel oil without jeopardizing compliance with the emission limits.

Brazos, Bryan, CSW, EPA, Reliant, San Miguel, Tenaska, TPPA/ED, and TXU commented on the proposed optional system cap of §117.138, which provides a flexible alternative to direct compliance with the NO_x emission specifications of §117.135. Brazos, Reliant, TPPA/ED, and TXU noted that the system cap does not allow inter-company trading. Brazos, TPPA/ED, and TXU stated that the cost of compliance for EGFs will be higher than estimated in the rule proposal preamble because the commission did not concurrently propose a regional NO_x trading program.

Bryan stated that TMPA, of which Bryan is a part, operates a single coal-fired unit, while Brazos and San Miguel stated that San Miguel operates a single lignite-fired unit. Reliant stated that they only have two units (at the Limestone Station) with which to average under a system cap. Brazos, Bryan, and San Miguel commented that without the ability to trade with other companies, they will not be able to use the system cap. Tenaska stated that the proposed system cap is unworkable for its units because the baseline heat input will be below the summer rated capacity heat input, although they are contractually obligated to supply the summer rated capacity heat input when called upon by the customer.

Brazos, CPS, CSW, the EPA, Tenaska, and TXU commented specifically on §117.138(c)(1), concerning the rolling 30-day average emission cap. The EPA stated that the baseline period for the historical heat input should match the commission staff's modeling period. TXU recommended that the highest annual heat input for 1997, 1998, and 1999 be used for allowance calculation using the EPA's Acid Rain Database, while CPS commented that 30 TAC Chapter 101, Subchapter H, Division 2 (Emissions Banking and Trading of Allowances) sets a yearly tonnage rate based on 1997 emissions for EGFs and electing EGFs. Reliant expressed support for the use of data from 1996-1998 and stated that data from later years (i.e., 1999) begin to include the effect of ongoing emission reduction work, lowering the baseline and penalizing companies who have been proactive in emission reduction activities. Brazos stated that the peak period for electric utilities has historically been the months of June, July, August, and September and for this reason suggested that the historic high heat input should be changed to these four months rather than July, August, and September. CSW recommended use of an annual average for consistency with the proposed annual average emission limits of §117.135.

Tenaska stated that the proposed rolling 30-day average would pose serious limitations on the use of fuel oil during winter months. Tenaska stated that since fuel oil usage is likely to occur only during extreme winter cold periods, the rolling 30-day average cap should not apply on a year-round basis. Tenaska suggested that the system cap be for the summer ozone season of May through September, and should be based on the potential heat input, not baseline values. CPS, CSW, and TXU stated that a rolling 30-day average is inconsistent with the cap and trade provisions of SB 7, and TXU also commented that the added complexity of a rolling 30-day average is not justified since the rule applies to ozone attainment counties. CSW commented that a rolling 30-day average emission cap would require greater than a 50% NO_x emission reduction and therefore, is unnecessary to reach the 50% NO_x emission reduction goal.

TXU stated that almost all of the permitted power plants in east Texas are coal or lignite-fired base-load units that operate continuously, and suggested that an annual average is appropriate for these units. TXU also stated that there will be no excess allowances available for trading due to the low emission limits of §117.135, which they believed conflicts with the intent of the trading program designed by the Texas Legislature in SB 7.

The commission believes that the cost estimates for EGFs included in the rule proposal preamble are reasonable. The commission agrees that the forthcoming banking and trading program will lower the cost of compliance and expects that ultimately it will be the preferred compliance option for affected EGFs because such a program will allow overcontrol of the more cost-effective units to be applied to units which are less cost-effective, even between companies. The commission has revised the system cap of §117.138 by changing from 30-day rolling average and daily emission caps to an annual average (based on the total annual heat input for each unit in the emission cap for 1996, 1997, and 1998) in order to facilitate trading within an electric power generating system until the forthcoming emission banking and trading program is finalized. The commission selected the 1996-1998 timeframe because it is the same timeframe used for EGFs in the modeling.

LCRA and TXU commented on §117.138(e), which provides procedures for substituting emissions data during periods when a NO_x monitor is off-line. LCRA and TXU suggested that the data substitution procedures for determining NO_x emissions be consistent with the data substitution procedures of 40 CFR 75, Part D. LCRA stated that this would result in the same NO_x emission rate data being reported to the commission for the Chapter 117 rule and to the EPA for the acid rain program. LCRA also stated that this would eliminate the need for maintaining two NO_x emissions databases and avoid having to make changes to software programs in existing data acquisition and handling systems.

The commission agrees that the suggested changes will minimize costs while also ensuring that adequate substitute emissions data is reported for periods when a NO_x monitor is off-line. Therefore, the commission has revised §117.138(e) accordingly.

Reliant commented on §117.138(g), which requires the owner or operator of any unit subject to a system cap to report exceedances of the system cap emission limit. Reliant stated that the 48-hour report deadline and the 21-day report requirement are unreasonable and commented that the upset and maintenance reporting requirements of 30 TAC Chapter 101, §101.6 (Upset Reporting and Recordkeeping Requirements) and (Maintenance, Start-up and Shutdown Reporting, Recordkeeping, and Operational Requirements), exempt boilers and gas turbines equipped with CEMS from requirements for immediate reporting and creating records. Reliant suggested that the reporting requirements of §117.149 are adequate to ensure that any system cap exceedances are addressed.

The specified exemptions from the upset and maintenance reporting requirements of §101.6 would not apply to exceedances which occurred for other reasons, such as failure to properly maintain control equipment or simply a failure to comply with the system cap emission limit. However, because the commission has revised the system cap of §117.138 to an annual average basis and, as described later in this preamble, has changed the reporting period of §117.149(d) to an annual calendar year basis, the commission agrees that the 48-hour and 21-day report requirements are no longer necessary. The commission has revised §117.138(g) accordingly.

The EPA commented on §117.138(i) and stated that units which are permanently retired or decomissioned and rendered inoperable should be eligible for inclusion in the system cap emission limit only if the shutdown occurred after the modeled emission inventory. Shutdowns that occurred before could only be used to generate credit if the previous shutdowns were carried as existing emissions in the most recent inventory relied on for the rate of progress plan or the attainment demonstration SIP.

The commission agrees and has revised §117.138(i) to specify that a shutdown is creditable only if it occurred on or after January 1, 1999. This date was selected because it is consistent with the 1996-1998 modeling period and because the baseline period for H_i, the historical heat input used in the annual average of §117.138(c)(1), is 1996, 1997, and 1998.

Reliant commented on §117.138(j), which states that emission reductions from shutdowns or curtailments which have been used for netting or offset purposes under the requirements of Chapter 116 of this title may not be included in the baseline for establishing the system cap. Reliant stated that this requirement is unnecessary.

The commission believes that it is appropriate to clearly specify that emission reductions from shutdowns or curtailments which have been used for netting or offset purposes under the requirements of Chapter 116 may not be included in the baseline for establishing the system cap. This is necessary to ensure that no double-counting of emission reductions occurs. The commission has made no change in response to the comment.

CEED and NACC commented on §117.138(k) and stated that startups, shutdowns, and upsets should not be included in the system cap. CEED and NACC stated that the system cap is impractical if startups, shutdowns, and upsets are included.

Consistent with how this issue has been addressed in previous rulemaking, the commission believes that inclusion of startups, shutdowns, and upsets in the system cap is necessary to provide an incentive for owners or operators to minimize emissions from these events. The commission has made no change in response to the comment.

The proposed §117.138(k) includes a maximum daily rate data fill-in procedure which allows an owner or operator to show to the satisfaction of the executive director that the actual emissions were less than maximum emissions. To address concerns expressed by the EPA about the corresponding language in §117.108(k), concerning System Cap, (specifically, what replicable procedure will be used to determine whether actual emissions were less than maximum emissions), the commission has revised §117.138(k) to specify that satisfaction of both EPA and the executive director is necessary.

TXU suggested the addition of a new subsection (l) to §117.138 which would specify that units eligible to be included in a system cap that are subsequently sold to a new owner or operator may continue to operate under the system cap if the former and new owners enter into a contract agreement to meet all requirements of the system cap and operate the units with combined NO_x emissions in compliance with the original system cap. TXU stated that this is necessary so that construction of NO_x controls on units they plan to sell can be maintained for completion by the compliance date specified in §117.512.

The commission believes that the inclusion of two separate owners in a single utility cap is unnecessary. The commission expects that the compliance flexibility that the commenter seeks will be available through use of the forthcoming banking and trading rules. The suggested alternative makes it more difficult for the commission to determine compliance because correcting problems is more complicated when there are two entities responsible. The commission has no control over any contract between utilities. The commission has made no change in response to the comment.

CSW suggested that the proposed §117.141(d)(2) be deleted as part of its request that the basis of the system cap of §117.138 be changed to an annual average.

The commission agrees and has made the suggested revision and renumbered the proposed §117.141(d)(1) as §117.141(d).

An individual commented on §117.143 and opposed allowing PEMS as an alternative to CEMS for NO_x monitoring. The individual expressed concern that PEMS are not accurate enough and do not reflect actual emissions.

The former Texas Air Control Board (TACB) authorized PEMS as an alternative to CEMS, because it offered the possibility of equivalent accuracy and lower costs compared to CEMS, and an opportunity to reduce emissions. After more operating experience has been achieved with PEMS, an evaluation of its ability to consistently track NO_x emissions over time will be needed. The commission has made no change in response to the comment.

CPS and TXU stated that §117.143(b), which requires CO monitoring, should be deleted since there is not a CO limit specified. CPS also suggested adding an exemption from the CO analyzer requirement for acid rain peaking units which use meet the requirements of 40 CFR Part 75, Appendix E, since such units are not even required to install a NO_x monitor under Appendix E. CPS commented that Appendix E allows stack testing for NO_x every five years or 3,000 operating hours, in lieu of installing a CEMS, as long as the unit maintains its peaking status.

Because a CO limit was inadvertently omitted from the proposal and can not be added at this time, there is presently no need for the proposed CO monitoring requirement. Since the commission is deleting the proposed CO monitoring requirement of §117.143(b), the suggested exemption for acid rain peaking units which use meet the requirements of 40 CFR Part 75, Appendix E is a moot point but will be considered in the event the commission proposes adding a CO limit and monitoring requirement in the future.

CPS commented on §117.143(c)(2), which provides an option in which one CEMS may be shared among multiple units. CPS stated that the requirement that the exhaust stream of each unit be analyzed separately and the requirement that the CEMS meets the applicable certification requirements for each exhaust stream seemed to contradict each other. CPS stated that §117.143(c)(2)(A) and (B) should either be deleted or clarified to mirror the common stack CEMS requirements in 40 CFR Part 75, §75.16.

There is no contradiction between the requirements. In addition, the option to share CEMS among units is consistent with the corresponding rule in the industrial source division of this chapter. The commission has made no change in response to the comment.

CSW suggested that the proposed §117.145(b) be revised to reflect its request that the basis of the system cap of §117.138 be changed to an annual average.

The commission agrees and has made the suggested revision.

CSW suggested that the proposed §117.149(d)(1)(B) be deleted as part of its request that the basis of the system cap of §117.138 be changed to an annual average.

The commission agrees and has made the suggested revision and has renumbered the proposed §117.149(d)(1)(A) as §117.149(d)(1). In addition, since the system cap has been changed to an annual basis, the commission has changed the proposed semiannual reporting periods of §117.138(g) and §117.149(d) to an annual calendar year basis.

Richards and four individuals suggested that emissions of air toxics from cement kilns in Ellis County can be directly linked with the appearance of rare diseases, including cancer, and urged that these emissions be reduced. Eleven other individuals generally opposed the burning of waste-derived fuel in cement kilns. Another individual recommended that burning of waste-derived fuel be reduced through changes in manufacturing processes which minimize the volume of waste generated.

The purpose of the proposed rulemaking is to address emissions of ozone precursors (specifically, NO_x) in order to help bring ozone nonattainment areas into compliance and to help keep attainment and near-nonattainment areas from going into nonattainment. The proposal does not address emissions of air toxics, which instead are regulated by other commission rules as well as a variety of federal standards. However, the Community Air Toxics Monitoring network currently includes a total of 44 monitors in 18 counties, with two in Ellis County, two in Dallas County, and one in Tarrant County. Should this air toxics monitoring indicate levels of concern, the commission will take appropriate action to ensure that health effects concerns are thoroughly addressed. Because the individual's suggestion is beyond the scope of this rulemaking, the commission has made no change in response to this comment.

Alamo stated that the rule should include a maximum cost (in dollars per ton of NO_x reduced), while Capitol stated that the commission should provide some assurance that the rules will have a reasonable economic impact on the cement industry.

The commission agrees that cost should be taken into account in the development of control strategies and has done so. However, the commission disagrees with the suggested concept of including a maximum cost (in dollars per ton of NO_x reduced) in the proposed rules. Such a concept would not ensure that the necessary emission reductions occur. In addition, the concept raises numerous issues such as the calculation methodology, enforceability, and especially the cutoff level. For example, the commission is aware of one company that spent approximately $31,000 per ton to comply in an ozone nonattainment area while the company was in Chapter 11 bankruptcy. The commission has made no change in response to the comments.

No comments were received on §117.260, concerning Definitions. However, in conjunction with the revisions to §117.265, concerning Emission Specifications, described later in this preamble, the commission has added definitions of "low-NO_x burners" and "mid-kiln firing" to §117.260.

Alamo and Capitol commented on §117.261. Alamo suggested that Ector and Nolan Counties should be included so that the two west Texas cement plants are included in the NO_x reduction requirements. Alamo stated that it was unfair that the cement plants in east and central Texas were subject to the limits while these two west Texas cement plants were not.

The commission cannot revise §117.261 to apply in Ector and Nolan Counties in this rulemaking because the cement plants in those counties would not have had adequate notice and opportunity to comment. Regarding the commenter's assertion that the rules are unfair to cement plants in the eastern half of Texas, the rules are targeting the eastern half of the state because modeling

(described in detail elsewhere in this preamble) has shown that NO_x emissions from sources in that area are contributing to exceedances of the one-hour ozone NAAQS in ozone nonattainment areas as well as contributing to elevated ozone levels in near-nonattainment areas. The commission believes that it is appropriate for those sources which are contributing to the ozone problem to be part of the solution. Consequently, the commission has made no change in response to the comment.

Capitol questioned whether NO_x emissions from its cement plant in San Antonio impact ozone concentrations in DFW and stated that the rules' applicability should be limited to Ellis County until it is demonstrated that emissions from cement plants in other counties are contributing to an exceedance of the ozone standard.

As noted earlier, the proposed controls are based upon a body of circumstantial evidence from aircraft measurements, seasonal modeling, back trajectories, and statistical studies indicating that electric generating facilities and cement kilns in central and eastern Texas contribute to the background levels of NO_x which impact the DFW area. Documents explaining these additional studies are included as appendices to the SIP.

It has come to the commission's attention that Hays County was misspelled in §117.261. The commission has corrected the spelling.

Holnam commented on §117.265 and noted that in the preamble to the proposed rules, the commission solicited comments regarding the technical feasibility and cost-effectiveness of NO_x emission reductions beyond those which would be achieved by the proposed cement kiln rules. Holnam noted that the rule proposal further stated that if the commission determined that NO_x emission reductions beyond those which would be achieved by the proposed rules are technically feasible and cost-effective, then in the adoption of the final rules the commission might incorporate more stringent emission reduction requirements. Holnam stated that adoption of more stringent limits than those proposed would not comply with the notice and opportunity for comment sections of the APA (specifically, Texas Government Code, §2001.023 and §2001.029) and cited a court case *(State Board of Insurance v. Deffebach, 631 S.W.2d 794, 801) (Tex. App.-Austin 1982, writ ref'd n.r.e)* which it claimed made such action illegal.

The commission disagrees with the commenter's interpretation of the caselaw cited. As long as the adopted rules do not regulate new parties or affect new subjects of regulation and the agency does not adopt rules which are completely different rules than those proposed, there is no requirement that an agency repropose the rules prior to adoption. The commission believes that a change in the emission limits would not be enough to require reproposal especially given the fact that the regulated industry was put on notice in the rule proposal preamble that the commission would consider lowering the standards during the comment period.

Holnam further stated that the commission's air permit staff accepted a NO_x emission level of approximately 5.4 pounds per ton (lbs/ton) of clinker produced as best available control technology (BACT) for its new preheater-precalciner kiln in Ellis County.

The commission disagrees with the commenter. The company's recently-amended permit (Permit No. 8996/PSD-TX-454M2) allows up to 770 tons per year (tpy) of NO_x emissions from each of two cement kilns with a maximum allowable production rate of 7,000 tpd of clinker. At maximum production, this represents an average NO_x emission level of 1.4 lbs/ton of clinker produced.

ALAT, Billion, Cleburne, Dallas, Dallas Sierra Club, DAR, GPTC, LWVTC, LWVTX, SCLSC, Turner, TWCA, and 577 individuals commented that the requirements of §117.265 are not stringent enough. Alamo, Capitol, and Cemex commented that the proposed limits are too stringent. Alamo, Capitol, Cemex, and ECCI suggested that the proposed limits be changed to reflect the equipment-based standards (low-NO_x burners, mid-kiln firing, or equivalent) proposed by the EPA in the Ozone Transport Federal Implementation Plan. Tulsa, OPG, and eight individuals supported the proposed requirements. One individual stated that cement kilns in Ellis County should be required to reduce NO_x emissions by 90%; DAR and an individual recommended 80% to 90%; TWCA and six individuals recommended 88%; ALAT, Dallas Sierra Club, SCLSC, and 21 individuals recommended 80%; one individual recommended 70% to 80%; GFWSC and one individual recommended 70%; SCATC/SPAC and an individual recommended 50% to 70%; one individual recommended 60%; Dallas, Goodman, LWVTC, LWVTX, NAACP, and 510 individuals recommended 50%; Cleburne and the Steering Committee recommended up to 50%; and two individuals recommended 40%. DAR and NAACP stated that anything less than a 50% reduction for Ellis County cement plants raises issues of environmental justice for residents of southern Dallas and Tarrant Counties.

The equipment-based standards suggested by Alamo, Capitol, Cemex, and ECCI would not achieve the necessary emission reductions because some cement kilns are already equipped to meet the suggested equipment-based standards and consequently would not have to make further reductions. Rather than setting equipment-based standards, the commission believes that it is more appropriate to establish emission limits because this approach provides more flexibility so that individual kilns can be evaluated to determine the most cost-effective approach to reduce NO_x emissions.

Regarding the specific emission limits for Ellis County cement kilns, review of the company's emissions inventory and associated data subsequent to publication of the proposal indicates that post-1996 process modifications (mid-kiln firing of tires, and addition of steel slag) at the North Texas wet process kilns have reduced NO_x emissions by 30% as of 1998 such that these kilns can meet a NO_x limit of 4.0 lb/ton of clinker. This emission limit would represent a NO_x emission reduction of approximately 30% from the 1996 emissions inventory baseline for the Ellis County wet process cement kilns. However, in order for this emission reduction to be creditable in the SIP, it must be enforceable. Consequently, the commission is revising the emission limit in §117.265 to reflect a NO_x limit of 4.0 lb/ton of clinker for wet process cement kilns in Ellis County. To provide additional flexibility in all affected counties yet still ensure that all reasonable emission reduction measures have been implemented, the commission has added an option which

provides that each kiln equipped with low-NO_x burners and mid-kiln firing is not required to meet the NO_x emission limits. As a practical matter, the commission expects that North Texas and TXI would utilize either this equipment standard option or the source cap option of §117.283 (described later in this preamble) rather than directly complying with the emission limits of §117.265, regardless of whether the limit was set at 4.0 or 6.0 lb/ton of clinker for wet process kilns in Ellis County.

Regarding the commenters' concerns about environmental justice, the commission notes that the adopted emission limits will result in substantial NO_x emission reductions of approximately 30% from the 1996 baseline, despite a 74% increase in clinker production capacity at the Ellis County cement plants since 1996. Additionally, NO_x is not generally associated with environmental justice concerns because it does not have the localized impact of VOCs, especially toxics. Regarding the desire of many commenters that greater emission reductions be required of Ellis County cement kilns, the commission believes that the adopted limits are the most stringent that are reasonably achievable for the wet process kilns in Ellis County. The significant post-1996 combustion modifications at North Texas described earlier reduced NO_x emissions sufficiently in 1998 to achieve approximately a 30% NO_x emission reduction from 1996 levels. TXI will be bringing a new preheater/precalciner kiln on-line by the end of 2000. This new kiln will be equipped with low-NO_x burners and staged combustion, thus minimizing thermal NO_x generated from the heating of raw materials prior to entry to the kiln. TXI's existing No. 2 and No. 3 wet process kilns will not be allowed to operate when the new preheater/precalciner kiln is in operation. However, TXI will continue to operate its No. 1 and No. 4 wet process kilns after the new kiln is

operating. In order to address previous odor complaints related to sulfur compounds, the commission has required TXI's wet process kilns to maintain an average oxygen content, as measure at the kiln exit, of at least 0.75% by volume on a five-minute average. While this successfully resolved the odor situation, excess oxygen has the unfortunate side effect of resulting in the formation of additional NO_x. Even if these kilns were equipped with low-NO_x burners and mid-kiln firing of tires to reduce NO_x, it is unlikely that the company would be able to meet the NO_x limit for wet kilns specified in §117.265. As discussed elsewhere in this preamble, no reasonably effective and practical post-combustion controls are currently available for wet process kilns. Consequently, the commission believes it is appropriate to revise §117.283 to allow the Ellis County cement kilns to participate in the source cap. This will allow TXI to operate its new kiln below the permit limits and apply the difference toward the required emission reductions from its wet process kilns. The necessary NO_x emission reductions will still be achieved with this approach, but TXI and North Texas will have additional flexibility in making the emission reductions. Holnam's two preheater/precalciner kilns (one existing, one recently-permitted) will be equipped with low-NO_x burners and operated at reduced combustion air input (sub-stoichiometric conditions) to reduce NO_x emissions by approximately 27.5% from 1996 levels, despite a doubling of clinker production capacity. The commission expects that Holnam will be able to comply with the NO_x limit of 2.8 lb/ton of clinker for preheater/precalciner kilns, based upon its permit.

DAR stated that low-NO_x burners and mid-kiln firing of tires are viable control technologies for wet process cement kilns and together could reduce NO_x emissions from the North Texas and TXI wet kilns by 50% or more.

The commission agrees that low-NO_x burners and mid-kiln firing of tires are viable control technologies for wet process cement kilns, such as those at North Texas and TXI in Ellis County. Low NO_x burner technology is based on producing an early ignition of the fuel in an oxygen deficient atmosphere in order to reduce the formation of NO_x. Low NO_x burners require an indirect firing system for solid fuels, which allows the primary air to be reduced about 6.0-10%, resulting in less NO_x formation. In Table 2-2 of the EPA's alternative control techniques (ACT) guidance document titled *Alternative Control Techniques Document -- NO_x Emissions from Cement Manufacturing* (EPA-453/R-94-004, March 1994), the EPA estimates that NO_x reductions from conversion to low-NO_x burners range from 20-30% and estimates that NO_x reductions from mid-kiln firing of tires range from 20-40%. On page 7-2 of the ACT, EPA assumes a 25% reduction efficiency for each control measure. However, it should be noted that the percentages are not additive. Thus, while it might be reasonable to expect better than a 25% NO_x reduction from use of both low-NO_x burners and mid-kiln firing of tires at a wet kiln, it is highly unlikely that a 50% reduction would be achieved.

DAR and five individuals suggested that post-combustion controls (SCR and SNCR) are viable options for cement kilns. DAR also stated that SCR has been used successfully on boilers, internal combustion engines, and gas turbines, as well as on coal-fired boilers where exhaust gases contain a significant amount of particulate and sulfur dioxide (SO_2). Regarding a 1976 trial program which evaluated SCR on three cement kilns (each equipped with an electrostatic precipitator (ESP) for particulate control), DAR stated that while the initial NO_x control efficiencies of 98% had dropped to about 75% due to catalyst coating after seven months of operation, the efficiency was still over 50%. DAR also suggested that particulate control technology (ESPs or baghouses) could be used prior to the kiln exhaust stream entering the SCR.

Regarding SNCR, DAR stated that this technology could be applied to dry kilns. DAR acknowledged that there are no installations of SNCR on cement kilns in the United States but stated that in 1995 a cement kiln with built-in SNCR was designed and permitted as BACT in Nevada (albeit never constructed). DAR stated that Iowa's Department of Natural Resources designated SNCR as BACT for a cement plant in that state. DAR also referred to a discussion in the Alternative Control Techniques Document (ACT) which described experimental tests of SNCR on preheater/precalciner kilns. DAR noted that in one test, the ACT stated that in one test the NO_x emissions were reduced by an average of 40% but reached 90% when the ammonia injection rate was 10-20% in excess of stoichiometric, while in a test of a urea-based SNCR the NO_x emission reduction ranged from 27-55%. DAR commented that the ACT stated that in a test on a European preheater-type kiln, an SNCR system with a 1:1 molar ratio of reagent to nitrogen dioxide achieved NO_x emissions of about 70% with ammonia-based reagent and about 35% with urea.

Review of Permit Number 99-A-579P issued by the Iowa Department of Natural Resources (DNR) on November 9, 1999 revealed that SNCR was in fact *not* designated as BACT for this

preheater/precalciner cement kiln. Instead, the company and Iowa DNR negotiated a limit of 4.0 lb NO_x/ton of clinker. The permit requirements for the Nevada cement kiln are irrelevant. Because the plant was never constructed, its SNCR system obviously was never demonstrated in practice.

As noted earlier, a 50% NO_x reduction was the goal, but in some cases technology is not available which would achieve a 50% or higher NO_x reduction. Specifically, for wet process cement kilns, SNCR reportedly has difficulties involved in continuous injection of the reducing agents. The temperature where the reagent (urea or ammonia) is injected is critical because there is no catalyst with SNCR. The necessary temperature is approximately 1,600 to 2,000 degrees Fahrenheit, but on a wet kiln this temperature range occurs roughly halfway down the length of the kiln. While access is possible once per kiln revolution through ports in the kiln (such as those used for mid-kiln firing), the reagent must be added continuously in a specific stoichiometric ratio in order to properly control NO_x emissions and reduce ammonia slip. While SNCR is not applicable to wet process cement kilns, it does appear to be a promising technology for dry process cement kilns. The ACT notes on page 5-17 that "greater NO_x reductions were observed with more than stoichiometric amount of reagent, although there was increasing ammonia 'slip' in the exhaust gases." Regarding the urea-based SNCR test, the ACT notes on page 5-16 that "limited short term data were obtained." Simply put, SNCR has not yet been proven on dry process cement kilns in the United States, although perhaps in the near future additional information will be available which documents that SNCR or some variation of it is a viable NO_x control technique for dry process cement kilns in the United States.

The other post-combustion control available, SCR, has been successfully applied to a variety of combustion sources with a high control efficiency. However, when SCR has been tested on cement kilns, the application of SCR was found to be problematic due to the high concentrations of alkaline particulate matter in the exhaust gas stream. This leads to catalyst fouling, causing high pressure drops and reduced catalyst activity. DAR's own comments confirm that the catalyst was not able to withstand the exhaust gas stream being directed to it. The commission has made no change in response to the comments.

Dallas Sierra Club, DAR, Goodman, and four individuals stated that the reduction percentage should be calculated using 1997 as the base year, while SCLSC and an individual expressed concern that the appropriate base year be used. Dallas Sierra Club and DAR stated that the reduction percentage based on 1997 data is approximately 18% and expressed concern that higher estimated emission reductions had been previously reported. DAR noted that the baseline years for the Ellis County cement plant reductions described in the rule proposal preamble are 1991 for Holnam, 1996 for North Texas, and 1995 for TXI. DAR questioned why the cement plants were given a different baseline than power plants in the same SIP revision and expressed concern that commission representatives met with cement industry representatives in September 1999 and discussed a 30% emission reduction prior to a recommendation in October 1999 by the Steering Committee, which represents the DFW ozone nonattainment area, for a 50% reduction in NO_x emissions from Ellis County cement plants. ED commented that the commission improperly accounts the reductions of Ellis County cement plants.

The table in the rule proposal preamble represented an approximately 40% NO_x reduction from each Midlothian cement company's uncontrolled baseline (i.e., prior to any modifications to reduce NO_x emissions, such as mid-kiln firing of tires, etc.). Since the rule proposal was still being developed at the time, modelers were instructed to boost the emissions reductions to a total of 50%. Hence a factor was applied to the Midlothian area to arrive at an overall 50% reduction. Subsequent modeling will include only the actual emissions reductions achieved.

The DFW Attainment SIP modeling is based upon 1996 episodes, and therefore the EPA has confirmed that 1996 is the appropriate base year. Therefore, the estimated reductions and current modeling are based on 1996 actual emissions as the baseline. In the case of EGFs, a three-year average (1996-1998) was selected as the baseline because fluctuations in ambient temperature patterns often cause significant annual variation in electric demand. An average over three years limits the influence of one particular year on the design value. It should be noted that the Steering Committee recommendation, as adopted on October 29, 1999, was for "up to 50% Ellis County reduction from cement kilns." Therefore, the commission's rule for cement kilns in Ellis County is consistent with this recommendation.

An individual commented on §117.273 and opposed allowing PEMS as an alternative to CEMS for NO_x monitoring. The individual expressed concern that PEMS are not accurate enough and do not reflect actual emissions.

The former TACB authorized PEMS as an alternative to CEMS, because it offered the possibility of equivalent accuracy and lower costs compared to CEMS, and an opportunity to reduce emissions. After more operating experience has been achieved with PEMS, an evaluation of its ability to consistently track NO_x emissions over time will be needed. The commission has made no change in response to the comment.

Holnam commented on §117.273 and requested that the rule be revised so that substantially equivalent requirements in a new source review (NSR) permit could be substituted. Holnam also commented on the notification, recordkeeping, and reporting requirements of §117.279 and likewise requested that the rule be revised so that substantially equivalent requirements in an NSR permit could be substituted.

While the commission appreciates the commenter's desire to eliminate duplication of identical or similar requirements between NSR permit provisions and the rule, the NSR permit requirements are variable from one permit to another and, in some cases, non-existent for the information needed to demonstrate compliance with the requirements of §117.273 and §117.279. Consequently, the commission has made no change in response to the comments.

Cemex and Holnam commented on the proposed §117.283, which provides an alternative to complying with the NO_x emission limits of §117.265 by allowing an owner or operator to choose to reduce total NO_x emissions from all cement kilns at the account to at least 30% less than the total NO_x emissions from all cement kilns in the account's 1997 emissions inventory. Holnam noted that the proposed §117.283 applies to cement plants in Bexar, Comal, Hays, and McLennan Counties. Holnam stated that it does not believe the commission is justified in excluding Ellis County from the source cap and stated that the commission should provide evidence that Ellis County is distinguishable from Bexar, Comal, Hays, and McLennan Counties if Ellis County is excluded.

The commission has revised §117.283 to allow Ellis County cement plants to participate in the source cap because it has determined that this will result in essentially the same emission reduction as if the affected cement kilns met the limits of §117.265 directly. This revision is necessary to allow in-plant trading between the cement kilns at each Ellis County cement plant, thus providing more flexibility so that the owners or operators can evaluate individual units to determine the most cost-effective approach to reduce NO_x emissions. As discussed earlier, the commission has revised the base year to 1996. In addition, the commission has revised §117.283 to specify that the source cap is on a 30-day rolling average basis for consistency with the emission specifications of §117.265. Finally, the commission changed the units of the source cap from tpd to ppd for consistency with the emissions inventory reporting requirements.

Cemex advised that review of data from a recently-installed CEMS revealed that the 1993 stack test data which was used to report NO_x emissions in emissions inventories through 1998 was underestimating the actual NO_x emissions. Specifically, Cemex indicated that the reported 1997 NO_x emissions of 1,557 tpy should have been 2,286 tpy. Cemex estimated the 1999 NOx emissions using the new CEMS to be 2,276 tpy. Consequently, Cemex expressed a preference for basing the source cap on the 1999 emissions inventory rather than the 1997 emissions inventory.

As noted earlier in this preamble, the EPA has confirmed that 1996 is the appropriate base year because the modeling is based upon 1996 episodes. While it is unfortunate that the 1993 stack sampling data underreported the actual emissions, and consequently resulted in underreporting of emissions in the emissions inventories through 1998, this rulemaking is not the appropriate mechanism for adjusting a previous emissions inventory. The commission has made no change in response to the comment.

Cemex stated that they would be unable to achieve a 30% reduction of NO_x emissions without major modifications to the preheating tower and precalcining system. Cemex stated that its kiln system is uniquely different than other preheater-precalciner kiln systems in Texas in that combustion air for the precalciner is drawn through the rotary kiln and not through the tertiary ducting as is the normal case (air-through as opposed to air-separate design), and that this design inherently generates higher levels of NO_x due to excess oxygen in the kiln and precalciner. Cemex stated that vendor quotes for the necessary modifications to its preheating tower and precalcining system exceed $10 million, or at least $14,000 per ton of NO_x reduced.

The commenter did not provide data supporting its reported vendor quotes for its cement kiln, nor is there any indication that the company explored all possible options to reduce NO_x emissions. Even if the company's estimates are accurate and represent the least expensive control option, the commission expects that the forthcoming banking and trading program would lower the cost of compliance.

Holnam suggested the addition of a site cap which would allow an owner or operator to choose to reduce total NO_x emissions from all NO_x emission sources at the account to meet the desired emission reductions. Holnam also stated that any requirement for low-emitting trucks is solely within the EPA's jurisdiction under the FCAA, Title II.

In conjunction with §101.29 of this title (Emission Credit Banking and Trading), §117.570 (Trading) allows an owner or operator to apply an emission reduction credit (ERC), mobile emission reduction credit (MERC), discrete emission reduction credit (DERC), or mobile discrete emission reduction credit (MDERC) toward meeting specifically-listed emission limits. The commission believes that §117.570 is clearly the appropriate section for addressing the use of ERCs, MERCs, DERCs, or MDERCs. However, the changes to §117.570 which would be necessary to make this section available to cement kilns are substantial enough that these changes can not be made at this time. The commenter's suggestion will also be addressed during the development of the forthcoming rules for an emissions banking and trading program.

It has come to the commission's attention that Hays County was misspelled in §117.283(a). The commission has corrected the spelling.

Austin, Brazos, CEED, CPS, CSW, LCRA, NACC, San Miguel, TMPA, and TXU commented on the May 1, 2003 compliance date in §117.512 for utility electric power boilers and stationary gas turbines in the 31 attainment counties in east and central Texas. Austin, Brazos, CEED, CPS, CSW, LCRA, TMPA, and TXU stated that a longer compliance schedule was necessary, especially due to limited availability of engineering, fabrication, and installation contractors for controls. Austin expressed concern that electric reliability across Texas since retrofitting of each generating unit will require that the unit be out of service for several weeks or months, which potentially could result in shortfalls in generating capacity. NACC also expressed concern about the potential for brownouts and blackouts. Brazos, CEED, CSW, LCRA, NACC, San Miguel, and TMPA suggested a May 1, 2005 compliance date, with TMPA suggesting the inclusion of mandatory compliance milestones based on a commission-approved, facility-specific schedule. Austin and CPS suggested a May 1, 2005 compliance date for units that are not subject to the May 1, 2003 cost-recovery deadline in SB 7 (TUC, §39.263).

Much of the construction work associated with installing post-combustion controls can be accomplished while the unit is in operation, and the remaining work can be done during a regularly scheduled maintenance shutdown, thus minimizing the impact on generating capacity. As noted earlier in this preamble, the commission considers the January 1999 joint PUCT/TNRCC report, "Electric Restructuring and Air Quality: A Preliminary Analysis of Reductions and Costs of NO_x Controls from Electric Utility Boilers in Texas," to be an indicator that the economic impacts of the proposed emission limits will not result in widespread shutdowns. Therefore, the commission believes that the commenters' concerns about the potential for brownouts and blackouts are overstated. Nevertheless, in order to address the commenters' concerns about the availability of engineering, fabrication, and installation contractors, the commission has revised §117.512 to specify a May 1, 2005 compliance date for units owned by utilities which are not subject to the May 1, 2003 cost-recovery deadline in SB 7 (TUC, §39.263(b)). The commission has retained a May 1, 2003 compliance date for units owned by

utilities which are subject to the May 1, 2003 cost-recovery deadline in SB 7 (TUC, §39.263(b)) to ensure consistency with SB 7.

Cemex commented on the May 1, 2003 compliance date in §117.524 for cement kilns in Bexar, Comal, Ellis, Hays, and McLennan Counties. Cemex suggested that the compliance date be set at 36 months after the effective date of the new rules.

For adoption by the commission on April 19, 2000, the effective date is estimated to be May 14, 2000. Since 36 months from this date is only two weeks later than the proposed May 1, 2003 compliance date, the commission is retaining the May 1, 2003 compliance date for cement kilns in Ellis County to ensure that the necessary emission reductions which have the most impact on DFW are achieved as soon as practicable. The commission is revising the compliance date for cement kilns in Bexar, Comal, Hays, and McLennan Counties to May 1, 2005 to provide additional time for compliance. As part of the Attainment SIP mid-course review (anticipated to be completed by December 2003) there will be an opportunity for the commission to evaluate the implementation status of the rule at that time.

It has come to the commission's attention that Hays County was misspelled in §117.524. The commission has corrected the spelling.

STATUTORY AUTHORITY

The amendments and new sections are adopted under the Texas Health and Safety Code, TCAA, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; and §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state’s air, such as the SIP.

SUBCHAPTER A : DEFINITIONS

§117.10

§117.10. Definitions.

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

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

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

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

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

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

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

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

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

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

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

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

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

(A) All boilers, steam generators, auxiliary steam boilers, and stationary gas turbines that generate electric energy for compensation; are owned or operated by a municipality or a Public Utility Commission of Texas regulated utility, or any of its successors; and are entirely located in one of the following ozone nonattainment areas:

(i) Beaumont/Port Arthur;

(ii) Dallas/Fort Worth;

(iii) Houston/Galveston; or

(B) All boilers, steam generators, auxiliary steam boilers, and stationary gas turbines 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.

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

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

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

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

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

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

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

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

(19) **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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(28) **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.

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

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

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

(32) **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.

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

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

(35) **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.

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

(37) **Stationary gas turbine** - Any gas turbine system that is gas and/or liquid fuel fired with or without power augmentation. This unit is either attached to a foundation at a major source

or is portable equipment operated at a specific major source for more than 90 days in any 12-month period. Two or more gas turbines powering one shaft shall be treated as one unit.

(38) **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.

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

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

(41) **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.

(42) **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.

(43) **Unit** - Any boiler, steam generator, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section.

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

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

SUBCHAPTER B: COMBUSTION AT EXISTING MAJOR SOURCES

DIVISION 2: UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS

§§117.131, 117.133 - 117.135, 117.138, 117.141, 117.143, 117.145, 117.147, 117.149

STATUTORY AUTHORITY

The new sections are adopted under the Texas Health and Safety Code, TCAA, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; and §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air, such as the SIP.

§117.131. Applicability.

The provisions of this division shall apply to each utility electric power boiler and stationary gas turbine 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.

§117.133. Exemptions.

The provisions of this division, except as may be specified in §117.143 and §117.149 of this title (relating to Continuous Demonstration of Compliance; and Notification, Recordkeeping, and Reporting Requirements), do not apply to:

(1) utility electric power boilers or stationary gas turbines if the annual heat input does not exceed 2.2 (10^{11}) British thermal units per year, averaged over the three most recent calendar years;

(2) stationary gas turbines and auxiliary boilers which are:

(A) used solely to power other units during start-ups; or

(B) demonstrated to operate no more than an average of 10% of the hours of the year, averaged over the three most recent calendar years, and no more than 20% of the hours in a single calendar year; and

(3) each unit that generates electric energy primarily for internal use but that, averaged over the three most recent calendar years, sold less than one-third of its potential electrical output capacity to a utility power distribution system.

§117.134. Gas-Fired Steam Generation.

(a) Subsections (b), (c), and (d) of this section (emission specifications adopted by the Texas Air Control Board in 1972) apply in Fannin, Hood, and Palo Pinto Counties. This section shall no longer apply in Fannin and Hood Counties after the applicable final compliance date specified in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(b) No person shall allow emissions of nitrogen oxides (NO_x), calculated as nitrogen dioxide (NO_2), from any "opposed-fired" steam generating unit of more than 600,000 pounds per hour (lbs/hr) maximum continuous steam capacity to exceed 0.7 pound per million British thermal units (lb/MMBtu) heat input, maximum two-hour average, at maximum steam capacity. An "opposed-fired" steam generating unit is defined as a unit having burners installed on two opposite vertical firebox surfaces.

(c) No person shall allow emissions of NO_x, calculated as NO_2, from any "front-fired" steam generating unit of more than 600,000 lbs/hr maximum continuous steam capacity to exceed 0.5 lb/MMBtu heat input, maximum two-hour average, at maximum steam capacity. A "front-fired" steam generating unit is defined as a unit having all burners installed in a geometric array on one vertical firebox surface.

(d) No person shall allow emissions of NO_x, calculated as NO_2, from any "tangential-fired" steam generating unit of more than 600,000 lbs/hr maximum continuous steam capacity to exceed 0.25 lb/MMBtu heat input, maximum two-hour average, at maximum steam capacity. A "tangential-fired" steam generating unit is defined as a unit having burners installed on all corners of the unit at various elevations.

(e) Existing gas-fired steam generating units of more than 600,000 lbs/hour, but less than 1,100,000 lbs/hr, maximum continuous steam capacity are exempt from the provisions of this section, provided the total steam generated from the unit during any one calendar year does not exceed 30% of the product of the maximum continuous steam capacity of the unit times the number of hours in a year. Written records of the amount of steam generated for each day's operation shall be made on a daily basis and maintained for at least three years from the date of each entry. Such records shall be made available upon request to representatives of the executive director, EPA, or any local air pollution control agency having jurisdiction.

§117.135. Emission Specifications.

In accordance with the compliance schedule in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas), the owner or operator of each utility electric power boiler or stationary gas turbine shall ensure that emissions of nitrogen oxide (NO_x) do not exceed the following rates, in pound per million British thermal unit (lb/MMBtu) heat input on an annual (calendar year) average:

(1) electric power boilers:

(A) gas-fired, 0.14;

(B) coal-fired, 0.165;

(2) stationary gas turbines:

(A) subject to TUC, §39.264 (except units designated in accordance with TUC, §39.264(i)), 0.14;

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

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

§117.138. System Cap.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.135 of this title (relating to Emission Specifications) 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 unit within an electric power generating system, as defined in §117.10(11)(B) of this title (relating to Definitions), that would otherwise be subject to the NO_x emission limits of §117.135 of this title must be included in the system cap.

(c) The annual average emission cap shall be calculated using the following equation.

Figure: 30 TAC §117.138(c)

$$\begin{array}{c}NO_x \text{ annual} \\ \text{average emission cap} \\ \text{(tons/year)}\end{array} = \sum_{i=1}^{N} (H_i \times R_i)/2000$$

Where:

i = Each unit in the electric power generating system
N = The total number of units in the emission cap

H_i = The average of the annual heat input for each unit in the emission cap, in million British thermal units (Btu) per year, as certified to the executive director, for 1996, 1997, and 1998
R_i = The emission limit of §117.135 of this title

(d) The NO_x emissions monitoring required by §117.143 of this title (relating to Continuous Demonstration of Compliance) for each unit in the system cap shall be used to demonstrate continuous compliance with the system cap.

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

(1) if the NO_x monitor is a continuous emissions monitoring system (CEMS):

(A) subject to 40 Code of Federal Regulations (CFR) 75, use the missing data procedures specified in 40 CFR 75, Subpart D (Missing Data Substitution Procedures);

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

(2) use Appendix E monitoring in accordance with §117.143(d) of this title;

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

(A) use the methods specified in 40 CFR 75, Subpart D;

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

(4) if the methods specified in paragraphs (1) - (3) of this subsection are not used, the owner or operator must use the maximum emission rate as measured by the testing conducted in accordance with §117.141(d) of this title (relating to Initial Demonstration of Compliance).

(f) The owner or operator of any unit subject to a system cap shall maintain daily records indicating the NO_x emissions and fuel usage from each unit and summations of total NO_x emissions and fuel usage for all units under the system cap on a daily basis. Records shall also be retained in accordance with §117.149 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(g) The owner or operator of any unit subject to a system cap shall submit annual reports for the monitoring systems in accordance with §117.149 of this title. The owner or operator shall also report any exceedance of the system cap emission limit in the annual report and shall include an analysis of the cause for the exceedance with appropriate data to demonstrate the amount of emissions in excess of the applicable limit and the necessary corrective actions taken by the company to assure future compliance.

(h) The owner or operator of any unit subject to a system cap shall demonstrate initial compliance with the system cap in accordance with the schedule specified in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(i) A unit which is permanently retired or decommissioned and rendered inoperable may be included in the source cap emission limit, provided that the permanent shutdown occurred on or after January 1, 1999. The source cap emission limit is calculated in accordance with subsection (b) of this section.

(j) Emission reductions from shutdowns or curtailments which have been used for netting or offset purposes under the requirements of Chapter 116 of this title may not be included in the baseline for establishing the cap.

(k) For the purposes of determining compliance with the source cap emission limit, the contribution of each affected unit that is operating during a startup, shutdown, or upset period shall be calculated from the NO_x emission rate measured by the NO_x monitor, if operating properly. If the NO_x monitor is not operating properly, the substitute data procedures identified in subsection (e) of this section must be used. If neither the NO_x monitor nor the substitute data procedure are operating properly, the owner or operator must use the maximum daily rate measured during the initial demonstration of compliance, unless the owner or operator provides data demonstrating to the satisfaction of the executive director and EPA that actual emissions were less than maximum emissions during such periods.

§117.141. Initial Demonstration of Compliance.

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

(1) Test for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen (O_2) emissions.

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

(3) Testing shall be performed in accordance with the schedule specified in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(b) The tests required by subsection (a) of this section shall be used for determination of initial compliance with the emission limits of this division. Test results shall be reported in the units of the applicable emission limits and averaging periods. 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 §117.211(g) of this title (relating to Initial Demonstration of Compliance).

(c) Continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) required by §117.143 of this title (relating to Continuous Demonstration of Compliance) shall be installed and operational before testing under subsection (a) of this section.

Verification of operational status shall, 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.

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

§117.143. Continuous Demonstration of Compliance.

(a) Nitrogen oxides (NO_x) monitoring. The owner or operator of each unit subject to the emission specifications of this division (relating to Utility Electric Generation in East and Central Texas) shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS), predictive emissions monitoring system (PEMS), or other system specified in this section to measure NO_x on an individual basis.

(b) Carbon monoxide (CO) monitoring. The owner or operator is not required to monitor CO exhaust emissions from each unit subject to the emission specifications of this division.

(c) CEMS requirements.

(1) Any CEMS required by this section shall be installed, calibrated, maintained, and operated in accordance with 40 Code of Federal Regulations (CFR), Part 75 or 40 CFR, Part 60, as applicable.

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

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

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

(d) Acid rain peaking units. The owner or operator of each peaking unit as defined in 40 CFR Part 72.2, may:

(1) 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

(2) use CEMS or PEMS in accordance with this section to monitor NO_x emission rates.

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

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

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

(f) PEMS requirements. The owner or operator of any PEMS used to meet a pollutant monitoring requirement of this section must comply with the following. The required PEMS and fuel flow meters shall be used to demonstrate continuous compliance with the emission limitations of §117.135 of this title (relating to Emission Specifications).

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

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

(A) using a CEMS:

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

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

(B) using a PEMS.

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

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

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

(B) §117.213(f) of this title.

(g) Gas turbine monitoring. The owner or operator of each stationary gas turbine subject to the emission specifications of §117.135 of this title, instead of monitoring emissions in accordance with the monitoring requirements of 40 CFR 75, may comply with the following monitoring requirements:

(1) for stationary gas turbines rated less than 30 megawatt (MW) or peaking gas turbines (as defined in §117.10 of this title) which use steam or water injection to comply with the emission specification of §117.135(2) of this title:

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

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

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

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

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

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

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

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

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

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

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

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

(k) Data used for compliance. After the initial demonstration of compliance required by §117.141 of this title (relating to Initial Demonstration of Compliance) the methods required in this section shall be used to determine compliance with the emission specifications of this division. Compliance with the emission limitations may also be determined at the discretion of the executive director using any commission compliance method.

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

§117.145. Final Control Plan Procedures.

(a) The owner or operator of units listed in §117.131 of this title (relating to Applicability) shall submit a final control report to show compliance with the requirements of §117.135 of this title (relating to Emission Specifications). The report must include:

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

(A) §117.135 of this title; or

(B) §117.138 of this title (relating to System Cap);

(2) the methods of control of NO_x emissions for each unit;

(3) the emissions measured by testing required in §117.141 of this title (relating to Initial Demonstration of Compliance);

(4) the submittal date, and whether sent to the Austin or the regional office (or both), of any compliance stack test report or relative accuracy test audit report required by §117.141 of this title which is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any unit with a claimed exemption from the emission specification of §117.135 of this title.

(b) In addition to the requirements of subsection (a) of this section, the owner or operator of each source complying with §117.138 of this title shall submit:

(1) the calculations used to calculate the annual average system cap allowable emission rate;

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

(A) the average annual heat input H_i specified in §117.138(c) of this title;

(B) the method of monitoring emissions; and

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

(3) an explanation of the basis of the value of H_i.

(c) The report must be submitted by the applicable date specified for final control plans in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas). The plan must be updated with any emission compliance measurements submitted for units using a continuous emissions monitoring system or predictive emissions monitoring system and complying with the system cap annual average emission limit, according to the applicable schedule given in §117.512 of this title.

§117.147. Revision of Final Control Plan.

A revised final control plan may be submitted by the owner or operator, along with any required permit applications. Such a plan shall adhere to the emission limits and the final compliance dates of this division (relating to Utility Electric Generation in East and Central Texas). The revision of the final control plan shall be subject to the review and approval of the executive director.

§117.149. Notification, Recordkeeping, and Reporting Requirements.

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

(b) Notification. The owner or operator of a unit subject to the emission specifications of this division (relating to Utility Electric Generation in East and Central Texas) shall submit notification to the executive director as follows:

(1) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.141 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any continuous emissions monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS) performance evaluation conducted under §117.143 of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(c) Reporting of test results. The owner or operator of an affected unit shall furnish the executive director and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.141 of this title or any CEMS or PEMS performance evaluation conducted under §117.143 of this title:

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

(2) not later than the appropriate compliance schedule specified in §117.512 of this title (relating to Compliance Schedule for Utility Electric Generation in East and Central Texas).

(d) Annual reports. The owner or operator of a unit required to install a CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system under §117.143 of this title shall report in writing to the executive director on an annual basis any exceedance of the applicable emission limitations in this division and the monitoring system performance. All reports shall be postmarked or received by January 31 following the end of each calendar year. Written reports shall include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations (CFR), Part 60, §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the unit operating time during the reporting period. For stationary gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.143 of this title, excess emissions are

computed as each one-hour period during which the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial demonstration of compliance test required by §117.141 of this title;

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

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

(4) when no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report; 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, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system downtime for the reporting period is less than 5.0% of the total unit operating time for the reporting period, only a summary report form (as outlined in the latest edition of the commission's "Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports") shall be submitted, unless otherwise requested by the executive director. If the total duration of excess emissions for the reporting period is greater than or equal to 1.0% of the

total operating time for the reporting period or the CEMS or steam-to-fuel or water-to-fuel ratio monitoring system downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

(e) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain records of the data specified in this subsection. Records shall be kept for a period of at least five years and made available for inspection by the executive director, EPA, or local air pollution control agencies having jurisdiction upon request. Operating records for each unit shall be recorded and maintained at a frequency equal to the applicable emission specification averaging period, or for units claimed exempt from the emission specifications based on low annual capacity factor, monthly. Records shall include:

(1) emission rates in units of the applicable standards;

(2) gross energy production in MW-hr (not applicable to auxiliary boilers);

(3) quantity and type of fuel burned;

(4) the injection rate of reactant chemicals (if applicable); and

(5) emission monitoring data, pursuant to §117.143 of this title, including:

(A) the date, time, and duration of any malfunction in the operation of the monitoring system, except for zero and span checks, if applicable, and a description of system repairs and adjustments undertaken during each period;

(B) the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, PEMS, or operating parameter monitoring systems; and

(C) actual emissions or operating parameter measurements, as applicable;

(6) the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.141 of this title; and

(7) records of hours of operation.

SUBCHAPTER B: COMBUSTION AT EXISTING MAJOR SOURCES

DIVISION 4: CEMENT KILNS

§§117.260, 117.261, 117.265, 117.273, 117.279, 117.283

STATUTORY AUTHORITY

The new sections are adopted under the Texas Health and Safety Code, TCAA, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; and §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state’s air, such as the SIP.

§117.260. Cement Kiln Definitions.

Unless specifically defined in the Texas Clean Air Act (TCAA) or in the rules of the Texas Natural Resource Conservation Commission (commission), the terms used by the commission have the meanings commonly used in the field of air pollution control. In addition to the terms which are defined by the TCAA, the following terms, when used in this division, shall have the following meanings, unless the context clearly indicates otherwise. Additional definitions for terms used in this division are found in §101.1 of this title (relating to Definitions), §3.2 of this title (relating to Definitions), and §117.10 of this title (relating to Definitions).

(1) **Clinker** - The product of a portland cement kiln from which finished cement is manufactured by milling and grinding.

(2) **Long dry kiln** - A kiln 400 feet or greater in length which employs no preheating of the dry feed. The inlet feed to the kiln is dry.

(3) **Long wet kiln** - A kiln 400 feet or greater in length which employs no preheating of the dry feed. The inlet feed to the kiln is a slurry.

(4) **Low-NO_x burners** - Combustion equipment designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion.

(5) **Mid-kiln firing** - Secondary combustion in kilns by injecting solid fuel at an intermediate point in the kiln using a specially-designed feed injection mechanism for the purpose of decreasing nitrogen oxides (NO_x) emissions through:

(A) burning part of the fuel at a lower temperature; and

(B) reducing conditions at the solid fuel injection point that may destroy some of the NO_x formed upstream in the kiln burning zone.

(6) **Portland cement** - A hydraulic cement produced by pulverizing clinker consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an interground addition.

(7) **Portland cement kiln** - A system, including any solid, gaseous, or liquid fuel combustion equipment, used to calcine and fuse raw materials, including limestone and clay, to produce portland cement clinker.

(8) **Precalciner kiln** - A kiln where the feed to the kiln system is preheated in cyclone chambers and utilizes a second burner to calcine material in a separate vessel attached to the preheater before the final fusion in a kiln which forms clinker.

(9) **Preheater kiln** - A kiln where the feed to the kiln system is preheated in cyclone chambers before the final fusion in a kiln which forms clinker.

§117.261. Applicability.

This division (relating to Cement Kilns) applies to each portland cement kiln in Bexar, Comal, Ellis, Hays, and McLennan Counties that was placed into service before December 31, 1999, except as specified in §117.265 and §117.283 of this title (relating to Emission Specifications; and Source Cap).

§117.265. Emission Specifications.

(a) In accordance with the compliance schedule in §117.524 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, a 30-day rolling average is an average, calculated for each day that fuel is combusted in a cement kiln, of all the hourly emissions data for the preceding 30 days that fuel was combusted in the kiln:

(1) for each long wet kiln:

(A) in Bexar, Comal, Hays, and McLennan Counties, 6.0 pounds per ton (lbs/ton) of clinker produced; and

(B) in Ellis County, 4.0 lbs/ton of clinker produced;

(2) for each long dry kiln, 5.1 lbs/ton of clinker produced;

(3) for each preheater kiln, 3.8 lbs/ton of clinker produced; and

(4) for each preheater-precalciner or precalciner kiln, 2.8 lbs/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 limits 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 limit. 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 §117.524 of this title (relating to Compliance Schedule for Cement Kilns).

(c) Each kiln for which low-NO_x burners and mid-kiln firing are installed and operated during kiln operation is not required to meet the NO_x emission limits 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 §117.524 of this title.

§117.273. Continuous Demonstration of Compliance.

(a) Nitrogen oxides (NO_x) monitors. In accordance with the compliance schedule in §117.524 of this title (relating to Compliance Schedule for Cement Kilns), the owner or operator shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) to monitor kiln exhaust NO_x.

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

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

(A) Section 60.13;

(B) Appendix B, Performance Specification 2, for NO_x; and

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

(2) One CEMS may be shared among kilns, provided:

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

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

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

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

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

(2) The PEMS shall meet the requirements of §117.213(f)(2) - (7) of this title (relating to Continuous Demonstration of Compliance).

§117.279. 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 §117.273 of this title (relating to Continuous Demonstration of Compliance) 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 (RATA) conducted under §117.273 of this title:

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

(2) not later than the appropriate compliance date in §117.524 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 shall maintain written or electronic records of the data specified in this subsection. Such records shall be kept for a period of at least five years and shall be made available upon request by authorized representatives of the executive director, EPA, or local air pollution control agencies having jurisdiction. The records shall include:

(1) for each kiln, monitoring records of:

(A) daily nitrogen oxides (NO_x) emissions (in pounds (lbs));

(B) daily production of clinker (in tons); and

(C) average NO_x emission rate (in lbs/ton of clinker produced) on the basis of a 30-day rolling average;

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

(3) records of the results of any stack testing conducted.

§117.283. Source Cap.

(a) As an alternative to complying with the requirements of §117.265 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 30-day rolling average basis. For the purposes of this section, a 30-day rolling average is an average, calculated for each day that fuel is combusted in a cement kiln, of all the hourly emissions data for the preceding 30 days that fuel was combusted in the kiln. A 30-day rolling average emission cap shall be calculated using the following equation.

Figure: 30 TAC §117.283(a)

$$\begin{array}{c} NO_x \text{ 30-day rolling} \\ \text{average emission cap} \\ \text{(pounds/day)} \end{array} = 0.7\sum_{i=1}^{N} R_i$$

Where:

i = Each cement kiln at a single account
N = The total number of cement kilns at the account
R_i = The ozone season daily NO_x emission rate (in ppd) reported in the account's 1996 EI

(b) To qualify for the source cap option available under this section, the owner or operator must submit an initial control plan to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction which 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. 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 shall 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 which have been or will be implemented at each cement kiln; and an explanation of the recordkeeping procedure and calculations which will be used to demonstrate compliance.

(c) Beginning on March 31 of the year following the appropriate compliance date in §117.524 of this title (relating to Compliance Schedule for Cement Kilns), 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 which 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. At a minimum, the report shall include the EPN, FIN, and the highest 30-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 shall 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.

(e) The NO_x emissions monitoring required by §117.273 of this title (relating to Continuous Demonstration of Compliance) for each cement kiln in the source cap shall be used to demonstrate continuous compliance with the source cap.

SUBCHAPTER E: ADMINISTRATIVE PROVISIONS

§117.512, §117.524

STATUTORY AUTHORITY

The new sections are adopted under the Texas Health and Safety Code, TCAA, §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; and §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state’s air, such as the SIP.

§117.512. Compliance Schedule for Utility Electric Generation in East and Central Texas.

The owner or operator of each utility electric power boiler or stationary gas turbine located in Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, and Wharton Counties shall comply with the requirements of Subchapter B, Division 2 of this chapter (relating to Utility Electric Generation in East and Central Texas) as soon as practicable, but no later than the following dates:

(1) May 1, 2003 for units owned by utilities which are subject to the cost-recovery provisions of Texas Utilities Code, §39.263(b); and

(2) May 1, 2005 for all other units.

§117.524. Compliance Schedule for Cement Kilns.

The owner or operator of each portland cement kiln which was placed into service before December 31, 1999 in Bexar, Comal, Ellis, Hays, and McLennan Counties shall be in compliance with the requirements of Subchapter B, Division 4 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.