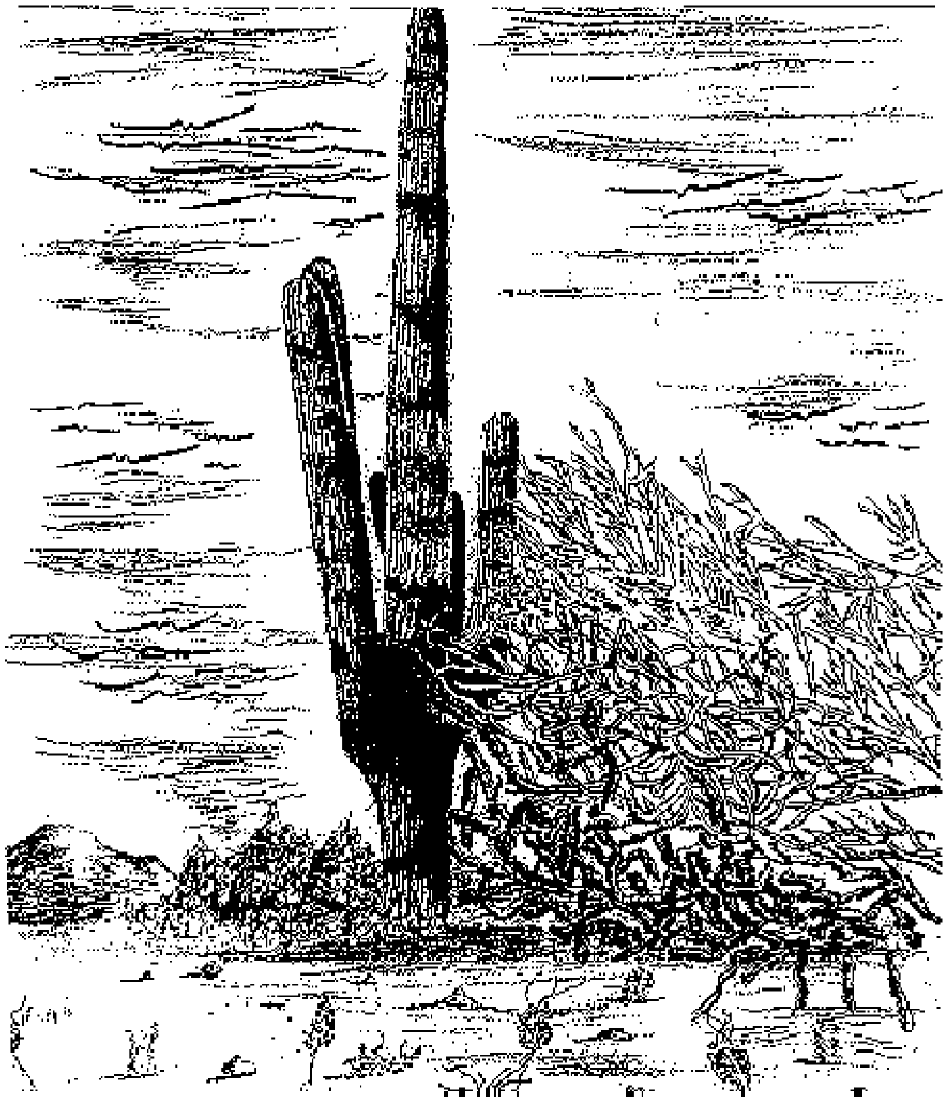
Texas Register

Volume 26 Number 2 January 12, 2001 Pages 267-726



This month's front cover artwork:

Artist: *Tiffany Dallas*

11th grade

Forest Brook High School

School children's artwork has decorated the blank filler pages of the *Texas Register* since 1987. Teachers throughout the state submit the drawings for students in grades K-12. The drawings dress up the otherwise gray pages of the *Texas Register* and introduce students to this obscure but important facet of state government.

We will display artwork on the cover of each *Texas Register*. The artwork featured on the front cover is chosen at random.

The artwork is published on what would otherwise be blank pages in the *Texas Register*. These blank pages are caused by the production process used to print the *Texas Register*. The artwork does not add additional pages to each issue and does not increase the cost of the *Texas Register*.

Texas Register, (ISSN 0362-4781), is published weekly, 52 times a year. Issues will be published by the Office of the Secretary of State, 1019 Brazos, Austin, Texas 78701. Subscription costs: printed, one year $150, six months $100. First Class mail subscriptions are available at a cost of $250 per year. Single copies of most issues for the current year are available at $10 per copy in printed format.

The **Texas Register** is published under the Government Code, Title 10, Chapter 2002. Periodicals Postage Paid at Austin, Texas.

POSTMASTER: Send address changes to the **Texas Register,** P.O. Box 13824, Austin, TX 78711-3824.

a section of the
Office of the Secretary of State
P.O. Box 13824
Austin, TX 78711-3824
(800) 22607199
(512) 463-5561
FAX (512) 463-5569
http://www.sos.state.tx.us
Secretary of State - Henry Cuellar
Director - Dan Procter

Customer Relations
Leti Benavides
LaKiza Fowler-Sibley

Texas Administrative Code
Dana Blanton
Roberta Knight

Texas Register
Leah Billingsley
Carla Carter
Melissa Dix
Ann Franklin
Kris Hogan
Diana Muniz-Franklin
Crystal Ritchey

Circulation/Marketing
Jill S. Ledbetter

ATTORNEY GENERAL

PROPOSED RULES

TEXAS FUNERAL SERVICE COMMISSION

LICENSING AND ENFORCEMENT--PRACTICE AND PROCEDURE

TEXAS DEPARTMENT OF MENTAL HEALTH AND MENTAL RETARDATION

AGENCY AND FACILITY RESPONSIBILITIES

WITHDRAWN RULES

EDWARDS AQUIFER AUTHORITY

GROUNDWATER WITHDRAWAL PERMITS

ADOPTED RULES

BOARD OF VOCATIONAL NURSE EXAMINERS

ADMINISTRATION

EDUCATION

LICENSING

CONTINUING EDUCATION

CONTESTED CASE PROCEDURE

PEER REVIEW AND REPORTING

TEXAS NATURAL RESOURCE CONSERVATION COMMISSION

GENERAL AIR QUALITY RULES

CONTROL OF AIR POLLUTION FROM MOTOR VEHICLES

CONTROL OF AIR POLLUTION FROM MOTOR VEHICLES

CONTROL OF AIR POLLUTION FROM VOLATILE ORGANIC COMPOUNDS

CONTROL OF AIR POLLUTION FROM NITROGEN COMPOUNDS

EDWARDS AQUIFER AUTHORITY

OFFICE OF THE ATTORNEY GENERAL

Under provisions set out in the Texas Constitution, the Texas Government Code. Title 4, §402.042, and numerous statutes, the attorney general is authorized to write advisory opinions for state and local officials. These advisory opinions are requested by agencies or officials when they are confronted with unique or unusually difficult legal questions. The attorney general also determines, under authority of the Texas Open Records Act, whether information requested for release from governmental agencies may be held from public disclosure. Requests for opinions, opinions, and open records decisions are summarized for publication in the ***Texas Register***. The attorney general responds to many requests for opinions and open records decisions with letter opinions. A letter opinion has the same force and effect as a formal Attorney General Opinion, and represents the opinion of the attorney general unless and until it is modified or overruled by a subsequent letter opinion, a formal Attorney General Opinion, or a decision of a court of record. You may view copies of opinions at http://www.oag.state.tx.us. To request copies of opinions, please fax your request to (512) 462-0548 or call (512) 936-1730. To inquire about pending requests for opinions, phone (512) 463-2110.

Opinions

Opinion No. JC-0318

The Honorable Eugene D. Taylor, Williamson County Attorney, County Courthouse Annex, Second Floor, 405 Martin Luther King, Box 3, Georgetown, Texas 78626

Re: Whether article XI, section 11 of the Texas Constitution requires a municipality to fill by special election a vacancy in its governing body arising from an automatic resignation (RQ-0286-JC)

S U M M A R Y

Article XI, section 11 of the Texas Constitution requires a city that has extended the terms of its city council members from two to three years to fill a vacancy resulting from a council member's automatic resignation by holding a special election within 120 days. Such a vacancy may not be filled by appointment. A city council member who automatically resigns holds over in office. A city that fails to hold a special election within 120 days after the date of the automatic resignation as required by article XI, section 11 may not avoid holding a special election until the holdover's term expires.

Opinion No. JC-0319

The Honorable Michael P. Fleming, Harris County Attorney, 1019 Congress, 15th Floor, Houston, Texas 77002-1700

Re: Whether a county commissioners court may condition acceptance of bids for county public works project on attendance at a mandatory prebid conference (RQ-266)

S U M M A R Y

A county commissioners court may not condition acceptance of bids for a county public works project solicited pursuant to the County Purchasing Act, Tex. Loc. Gov't Code Ann. ch. 262, subch. C (Vernon 1999 & Supp. 2000), on attendance at a mandatory prebid conference.

Opinion No. JC-0320

The Honorable Tim Curry, Tarrant County Criminal District Attorney, Tarrant County Justice Center, 401 West Belknap, Fort Worth, Texas 76196-0201

Re: Whether a person who is sentenced to pay a fine and to deferred adjudication probation after pleading guilty to a class C misdemeanor in county court is entitled to an expunction of his arrest record (RQ-0258-JC)

S U M M A R Y

A person who is sentenced to pay a fine and to deferred adjudication probation in a county criminal court is not entitled to an expunction of his arrest record under article 55.01 of the Code of Criminal Procedure.

For further information, please call (512) 463-2110

TRD-200009043
Susan D. Gusky
Assistant Attorney General
Office of the Attorney General
Filed: December 27, 2000

♦ ♦ ♦

Request for Opinion

RQ-0323-JC

Mr. Jim Nelson, Commissioner of Education, Texas Education Agency, 1701 North Congress Avenue, Austin, Texas 78701-1494

Re: Appearance of a state agency board before a legislative committee for purposes of the Open Meetings Act: Clarification of Attorney General Opinion JC-0308 (Request No. 0323-JC)

Briefs requested by February 2, 2001

For further information, please call (512) 463-2110

TRD-200100045
Susan D. Gusky
Assistant Attorney General
Office of the Attorney General
Filed: January 3, 2001

♦ ♦ ♦

Request for Opinions

RQ-0324-JC

The Honorable James Warren Smith, Jr., Frio County Attorney, 500 East San Antonio, Box 1, Pearsall, Texas 78061-3100

Re: Payment of accrued vacation time to deputy sheriffs (Request No. 0324-JC)

Briefs requested by January 20, 2001

RQ-0325-JC

The Honorable Clyde Alexander, Chair, Committee on Transportation, Texas House of Representatives, P.O. Box 2910, Austin, Texas 78768-2910

Re: Constitutionality of article 6298, V.T.C.S., which makes it unlawful for a railroad to use corporate funds to purchase its own stock (Request No. 0325-JC)

Briefs requested by January 20, 2001

RQ-0326-JC

The Honorable Thomas M. Goff, Tom Green County Attorney, 112 West Beauregard, San Angelo, Texas 76903

Re: Whether a district attorney subject to the Professional Prosecutors Act may be paid as an Air Force Reserve Officer (Request No. 0326-JC)

Briefs requested by January 19, 2001

RQ-0327-JC

The Honorable Judith Zaffirini, Chair, Human Services Committee, Texas State Senate, P.O. Box 12068, Austin, Texas 78711

Re: Whether a contractual requirement that a superintendent of schools attend executive sessions of a board of trustees violates the Open Meetings Act (Request No. 0327-JC)

Briefs requested by January 20, 2001

RQ-0328-JC

Mr. Jere M. Lawrence, Chair, Board of Regents, Texas State Technical College System, 3801 Campus Drive, Waco, Texas 76705

Re: Authority of the state auditor to audit an educational foundation created for the benefit of the Texas State Technical College (Request No. 0328-JC)

Briefs requested by January 22, 2001

For further information, please call (512) 463-2110.

TRD-200009042
Susan D. Gusky
Assistant Attorney General
Office of the Attorney General
Filed: December 27, 2000

♦ ♦ ♦

PROPOSED RULES

Before an agency may permanently adopt a new or amended section or repeal an existing section, a proposal detailing the action must be published in the ***Texas Register*** at least 30 days before action is taken. The 30-day time period gives interested persons an opportunity to review and make oral or written comments on the section. Also, in the case of substantive action, a public hearing must be granted if requested by at least 25 persons, a governmental subdivision or agency, or an association having at least 25 members.

Symbology in proposed amendments. New language added to an existing section is indicated by the text being underlined. [Brackets] and ~~strike-through~~ of text indicates deletion of existing material within a section.

TITLE 22. EXAMINING BOARDS

PART 10. TEXAS FUNERAL SERVICE COMMISSION

CHAPTER 201. LICENSING AND ENFORCEMENT--PRACTICE AND PROCEDURE

22 TAC §201.19

The Texas Funeral Service Commission proposes new §201.19, Correspondence.

The Texas Funeral Service Commission proposes a new section to establish the requirement that all correspondence to an establishment or to the funeral director in charge shall be sent to the street address of the establishment as reflected on the license application.

O.C. "Chet" Robbins, Executive Director, Texas Funeral Service Commission, has determined that for the first five-year period this section is in effect there will be no fiscal implications for state or local government as a result of enforcing or administering the section.

Mr. Robbins, Executive Director, Texas Funeral Service Commission, has determined that for each year or the first five years the public benefit will be to insure the public knows that all correspondence to an establishment or to the funeral director in charge shall be sent to the street address of the establishment as reflected on the license application. There will be no effect on small businesses. There is no anticipated economic cost to persons who are required to comply with the proposed section.

Comments on the new amendment may be submitted to O.C. "Chet" Robbins, Executive Director, Texas Funeral Service Commission, 510 South Congress Avenue, Suite 206, Austin, Texas, 78704, (512) 936-2474 or 1-888-667-4881. Comments may also be submitted electronically to crob@tfsc.state.tx.us or faxed to (512) 479-5064.

The new section is proposed under Section 651.152 of the Texas Occupation Code, as amended by Section 18 of House Bill 3516, 76th Legislature which authorizes the Commission to issue such rules and regulations as may be necessary to effect the provisions of this Section.

No other statutes, articles, or codes are affected by the new amendment.

§201.19. Correspondence.

All correspondence to an establishment or to the funeral director in charge shall be sent to the street address of the establishment as reflected on the license application.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 29, 2000.

TRD-200009101
O.C. "Chet" Robbins
Executive Director
Texas Funeral Services Commission
Earliest possible date of adoption: February 11, 2001
For further information, please call: (512) 936-2474

♦ ♦ ♦

TITLE 25. HEALTH SERVICES

PART 2. TEXAS DEPARTMENT OF MENTAL HEALTH AND MENTAL RETARDATION

CHAPTER 417. AGENCY AND FACILITY RESPONSIBILITIES

SUBCHAPTER A. STANDARD OPERATING PROCEDURES

The Texas Department of Mental Health and Mental Retardation (TDMHMR) proposes new Chapter 417, Subchapter A, §§417.1-417.6, concerning assignment and use of pooled vehicles, of Chapter 417, governing state authority responsibilities.

The proposal of new §§417.1-417.6 is made to implement Texas Government Code, §§2171.104, 2171.1045, and 2171.105, concerning fleet management.

Bill Campbell, deputy commissioner for finance and administration, has determined that for each year of the first five years the proposed new sections are in effect, enforcing or administering the sections do not have foreseeable economic implications relating to cost or revenue of the state or local government.

Sharon Hunter, director of support services, has determined that for each year of the first five years the proposed new sections are in effect, the public benefit expected is to improve operations of the department's vehicle fleet.

It is anticipated that the proposed new sections will not affect a local economy.

It is anticipated that the proposed new sections will not have an adverse economic effect on small business or micro-business because they do not place requirements on small businesses or micro-business.

Written comments on the proposal may be sent to Linda Logan, director, Policy Development, Texas Department of Mental Health and Mental Retardation, P.O. Box 12669, Austin, Texas 78711-2668, within 30 days of publication.

DIVISION 1. GENERAL REQUIREMENTS

25 TAC §§417.1 - 417.3

The new sections are proposed under the Texas Health and Safety Code, §532.015, which provides the Texas Mental Health and Mental Retardation Board with broad rulemaking authority and the Texas Government Code, §§2171.104 and 2171.1045, which the requires the department to adopt rules implementing the fleet management plan. The proposed new sections affect the Texas Government Code, §§2171.104, 2171.1045, and 2171.105.

§417.1. Purpose.

The purpose of this subchapter is to describe:

(1) the standard operating policies and procedures for state mental health facilities and state mental retardation facilities (facility);

(2) requirements and rights of facilities; and

(3) rights protections for individuals receiving services from a facility.

§417.2. Application.

This subchapter applies to the facilities of the Texas Department of Mental Health and Mental Retardation.

§417.3. Definitions.

The following words and terms when used in this subchapter shall have the following meanings, unless the context clearly indicates otherwise:

(1) Department - The Texas Department of Mental Health and Mental Retardation (TDMHMR).

(2) Facility - A state mental health facility or a state mental retardation facility funded by the TDMHMR.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 29, 2000.

TRD-200009098
Andrew Hardin
Chairman, Texas MHMR Board
Texas Department of Mental Health and Mental Retardation
Earliest possible date of adoption: February 11, 2001
For further information, please call: (512) 206-4516

♦ ♦ ♦

DIVISION 2. TRANSPORTATION

25 TAC §417.4

The new section is proposed under the Texas Health and Safety Code, §532.015, which provides the Texas Mental Health and Mental Retardation Board with broad rulemaking authority and the Texas Government Code, §§2171.104 and 2171.1045, which the requires the department to adopt rules implementing the fleet management plan. The proposed new section affects the Texas Government Code, §§2171.104, 2171.1045, and 2171.105.

§417.4. Assignment and Use of Pooled Vehicles.

(a) Each vehicle in the department's vehicle fleet pool, with the exception of vehicles assigned to field staff, is assigned to the department's motor pool and made available for check out as needed. Because of the department's organizational structure some vehicles may be permanently assigned to sub-pools within divisions and made available only to employees within those divisions.

(b) Pooled vehicles assigned on a regular or daily basis to individual administrative or executive employees, require written documentation that the assignment is critical to the needs and mission of the department. Documentation for such assignments must be maintained at each facility and sent to Central Office, Transportation, and the Office of Vehicle Fleet Management, General Services Commission.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 29, 2000.

TRD-200009099
Andrew Hardin
Chairman, Texas MHMR Board
Texas Department of Mental Health and Mental Retardation
Earliest possible date of adoption: February 11, 2001
For further information, please call: (512) 206-4516

♦ ♦ ♦

DIVISION 3. REFERENCES AND DISTRIBUTION

25 TAC §417.5, §417.6

The new sections are proposed under the Texas Health and Safety Code, §532.015, which provides the Texas Mental Health and Mental Retardation Board with broad rulemaking authority and the Texas Government Code, §§2171.104 and 2171.1045, which the requires the department to adopt rules implementing the fleet management plan. The proposed new sections affect the Texas Government Code, §§2171.104, 2171.1045, and 2171.105.

§417.5. References.

The statutes referenced in this subchapter include the Texas Government Code, §§2171.104, 2171.1045, and 2171.105.

§417.6. Distribution.

(a) This subchapter is distributed to members of the TDMHMR Board; medical director; deputy commissioners for Community Programs and Budget and Finance and the directors, State Mental Health Facilities and State Mental Retardation Facilities; and Central Office program and management staff; and

(b) This subchapter is distributed to facility CEOs who are responsible for disseminating this subchapter to their staff, as appropriate.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 29, 2000.

TRD-200009100
Andrew Hardin
Chairman, Texas MHMR Board
Texas Department of Mental Health and Mental Retardation
Earliest possible date of adoption: February 11, 2001
For further information, please call: (512) 206-4516

♦ ♦ ♦

WITHDRAWN RULES

An agency may withdraw a proposed action or the remaining effectiveness of an emergency action by filing a notice of withdrawal with the ***Texas Register***. The notice is effective immediately upon filling or 20 days after filing as specified by the agency withdrawing the action. If a proposal is not adopted or withdrawn within six months of the date of publication in the ***Texas Register***, it will automatically be withdrawn by the office of the Texas Register and a notice of the withdrawal will appear in the ***Texas Register.***

TITLE 31. NATURAL RESOURCES AND CONSERVATION

PART 20. EDWARDS AQUIFER AUTHORITY

CHAPTER 711. GROUNDWATER WITHDRAWAL PERMITS

SUBCHAPTER H. ABANDONMENT AND CANCELLATION

31 TAC §§711.196, 711.200, 711.202, 711.204

The Edwards Aquifer Authority has withdrawn from consideration for permanent adoption new §§711.196, 711.200, 711.202, and 711.204 concerning abandonment and cancellation which appeared in the September 29, 2000, issue of the *Texas Register* (25 TexReg 9886).

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009047
Gregory M. Ellis
General Manager
Edwards Aquifer Authority
Effective date: December 28, 2000
Proposal publication date: September 29, 2000
For further information, please call: (210) 222-2204

♦ ♦ ♦

SUBCHAPTER L. TRANSFERS

31 TAC §711.344, §711.346

The Edwards Aquifer Authority has withdrawn from consideration for permanent adoption new §711.344 and §711.346, concerning transfers which appeared in the September 29, 2000, issue of the *Texas Register* (25 TexReg 9900).

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009067
Gregory M. Ellis
General Manager
Edwards Aquifer Authority
Effective date: December 28, 2000
Proposal publication date: September 29, 2000
For further information, please call: (210) 222-2204

♦ ♦ ♦

ADOPTED RULES

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

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

TITLE 22. EXAMINING BOARDS

PART 12. BOARD OF VOCATIONAL NURSE EXAMINERS

CHAPTER 231. ADMINISTRATION

SUBCHAPTER A. DEFINITIONS

22 TAC §231.1

The Board of Vocational Nurse Examiners adopts the amendment to §231.1 relating to definitions without changes to the proposed text as published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11630).

The rule is amended to change any reference to Vocational Nurse Act or Article 4528c to Texas Occupations Code, Chapter 302.

No comments were received relative to the adoption of the amendment.

The amendment is adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151(b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009054
Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

SUBCHAPTER B. GENERAL PRACTICE AND PROCEDURE

22 TAC §§231.15, 231.27, 231.46-231.48

The Board of Vocational Nurse Examiners adopts the amendments to §§231.15, 231.27, and 231.46-231.48 without changes to the proposed text as published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11630).

The rules are being amended to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative to the adoption of these rules.

The amendments are adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151(b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009055
Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

SUBCHAPTER C. BOARD RULES

22 TAC §231.61

The Board of Vocational Nurse Examiners adopts an amendment to §231.61 without changes to the text as published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11631).

The rule is adopted to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative to the adoption of the rule.

The amendment is adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151(b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009056
Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 3057653

♦ ♦ ♦

CHAPTER 233. EDUCATION
SUBCHAPTER A. DEFINITIONS
22 TAC §233.1

The Board of Vocational Nurse Examiners adopts an amentdment to §233.1 without changes to the text as published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11632).

The rule is adopted to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative the adoption of this rule.

The amendment is adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151(b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009057
Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

CHAPTER 235. LICENSING
SUBCHAPTER A. APPLICATION FOR LICENSURE
22 TAC §235.1, §235.9

The Board of Vocational Nurse Examiners adopts the amendments to §235.1 and §235.9 without changes to the text as published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11632).

The rules are being amended to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative to the adoption of these rules.

The amendments are adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151(b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009058
Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

SUBCHAPTER B. BOARD REVIEW OF APPLICATION
22 TAC §§235.21-235.23

The Board of Vocational Nurse Examiners adopts the amendments to §§235.21-235.23 without changes to the text as published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11633).

The rules are adopted to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative to the adoption of these rules.

The amendments are adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151(b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009059

Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

SUBCHAPTER C. EXAMINATION

22 TAC §235.31

The Board of Vocational Nurse Examiners adopts an amendment to §235.31 without changes to the proposed text as published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11633).

The rule is adopted to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative to the adoption of this rule.

The amendment is adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151(b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009060
Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

SUBCHAPTER D. ISSUANCE OF LICENSES

22 TAC §§235.42, 235.44, 235.48

The Board of Vocational Nurse Examiners adopts §§235.42, 235.44 and 235.48 without changes to the text published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11634).

The rules are adopted to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative to the adoption of these rules.

The amendments are adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151 (b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009061
Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

CHAPTER 237. CONTINUING EDUCATION
SUBCHAPTER B. CONTINUING EDUCATION

22 TAC §237.12

The Board of Vocational Nurse Examiners adopts §237.12 without changes to the proposed text published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11634).

The rule is adopted to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative to the adoption of this rule.

The amendment is adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151 (b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000

TRD-200009062
Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

CHAPTER 239. CONTESTED CASE PROCEDURE
SUBCHAPTER A. DEFINITIONS

22 TAC §239.1

The Board of Vocational Nurse Examiners adopts §239.1 without changes to the proposed text published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11635).

The rule is being amended to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative to the adoption of this rule.

The amendment is adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151(b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009063
Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

SUBCHAPTER B. ENFORCEMENT

22 TAC §§239.11, 239.17-239.19

The Board of Vocational Nurse Examiners adopts §239.11 and §§239.17-239.19 without changes to the proposed text published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11635).

The rules are adopted to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative to the adoption of these rules.

The amendments are adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151(b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009064
Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

SUBCHAPTER C. HEARINGS PROCESS

22 TAC §239.35, §239.36

The Board of Vocational Nurse Examiners adopts §239.35 and §239.36 without changes to the proposed text published in the November 24, 2000, issue of the *Texas Register* (25 TexReg 11626).

The rules are adopted to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative to the adoption of these rules.

The amendments are adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151(b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009065
Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

CHAPTER 240. PEER REVIEW AND REPORTING

22 TAC §§240.11-240.13

The Board of Vocational Nurse Examiners §§240.11-240.13 without changes to the proposed text published in the November 24, 2000 issue of the *Texas Register* (25 TexReg 11636).

The rules are adopted to change any reference to Vocational Nurse Act or Article 4528c to Chapter 302 Texas Occupations Code.

No comments were received relative to the adoption of these rules.

The amendments are adopted under Chapter 302, Texas Occupations Code, Subchapter D, §302.151(b), which provides the Board of Vocational Nurse Examiners with the authority to make such rules and regulations as may be necessary to carry in effect the purpose of the law.

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

Filed with the Office of the Secretary of State on December 28, 2000

TRD-200009066

Mary M. Strange
Executive Director
Board of Vocational Nurse Examiners
Effective date: January 17, 2001
Proposal publication date: November 24, 2000
For further information, please call: (512) 305-7653

♦ ♦ ♦

TITLE 30. ENVIRONMENTAL QUALITY

PART 1. TEXAS NATURAL RESOURCE CONSERVATION COMMISSION

CHAPTER 101. GENERAL AIR QUALITY RULES

The Texas Natural Resource Conservation Commission (commission) adopts the *repeal* of §101.29, Emission Credit Banking and Trading. In addition, the commission adopts *new* §101.300, Definitions; §101.301, Purpose; §101.302, General Provisions; §101.303, Protocols; §101.304, Program Audits; §101.350, Definitions; §101.351, Applicability; §101.352, General Provisions; §101.353, Allocation of Allowances; §101.354, Allowance Deductions; §101.356, Allowance Banking and Trading; §101.358, Emission Monitoring and Compliance Demonstration; §101.359, Reporting; §101.360, Level of Activity Certification; §101.370, Definitions; §101.371, Purpose; §101.372, General Provisions; §101.373, Protocols; and §101.374, Program Audits. Adopted *with changes* from the proposed text as published in the May 25, 2000 issue of the *Texas Register* (25 TexReg 8137) are new §§101.300, 101.302, 101.303, 101.350 - 101.354, 101.356, 101.358 - 101.360, 101.370, 101.372 - 101.374. The repeal of §101.29 and new §§101.301, 101.304, and 101.371 are adopted *without changes* and therefore will not be republished. The repeal and new sections will be submitted to the United States Environmental Protection Agency (EPA) as a revision to the Texas state implementation plan (SIP).

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

The Houston/Galveston (HGA) ozone nonattainment area is classified as Severe-17 under the Federal Clean Air Act (FCAA) Amendments of 1990 (42 United States Code (USC), §§7401 *et seq.*), and therefore is required to attain the one-hour ozone standard of 0.12 parts per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined by Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of its Post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base-case episodes, adopted rules to achieve a 9% rate-of-progress (ROP) reduction in volatile organic compounds (VOC), and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary nitrogen oxides (NO_x) waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base-case episodes which marginally exhibited model performance in accordance with the United States Environmental Protection Agency (EPA) modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data-gathering exercise known as the COAST study. The state believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, the EPA policy regarding SIP elements and timelines went through changes. Two national programs in particular resulted in changing deadlines and requirements. The first of these programs was the Ozone Transport Assessment Group. This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in this study, and it has been concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that has impacted the SIP planning process is the revisions to the national ambient air quality standard (NAAQS) for ozone. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, the EPA proposed an interim implementation plan (IIP) that it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development timelines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, that standard would continue to apply until it is attained. The FCAA requires that HGA attain the standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998 a revision to the HGA SIP which contained the following elements in response to the EPA's guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by the FCAA, Title I, Subpart 2 to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the state eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs as well as an acceleration simulation mode equivalent motor vehicle inspection and maintenance program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory state-wide programs adopted or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon Scenario Vif); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review; and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-99 ROP plan by December 31, 2000; to perform a mid-course review by May 1, 2004; and to perform modeling of mobile source emissions using the EPA mobile source emissions model (MOBILE6), to revise the on-road mobile source budget as needed, and to submit the revised budget within 24 months of the model's release. In addition, if a conformity analysis is to be performed between 12 months and 24 months after the MOBILE6 release, the state will revise the motor vehicle emissions budget (MVEB) so that the conformity analysis and the SIP MVEB are calculated on the same basis.

In order for the state to have an approvable attainment demonstration, the EPA has indicated that the state must adopt those strategies modeled in the November 1999 submittal and then adopt sufficient controls to close the remaining gap in NO_x emissions. The modeling and other analysis supporting these rules and the HGA SIP indicate a gap of an additional 88.8 tons per day (tpd) of NO_x reductions is necessary for an approvable attainment demonstration. The predicted emission reductions from these rules are necessary to successfully demonstrate attainment.

The emission reduction requirements included as part of this SIP revision represent substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, have worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area have formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

This rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000 and planned to be submitted to the EPA by December 31, 2000.

The amount of NO_x reductions required for the area to attain the ozone NAAQS has 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 reduction strategies. The FCAA, 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 oversight committee. Commission staff have continued to improve the air quality modeling technology and refine emission inventory data. Numerous emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources, on-road and non-road mobile sources, and area sources were analyzed in multiple iterations of modeling, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling and other analysis submitted for public hearing and comment concurrently with the HGA SIP show that a significant amount of NO_x reductions practicably achievable are necessary from ozone control strategies in order for the HGA nonattainment area to achieve the ozone NAAQS by 2007, including reductions from surrounding counties included in the HGA consolidated metropolitan statistical area (CMSA).

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies. At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The current SIP revision contains rules, enforceable commitments, photochemical modeling analyses, and calculation of the remaining NO_x reductions required to reach attainment (gap calculation) in support of the HGA ozone attainment demonstration. In addition, this SIP contains post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contains enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit a mid-course review.

The HGA ozone nonattainment area will need to ultimately reduce NO_x more than 750 tons per day to reach attainment with the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of the banking rules will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area.

The emissions banking and trading program has been designed to offer flexibility in generating and using emission reduction credits (ERCs), mobile emission reduction credits (MERCs), discrete emission reduction credits (DERCs), and mobile discrete emission reduction credits (MDERCs). Flexibility has been built into the rules to create incentives for the early or permanent retirement of VOC and NO_x emissions. The intent of the rules is to also streamline the emissions banking and trading program by combining the stationary credits with mobile credits to achieve continuity within the banking programs.

New §§101.300 - 101.304 are grouped into Subchapter H, Division 1, Emission Credit Banking and Trading. The rules consolidate the requirements for generating, using, banking, and trading ERCs and MERCs. The revisions to the rules are intended to achieve consistency between the rules governing the use of ERCs/MERCs and DERCs and MDERCs. The revisions to the rules also address concerns raised by the EPA regarding current rules on how reductions are calculated as surplus and to ensure that emission reductions are not double-counted, that is, not banked as credits and relied upon as SIP reductions. These sections would reduce the life of ERCs/MERCs after January 2, 2001 to five years to restrict the use of ERCs/MERCs to meet current environmental conditions. The rules require the registration of emission reductions as ERCs/MERCs within 180 days of the actual reduction and add recordkeeping requirements to sources generating or using ERCs/MERCs.

New §§101.350 - 101.354, 101.356, and 101.358 - 101.360 are grouped into Subchapter H, Division 3, Mass Emissions Cap and Trade Program. These sections implement a mandatory annual NO_x emission cap on all existing stationary facilities located in the HGA area that emit ten tons or more per year (tpy) of NO_x and that have SIP emission requirements in 30 TAC §117.106, Emission Specifications for Attainment Demonstrations, §117.206, Emission Specifications for Attainment Demonstrations, and §117.475, Emission Specifications. The cap would be enforced by the allocation, trading, and banking of allowances. An allowance is the equivalent of one ton of NO_x emissions. NO_x is a precursor gas that reacts with VOCs in the presence of sunlight to form ground-level ozone. This NO_x cap would be established at levels demonstrated as necessary to allow HGA to attain the NAAQS for ozone. The cap will be implemented on January 1, 2002 at historical emission levels, with mandatory reductions increasing over time until achieving the final cap by April 1, 2007. These sections also require all new or modified sources in HGA to obtain unused allowances from other sources already participating under the cap to offset any increased NO_x emissions.

At this time, the commission will cap only those sources located in the eight-county HGA area. The commission will continue to evaluate ozone control strategies and may extend the cap and trade program to include other regions of the state in future rulemaking.

New §§101.370 - 101.374 are grouped into Subchapter H, Division 4, Discrete Emission Credit Banking and Trading. The rules consolidate the requirements for generating, using, banking, and trading DERCs and MDERCs. The revisions to the rules are intended to achieve consistency between the rules governing the use of ERCs/MERCs and DERCs/MDERCs. The revisions to the rules also address concerns raised by the EPA regarding current rules on how reductions are calculated as surplus and to ensure that emission reductions are not double-counted, that is, not banked as credits and relied upon as SIP reductions.

SECTION BY SECTION DISCUSSION

DIVISION 1

New §101.300 contains the definitions to be used within Subchapter H, Emissions Credit Banking and Trading, Division 1, Emission Credit Banking and Trading. The definitions of "Activity," "Actual emissions," "Area Source," "Certified," "Emission Reduction Credit (ERC)," "Emission Reduction Strategy," "Generator," "Permanent," "Quantifiable," and "Shutdown" were defined in §101.29 and are transferred unchanged to §101.300.

The following definitions have been moved from §101.29 to §101.300 and amended. "Applicable emission point" is revised to refer to the emission point generating an emission reduction or using an emission credit. This revision will allow for consistency with the use of terms throughout the adopted rule language. The definition of "Baseline" is amended to limit the emissions occurring prior to a reduction strategy to levels not to exceed the most recent level of emissions reported in the emission inventory used for SIP determinations. The definition of "Baseline activity" is amended to describe a source's actual level of activity based on actual data averaged over any consecutive two calendar year periods during the most recent year of emissions inventory used for SIP determinations or subsequent year(s). For sources in existence less than 24 months or not having two complete calendar years of data, a shorter time period, not less than 12 months, may be considered by the executive director. The definition of "Baseline emission rate" is amended to refer to the source's rate of emissions per unit of activity during the baseline activity period. The definition of "Curtailment" is amended to mean a reduction in activity level at any stationary or mobile source. The definition of "Mobile emission reduction credit (MERC or mobile credit)" is amended to be a credit representing the amount of emission reductions from a mobile source strategy. These emission reductions are voluntary and must be in addition to compliance with requirements of state and federal regulations. MERCs are any enforceable, permanent, and quantifiable emission reduction (exhaust and/or evaporative) generated by a mobile source, which has been banked in accordance with the rules of the commission. MERCs can be banked, purchased, traded, and sold to meet clean air mandates for specified air programs and MERCS may be applied to the emission reduction obligations of another air quality source or to air quality attainment goals. The definition was revised to clarify that MERCs are expressed in terms of tons per year. "Most stringent allowable emissions level" is amended to include a reference to state emission limits. The definition of "Ozone season" is revised to be the portion of the year when ozone monitoring is required to occur in a specific geographic area. This amendment removes specific references to dates for a given nonattainment area. "Protocol" is amended to refer to replicable and workable methods for mobile, stationary, or area sources. "Real reduction" means a reduction in actual emissions as opposed to a reduction in allowable emissions. "Surplus" is amended to refer to an emission reduction which is not otherwise required of a source by any state or federal law, regulation, or agreed order and is beyond the emissions level utilized for SIP determinations. "User" is amended to refer to the owner or operator which acquires and uses emission credits to meet a regulatory requirement, demonstrate compliance, or offset an emission increase.

The following new definitions are added to §101.300. "Baseline emissions" is defined as the source's total actual emissions based on the baseline activity and emission rate. An "Emission credit" is defined as a credible emission reduction such as an "Emission reduction credit" or "Mobile emission reduction credit." A new definition of "Emission reduction" is added as an actual reduction of emissions from a stationary or mobile source. "Mobile emission baseline" is defined as a mobile source reduction that occurs prior to a mobile emission reduction strategy, considering all limitations required by applicable state and federal regulations. A valid mobile emission baseline could be calculated by either use of measured emissions of an appropriately sized sample of the participating mobile sources using an approved EPA test procedure or by using estimated emissions of the participating mobile sources using the most recent edition of the EPA's mobile emissions factor model or other applicable model. The baseline cannot be higher than the emissions that are estimated in the SIP for that vehicle. "Mobile source" is defined as on-road (highway) vehicles (e.g., automobiles, trucks, and motorcycles) and non-road vehicles (e.g., trains, airplanes, agricultural equipments, industrial equipment, construction vehicles, off-road motorcycles, and marine vessels). A "Mobile source baseline activity" is defined as the mobile source's level of activity during the applicable mobile source baseline year. "Mobile source baseline emissions" is defined as the mobile source's total emissions based on the product of mobile source baseline activity and mobile source baseline emission rate. "Source" is a point of origin of air contaminants, whether privately or publicly owned or operated. Upon request of a source owner, the executive director shall determine whether multiple processes emitting air contaminants from a single point of emission will be treated as a single source or as multiple sources.

New §101.301 states that the purpose of Division 1 is to allow an operator of a source to generate and use emission credits. The wording of this section has been revised from the previous language in §101.29 to refer to both ERCs and MERCs as emission credits, unless the rule language specifically refers to only one of these emission credits. This new section also states that participation in the program is voluntary.

New §101.302 contains the general provisions for the Emission Credit and Trading Program (Division 1). The wording of this section has been revised from the previous language in §101.29 to refer to both ERCs and MERCs as emission credits, unless the rule language refers to only one of these emission credits. Language was added to clarify that the EPA must also grant approval before a reduction of one pollutant may be used to meet the requirements of another pollutant. The certification requirements of an emission credit have been revised to only allow credits which have occurred after the most recent year of emissions inventory used for SIP determinations and to require the source's annual emissions to have been represented in the emissions inventory of the most recent year of emissions inventory used for SIP determinations prior to the submittal of the emission credit application. Rule language has been added to this division which would not allow emission credits which are certified as ERCs or MERCs to be recertified as emission credits under any other division within Subchapter H. The rules associated with eligible sources have been changed to be consistent with the previous language of §101.29 for discrete emission credits. The changes allow for stationary sources (including area sources), mobile sources, and stationary sources (including area sources) or mobile sources associated with agencies under §101.30 to be eligible to generate emission credits. Effective January 2, 2001, the life of an emission credit would be revised to be available for use for 60 months from the date of the reduction except to the extent regulatory changes reduce or invalidate the reduction. ERCs, for which an administratively complete application has been received prior to January 2, 2001, would continue to be available for 120 months from the date of the reduction except to the extent regulatory changes reduce or invalidate the reduction. The geographic scope would remain the same as previously stated in §101.29, except the new rule language allows for the trading of emission credits achieved in the county, state, or nation provided the applicant can demonstrate an improvement to the air quality in the county of use and the demonstration is approved by the executive director and the EPA. To be consistent with the previous language of §101.29, rule language is added which allows for the possibility of the trading of emission credits to be discontinued by the executive director, with commission approval, as a remedy for problems caused by localized trading of emission credits. The rules regarding the registry were revised from the proposal to state that a unique number is assigned to certificates and not to individual tons of ERCs or MERCs. Recordkeeping requirements have been revised to require users to maintain a copy of all notices and information submitted to the registry for at least two years after the beginning of the use period along with the name, emission point number (EPN), and facility identification number (FIN) of each unit using emission credits, the amount of emission credits being used, and the specific identification number of the emission credits being used. The rule language concerning public information has been changed to be consistent with the discrete emission reduction requirements language previously located in §101.29(d)(1)(L). All information submitted with a notice or report regarding the nature and quantity of emissions associated with the use or generation of an emission credit is public information and will not be considered confidential. All non-confidential notices and information regarding generation, use, and availability of emission credits may be obtained from the Office of Permitting, Remediation, and Registration (OPRR). In addition, rule language is adopted which allows the executive director to prohibit a company from participating in the program if the company has violated or abused the program.

New §101.303 outlines the required protocols of generating, calculating, certifying and registering, using, and transferring emission credits. This section requires emission credits to be determined based on established EPA protocols when available, actual monitoring results, or calculated using good engineering practices. The procedures previously in §101.29 regarding the various means for generating emission credits are transferred unchanged to this section. The rule addresses procedures for calculating MERCs although most mobile source strategies will likely only qualify for MDERCs. MERCs would be available for mobile source strategies that are ongoing, creating the same amount of mobile reduction each year. Language is added which prohibits the generation of credits if the emissions have been transferred to another unit. This additional language eliminates the potential for a company to shut down a unit to generate emission credits, and then alter the operation of another piece of equipment to take the place of the shut down unit which would increase the emissions at the altered unit. The new rules require companies to apply for emission credits within 180 days of generation, except that those sources that have implemented strategies prior to the effective date of this rule will be given until June 1, 2001 to apply. New language has been added to the rules specifying the information which must be submitted. The information, which is to be submitted on the EC-1 Form, includes the information necessary for the executive director to review the application in accordance with the adopted rules and to properly administer the program. Language was added to clarify that the most stringent emission rate would be determined by also reviewing local, state, and federal statutory requirements. Applicants will be notified in writing if the executive director denies the application. The new rule language specifically states the commission's accepted practice that emissions credits will be determined and certified to the nearest tenth of a ton per year. As was previously stated in §101.29, the new section states that emission credits are determined and certified by using the EPA methodologies, monitoring results, or otherwise good engineering practices, and all emission credits are deposited in the registry and reported as available credits until they are used, withdrawn, or expired. As was previously contained in §101.29, the new section would list the mechanisms which can be used to make emission credits enforceable. Rule language has been added which lists the OPCRE-1 Form as an enforceable mechanism to establish new emission limits for grandfathered sources when applying for emission credits. Rule language has also been added to make MERCs enforceable by registering them on a form approved by the executive director or by an agreed order that will set new maximum allowable mobile source emission limits which are not required to be implemented by a rule. The language would limit the use of emission credits if there are permits under the same account number which contain a condition or conditions which preclude such use. As was previously allowed in §101.29, the new section allows ERCs to be used for offsets, mitigation offsets, and alternative compliance with reasonably available control technology (RACT) or SIP requirements. As has been the commission's practice, the language allows the use of emission credits for netting only by the original applicant if the emission credits have not been previously sold or otherwise used and also allows the use of emission credits for other provisions within the guidelines of local, state, and federal laws. The section allows MERCs to be used as offsets, mitigation offsets, alternative compliance with RACT or SIP requirements, compliance with fleet requirements as allowed by the Texas Clean Fleet Program Requirements for Motor Vehicle Fleets, or other provisions as allowed within the guidelines of local, state, and federal laws. The requirements for compliance with §117.570, Use of Emissions Credits for Compliance, except for the equations for determining 30-day rolling average emission limits, are changed to allow for emission reduction calculations in accordance with the methodology of this new division. These revisions replace the former equations previously located in §117.570. The equations for calculating 30-day rolling average emission limits have been relocated from §117.570 to this section. The procedure for notifying the commission of the intent to use emission credits in accordance with 30 TAC Chapter 114, Control of Air Pollution from Motor Vehicles, §115.950, Emissions Trading, and §117.570 and any other commission rules is revised to require the submittal of the EC-3 Form. The timelines for the review of this submittal have been removed from the rule language, revised, and included in the Emission Banking and Trading Program Technical Guidance Package. As previously required in §101.29, an additional 10% of emission credits will be retired as an environmental contribution. The section states that the user of credits shall submit an EC-3 Form along with the emission credit certificates when using the credits as offsets in accordance with 30 TAC Chapter 116, Division 7, Emission Reductions: Offsets, or for alternative compliance with 30 TAC Chapters 114, 115, or 117. The procedure for transfer is revised to require emission credit certificate owners to submit an EC-4 Form, including the sale price, to the agency prior to the transfer. Transfers would only be considered final after the executive director has completed the transaction. This is a change to the previous language in §101.29, which requires notification within 30 days of the transfer. As previously stated in §101.29, the new section states that the emission credits may be withdrawn from the registry at any time prior to the expiration date of the credit, and that emission reductions which have been certified as credits and have expired may still be used by the original owner for netting in accordance with §116.150. The section requires applicants needing offsets for a new source review permit to identify the credits at the time of permit issuance and to provide the original emission credit certificate prior to operation. It should be noted that emission credits will be evaluated to ensure that they are surplus at the time of use. The section requires that any other uses of credits be approved by the executive director prior to commencement of the intended use. Rule language added allows an applicant to file a motion for reconsideration with the executive director within 60 days of denial of use of emission credits.

New §101.304 requires the executive director to perform an audit of the emission reduction program within three years of the effective date of the new division and every three years thereafter. The audit would evaluate the timing of credit generation and use, the impact of the program on the SIP, availability and cost of credits, compliance by participants, and any other elements chosen by the executive director.

DIVISION 3

New §101.350 contains the definitions to be used with Subchapter H, Emissions Credit Banking and Trading, Division 3, Mass Emission Cap and Trade Program. In response to comments received, the definition of "Allowance" has been modified from the proposal and is now defined as the authorization to emit one ton of NO_x during a control period as expressed in tenths of a ton. The definition of "Authorized account representative" is the person authorized, in writing, to transfer and otherwise manage allowances. The definition of "Banked allowance" is an allowance which is not used to reconcile emissions in the designated year of allocation, but which is carried forward for up to one-year and noted in the compliance or broker account as banked. The definition of "Broker" is a person not required to participate in the requirements of this division who opens an account under this division for the purpose of banking and trading allowances. The definition of "Broker account" is the account where allowances held by a broker are recorded. Allowances held in a broker account may not be used to satisfy compliance requirements for this division. The definition of "Compliance account" is the account where allowances held by a facility or multiple facilities at a single site are recorded for the purposes of meeting the requirements of this division. This definition was modified from the proposal to clearly identify the intent when referring to a piece of equipment that is emitting NO_x. It was necessary to add language concerning a single site to clarify the correspondence of a single compliance account to a single site. The reference to sources not under common ownership or control was deleted as it was unnecessary and ambiguous. Separate sites with facilities subject to the cap and trade program will automatically be assigned separate compliance accounts unless a single property designation is obtained. The definition of "Control period" is the 12-month period beginning January 1 and ending December 31 of each year. The initial control period would begin January 1, 2002. The definition of "Level of activity" is the amount of activity at a source measured in terms of production, fuel use, raw materials input, or other similar units that have a direct correlation with the economic output and emission rate of the source (i.e., mass emitted per unit of activity). The definition of "Person"includes, for the purpose of issuance of allowances under this division, an individual, a partnership of two or more persons having a joint or common interest, a mutual or cooperative association, and a corporation. The new section refers to the following existing definitions: "Houston/Galveston (HGA) ozone nonattainment area" as defined in §101.1; and "Site" as defined in §122.10, General Definitions. The definition of "Site" was added since publication of the proposal. The definition of "Source" was deleted from the adoption because the use of the term "facility" is more appropriate when describing pieces of equipment emitting NO_x.

New §101.351 states that the requirements of Division 3 apply to all stationary facilities which emit NO_x in the HGA nonattainment area subject to the emission specifications under §§117.106, 117.206, and 117.475 and that have a design capacity to emit ten tons or more per year of NO_x. The term facility has been substituted for source to identify specific equipment emitting NO_x. The commission intends to propose a revision to this section to clarify that the cap and trade rules apply to all facilities subject to Chapter 117 at sites where these facilities collectively have a design capacity to emit ten tons or more per year of NO_x. This clarification reflects the original intent of the commission and the commission will propose this revision to allow for notice and comment on the clarification shortly after adoption of these rules.

New §101.352 states that allowances may only be used as described in Division 3 and cannot be used to meet or exceed the limitations of any annual emission limitation authorized under Chapter 116, Subchapter B, any applicable rule or law, or for netting purposes to avoid the applicability of federal and state new source review (NSR) requirements. The new section requires that each site shall hold a quantity of allowances in its compliance account on February 1 equal to or greater than the total emissions of NO_x emitted from each facility subject to Chapter 117 for the control period just ending. The cap and trade program begins January 1, 2002. Beginning February 1, 2003 and no later than every February 1 following the end of every subsequent control period, each site is required to hold the amount of allowances it used in the previous year's control period. The new section allows unused allowances to be banked as ERCs provided that an enforceable and permanent reduction of annual allowances is approved by the executive director, and all applicable requirements of Division 1 of Chapter 101, Subchapter H are met. The section does not allow unused allowances to be banked as DERCs. The new section states that allowances may be simultaneously used to satisfy the correlating one-to-one portion of offset requirements for new or modified facilities subject to federal nonattainment NSR requirements as provided in Chapter 116, Division 7. However, allowances may not be used for netting under Chapter 116, Subchapter B, Divisions 5 or 6. This language has been changed from the proposal for clarity. The new section states that all allowances would be allocated, transferred, or used in tenths of a ton. This is a change from the proposal which required the banking and trading of allowances in whole tons. This change was made because the cost of allowances could cause significant financial loss if they were rounded to the nearest ton. The meaning of allowance still means the authorization to emit one ton of NO_x per year. One compliance account shall be used for multiple sources located at the same site and under common ownership or control. The new section states that an allowance would not constitute a security or a property right. The commission will maintain a registry of the allowances in each compliance account. The registry will not contain proprietary information. Requests for information identified as proprietary when submitted to the agency would be subject to the procedures set out in the Texas Public Information Act.

New §101.353 describes how allowances will be allocated to individual facilities. This section has been revised since proposal for the adoption for clarity, to change the reduction schedule, and to revise the amount of necessary reductions. Initially, for any facility operating prior to January 1, 1997, allowances will be based on its actual level of activity from 1997, 1998, and 1999 multiplied by the higher of the facility's actual emission factors from 1997, 1998, and 1999 (not to exceed any applicable federal or state regulation, rule, or permit limit) or the facility's emission factor listed in Chapter 117. For a facility not operating prior to January 1, 1997 and which has submitted, under Chapter 116, Control of Air Pollution by Permits for New Construction or Modification, an application which the executive director has determined to be administratively complete before January 2, 2001 or has qualified for a permit by rule under Chapter 106, Permits by Rule, and has commenced construction before January 2, 2001, allowances will be equal to the facility's level of activity as authorized by the executive director, (until such time that two complete consecutive calendar years of actual level of activity data is available), multiplied by the higher of the facility's authorized emission factor (until such time an emission factor averaged over the most recent two consecutive calendar years is available, not to exceed any applicable federal or state regulation, rule, or permit limit) or the facility's emission factor listed in Chapter 117. For a facility using alternative emission specifications as allowed in §§117.106(c)(2), 117.206(c)(17), or 117.475(c)(3) beginning allowances will be calculated using the lowest level of activity as determined by the facility's 1997 through 1999 level of activity average, two complete calendar years of average level of activity subsequent to 1997, or a level of activity limited by an enforceable limit or commitment multiplied by the higher of the facility's authorized emission factor (until such time an emission factor averaged over the most recent two consecutive calendar years is available, not to exceed any applicable federal or state regulation, rule, or permit limit) or the facility's emission factor listed in Chapter 117. The purpose for using a two- or three-year average, when available, is to limit the effect of a year in which the activity level was uncharacteristically low or high for a facility. The purpose for using the higher of the facility's actual or allowable emission factor or its emission factor as listed in Chapter 117 is to prevent penalizing those facilities already emitting or authorized to emit at levels equal to or lower than the requirements in Chapter 117.

For all boilers, auxiliary steam boilers, and stationary gas turbines within an electric power generating system as defined in §117.10, Definitions, allowances will be reduced by 47% of the required reductions in Chapter 117 beginning January 1, 2003. Beginning April 1, 2004, allowances for boilers, auxiliary steam boilers, and stationary gas turbines will be reduced by 95% of the required reduction. Beginning April 1, 2007 and for all subsequent control periods allowances for boilers, auxiliary steam boilers, and stationary gas turbines will be reduced by 100% of the required reductions.

For all other sources, allowances will be reduced by 44% of the required reductions in Chapter 117 beginning January 1, 2004. Beginning April 1, 2005, allowances for boilers, auxiliary steam boilers, and stationary gas turbines will be reduced by 89% of the required reduction. Beginning April 1, 2007 and for all subsequent control periods allowances will be reduced by 100% of the required reductions. The commission believes that this revised compliance schedule facilitates a determination at the mid-course review by May 1, 2004 to ensure that the final 5% of the reductions from boilers, auxiliary steam boilers, and stationary gas turbines within an electric power generating system, as defined in §117.10, and the final 11% of the reductions from other sources are necessary or sufficient for attainment of the ozone standard.

The section states that any new or modified facility will not be allocated any allowances if that facility has submitted, under Chapter 116, Control of Air Pollution by Permits for New Construction or Modification, an application which the executive director has determined to be administratively complete on or after January 2, 2001 or has qualified for a permit by rule under Chapter 106, Permits by Rule, and has commenced construction on or after January 2, 2001. These new or modified facilities will be required to obtain allowances an on annual basis from other facilities already participating in the cap and trade program or by obtaining DERCs or MDERCs. This requirement applies only to those facilities identified in §101.351 relating to applicability. The section states that if a facility emits more NO_x than was held in the compliance account on January 31 following the control period, allowances for the next control period will be reduced by the amount equal to the emission exceeding the compliance account plus an additional 10%. Based on comments received, language was added from the proposal to clarify that this section does not preclude additional enforcement action by the executive director. The section states that allowances would be allocated by January 1 of each control period, beginning in 2002, that the annual allocation of allowances may be adjusted by the executive director for any new or existing SIP requirement, and that allowances may be added or subtracted from compliance accounts after reviewing the reports required in §101.359. The section allows the executive director to deviate from the allocation methodology in extenuating circumstances. The commission added language stating that owners or operators of facilities seeking deviations from the allocation methodology of this section due to extenuating circumstances must apply to the executive director no later than June 1, 2001. Based on comments received, the commission added language stating that allowances allocated based on historical activity levels will continue to be allocated despite subsequent shutdowns or reductions in activity levels.

New §101.354 describes how allowances will be subtracted out of compliance accounts. The section states that allowances are deducted from a site's compliance account in tenths of tons based on the facility's level of activity during a control period and multiplied by the facility's emission factor during the control period. This change from the proposal, which used whole tons, was based on comments. The commission added language which states that another method to determine the number of allowances to be deducted from a compliance account can be used in lieu of the method mentioned above as determined by the executive director. This was added for cases where continuous monitoring data, stack sampling, or other methods might provide better results when determining a facility's actual emissions. The commission added language which requires the executive director to deduct the most recently allocated allowances before deducting banked allowances. This language was added to minimize the possible effect on the emission cap by the accumulation of allowances. The commission added language that states that allowances allocated based on authorized levels of activity and not on historical levels of activity may only be used by the facility for which they were allocated and may not be used by other facilities at the same site during the same control period. Allowances allocated based on authorized levels of activity are intended to allow new and modified facilities an authorization to emit until such time as two complete consecutive calendar years of data is available. These allowances are not intended to provide additional flexibility to existing facilities at the site. The section states that a facility shall hold a quantity of allowances equal to or greater than its actual NO_x emissions by February 1 for the preceding control period.

The new §101.356 describes how allowances may be traded and banked. Allowances may generally be banked for future use or traded during the control period for which they are allocated or the following control period. Any allowance not used for compliance may be banked or traded for use in the following control period, with the exception of unused allowances allocated in variables (2)(B) and (3)(B) in Figure 30 TAC §101.353(a). The section states that allowances that aren't expired or used could be traded at any time after they have been allocated, again with the exception of allowances allocated in variables (2)(B) and (3)(B) in Figure 30 TAC §101.353(a). Only authorized account representatives may trade allowances. Trade requests would be made through the submittal of a completed ECT-2 Form. As part of the application, the account representative shall report the price paid per allowance and shall submit the ECT-2 Form within 15 days prior to be deposited into the transferee's broker or compliance account. Trades would be completed through the executive director and would be considered complete when the executive director issues a letter finalizing the trade. This section would allow for the use of discrete emission credits in accordance with Chapter 101, Subchapter H, Division 4 in place of allowances for compliance with Division 3. This section has been revised based on comments to clarify how DERCs and MDERCs may be used. The section has been revised to state that MDERCs may be used in lieu of allowances on a one-to-one ratio. DERCs generated prior to January 1, 2005 may be used in lieu of allowances at a one-to-one ratio prior to January 1, 2005. DERCs generated prior to January 1, 2005 may be used in lieu of allowances at a ten-to-one ratio after January 1, 2005. DERCs generated on or after January 1, 2005 may be used in lieu of allowances at a one-to-one ratio on or after January 1, 2005. In addition, no more than 10,000 DERCs will be allowed to be used in the entire HGA nonattainment area per year on or after January 1, 2005. The executive director will develop guidance to determine how the 10,000 DERCs will be distributed among all applicants requesting their use. Language was added to clarify that the 10% environmental contribution and the 5% compliance margin of Division 4 do not apply to the use of DERCs and MDERCs in lieu of allowances. The commission has also reduced the 45 day requirement to submit a notice of intent to use to 30 days. In response to comments the commission is evaluating the use of ERCs in lieu of allowances and may consider future rulemaking. The section was also revised, based on comments, to require an audit of the cap and trade program every three years. The audit will evaluate the program, its success and failures, its impact on the SIP, and any other pertinent information.

New §101.358 states that if monitoring is required of a facility under a federal or state program, that monitoring or other data shall be used to determine actual NO_x emissions. Facilities not required to monitor shall calculate actual NO_x emissions using generally accepted engineering practices, including calculation methodologies in general use and accepted in NSR permitting.

New §101.359 states that facilities shall submit by March 31 a completed ECT-1 Form detailing the amount of actual NO_x emission for the preceding control period and shall include the methods used in determining the NO_x emissions and a summary of all final trades.

New §101.360 states that all facilities required to participate in the cap and trade program would be required to submit a completed ECT-3 Form certifying their historical level of activity by June 30, 2001. This section was revised to clarify that the level of activity must be submitted not only for facilities with three complete years of historical data from 1997 through 1999, but also for the other facilities that will receive allowances based on their authorized activity levels and subsequently, their two years of actual data. This information will be used to calculate each facility's allocations.

DIVISION 4

New §101.370 contains the definitions to be used within Subchapter H, Emissions Credit Banking and Trading, Division 4, Discrete Emission Credit Banking and Trading. The definitions of "Activity," "Actual emissions," "Area Source," "Certified," "Emission Reduction Strategy," "Generator," "Permanent," "Quantifiable," "Shutdown," and "Use period" were defined in §101.29 and were transferred unchanged to §101.370.

The following definitions were moved from §101.29 to §101.370 and amended. "Applicable emission point" is revised to refer to the emission point generating an emission reduction or using an emission credit. This revision allows for consistency with the use of terms throughout the rule language. The definition of "Baseline" is amended to limit the emissions occurring prior to a reduction strategy to levels not to exceed the most recent level of emissions reported in the emission inventory used for SIP determinations. The definition of "Baseline activity" is amended to describe a source's actual level of activity based on actual data averaged over any consecutive two calendar year period during the most recent year of emissions inventory used for SIP determinations or subsequent year(s). For sources in existence less than 24 months or not having two complete calendar years of data, a shorter time period, not less than 12 months, may be considered by the executive director. The definition of "Baseline emission rate" is amended to refer to the source's rate of emissions per unit of activity during the baseline activity period. The definition of "Curtailment" is amended to mean a reduction in activity level at any stationary or mobile source. The definition of "Discrete emission reduction credit" is revised to be a credible emission reduction that is created during a generation period, quantified after the period in which emission reductions are made, and expressed in tons. This change provides consistency with the new terms and definitions of the adopted rules. The definition of "Ozone season" is revised to the portion of the year when ozone monitoring is federally required to occur in a specific geographic area. "Protocol" is amended to refer to replicable and workable methods for mobile and stationary sources. The definition of "Real reduction" means a reduction in actual emissions as opposed to a reduction in allowable emissions. "Surplus" is amended to refer to an emission reduction which is not otherwise required of a source by any state or federal law, regulation, or agreed order and is beyond the emissions level utilized for SIP determinations. "User" is amended to refer to the owner or operator which acquires and uses emission credits to meet a regulatory requirement, demonstrate compliance, or offset an emission increase. "Use strategy" is revised to refer to the use of "emission credits" which is more consistent with the terms in the new rules.

The following new definitions are added to §101.370. "Baseline emissions" is defined as the source's total actual emissions based on the baseline activity and baseline emission rate. A "Discrete emission credit" is defined as a credible emission reduction such as a "Discrete emission reduction credit" or "Mobile discrete emission reduction credit." A definition of "Emission reduction" is added as an actual reduction of emissions from a stationary or mobile area source. The "Generation period" is defined as the discrete period of time, not exceeding 12 months, over which a discrete emission reduction credit is created. The definition of "Level of Activity" was added in response to comments. The definition states that the level of activity is the amount of activity at a source measured in terms of production, fuel use, raw material input, or other similar units that have a direct correlation with the economic output and emission rate of the source (i.e., mass emitted per unit of activity). A "Mobile discrete emission reduction credit (MDERC or discrete mobile credit)" is defined as a credit that is surplus, generated by a mobile source strategy. It is a creditable emission reduction that is created during a generation period, quantified after the period in which emissions reductions are made, and expressed in tons. "Mobile emissions baseline" is defined as mobile emissions which occur prior to a mobile emission reduction strategy, considering all limitations required by applicable state and federal regulations. A valid mobile emission baseline could be calculated by either using measured emissions of an appropriately-sized sample of the participating mobile sources using an approved EPA test procedure or by using estimated emissions of the participating mobile sources using the most recent edition of the EPA's mobile emissions factor model or other applicable model. The baseline cannot be higher than the emissions which are estimated in the SIP for that vehicle. "Mobile source baseline activity" is defined as the mobile source's level of activity during the applicable mobile source baseline year. The definition for "Mobile source baseline emissions" is a source's total actual mobile source emissions based on the mobile source activity and the mobile source emissions rate. "Most stringent allowable emissions rate" is the emission rate of a source, considering all limitations required by applicable local, state, and federal regulations. The term "Strategy activity" is the source's level of activity during the discrete emission reduction generation period and "Strategy emission rate" is the source's emission rate during the discrete emission reduction generation period. "Source" is a point of origin of air contaminants, whether privately or publically owned or operated. Upon request of a source owner, the executive director shall determine whether multiple processes emitting air contaminants from a single point of emission will be treated as a single source or multiple sources.

New §101.371 states that the purpose of Division 4 is to allow an operator of a source to generate and use discrete emission credits. The wording of this section is revised from the previous language in §101.29 to refer to both DERCs and MDERCs as discrete emission credits, unless the rule language refers to specifically only one of these discrete emission credits. This new section also states that participation in the program is voluntary.

New §101.372 contains the general provisions for the Discrete Emission Credit and Trading Program. The wording of this section is revised from the previous language in §101.29 to refer to both DERCs and MDERCs as emission credits, unless the rule language refers to only one of these discrete emission credits. The section specifies to which pollutants the program will apply and the included pollutants are unchanged from those previously in §101.29. Language was added to clarify that the EPA must also grant approval before a reduction of one pollutant may be used to meet the requirements of another pollutant. The section states that DERCs and MDERCs must be real, quantifiable, and surplus. The certification requirements of a discrete emission credit would be revised to only allow credits which have occurred after the most recent year of emissions inventory used for SIP determinations and to require the source's annual emissions prior to the submittal of the emission credit application to have been represented in the emissions inventory of the most recent year of emissions inventory used for SIP determinations. Rule language is added which prohibits emission credits certified as DERCs or MDERCs from being recertified as emission credits under any other division within Subchapter H. The section allows for stationary sources (including area sources), mobile sources, and stationary sources (including area sources) or mobile sources associated with agencies under §101.30 to be eligible to generate and use emission credits. The rule language will allow DERCs and MDERCs to be available for use after the executive director has received a notice of generation and the discrete emission credits have been reviewed and deemed creditable. This is a change from previous procedures where emission credits were placed in the registry upon receipt of the notice of generation and were not reviewed for credibility until a notice of intent to use was received by the executive director. This change will allow for the emission reduction program and the discrete emission reduction program to operate on a more consistent basis. The section states that DERCs and MDERCs may be used anytime after certification and that they do not expire. The geographic scope will remain the same as previously stated in §101.29, except the new rule language will allow for the trading and use of emission credits generated in other counties, states, or nations provided that a demonstration has been made and approved by the executive director and the EPA showing that the reduction in the area where the credit was generated causes an improvement in air quality in the county where the credit is used. As previously stated in §101.29, the trading of discrete emission credits may be discontinued by the executive director with commission approval, and for areas having an ozone season less than 12 months, discrete emission credits generated outside the ozone season may not be used during the ozone season. The commission will maintain a registry that lists all discrete emission credits available or used. The section requires the generator and user of discrete emission credits to maintain a copy of records for a minimum of five years regarding the generation and use of credits. The records shall include at a minimum the name, emission point, and facility identification number of each source using discrete reduction credits, the amount of discrete reduction credits being used, and the specific identification number of the credit being used. As previously stated in §101.29, all information submitted with any application to generate or use discrete emission credits may not be submitted as confidential and discrete emission credits do not constitute a property right. The rules state that the executive director has the authority to prohibit either the generation or the use of discrete reduction credits if the executive director determines that the company has violated any of the requirements of the program or has abused the privileges provided by the program. Rule language concerning the start date for the discrete emission reduction program has been removed, since this program is currently ongoing.

New §101.373 outlines the required protocols of generating, calculating, certifying and registering, using, and transferring discrete emission credits. This section requires discrete emission credits to be determined based on established EPA protocols when available, actual monitoring results, or calculated using good engineering practices. There are no changes from the previous requirements in §101.29 regarding the various means for generating discrete emission credits. The section revises the equation for calculating the amount of DERCs generated to use the lower of the baseline emission rate or the most stringent emission rate. This revision will allow for the correct calculation of DERCs if the baseline emission rate was exceeding the emission rate required by local, state, or federal requirements. As previously in §101.29, the section would require DERCs to be rounded down to the nearest ton. The section limits the generation period for DERCs to five years. The section would not allow a source to generate discrete emission credits for any emissions exceeding its allowable emission limit. The section deletes a requirement that previously existed in §101.29, which restricted reductions used for netting from being generated as DERCs. The new section states what requirements and data must be documented to calculate MDERCs.

The language previously located in §101.29 regarding registration and certification of emission credits remains the same and is relocated to §101.373. The section adds language detailing what information, at a minimum, would be required to generate mobile discrete emission credits. The information, which is to be submitted on DEC-1 Form, includes the information necessary for the executive director to review the application in accordance with the new rules and to properly administer the program. It should be noted that, for continuing credits, each application will be reviewed for creditability at the time of submittal in addition to the time of strategy implementation. The new rule language specifically states the commission's practice that discrete emissions credits will be determined and certified to the nearest ton. The section includes new language regarding the review of discrete emission reduction registrations for credibility upon receipt and that applicants being denied registration of discrete emission credits would be notified of such denial in writing. The section states that discrete emission credits will be reviewed and certified based on actual monitoring data, EPA methodology, or other commission approved protocols. In addition, rule language is added which states that discrete emission credits will be deposited in the registry and will be available for use until they are used, withdrawn, or expire. The compliance and burden language is essentially the same as formerly stated in §101.29. The user would be responsible for ensuring that the discrete emission credits are certified and certification, by the executive director, does not relieve the user on any other responsibilities. Previously existing §101.29 language regarding what discrete emissions can or cannot be used for has been reorganized into subparagraphs which state what the discrete emission credits can be used for and a subparagraph which states what they cannot be used for.

The adoption relocates the equations which provide flexibility to the 30-day rolling average emission limits and the new maximum daily emission limit for source caps as defined in Chapter 117 from §101.29 to new §101.373. The commission modified the equation used to calculate the amount of discrete emission credits needed to demonstrate compliance or meet a regulatory requirement to be consistent with the terms adopted for this division, and added language which would be consistent with the procedures and methodologies adopted within this division.

The equations for calculating 30-day rolling average emission limits are relocated from §101.29 to §101.373 unmodified. There are no changes to the existing requirements for additional credits needed as compliance margins or for environmental contributions. As previously stated in §101.29, the calculated discrete emission credits will be rounded up to the nearest ton and the user must retire 10% more than are needed. The amount of discrete emission credits needed for NSR offsets would remain equal to the quantity of tons needed to achieve the maximum allowable emission level set in the user's NSR program. As previously stated in §101.29, discrete emission credits which are not used during the use period would remain surplus and available for use or transfer by the holder. As previously stated in §101.29, a notice of intent to use the DEC-2 Form would be submitted to inform the executive director of the intent to use discrete emission credits. The information required to be submitted on the DEC-2 Form would remain the same as previously stated in §101.29. The section includes a list of the required information to be submitted when a mobile source user intends to use discrete emission credits. The requirement for a user to notify the executive director of the amount of actual discrete emission credit use remains the same as previously stated in §101.29 with the exception of added language requiring the user to submit the information on a DEC-3 Form. The language regarding compliance burden and enforcement for discrete emission credit users is transferred unchanged from §101.29.

New §101.374 is a relocation of requirements from §101.29, with no changes, concerning auditing of the DERC program. The word "section" as found in proposed §101.374(a) was replaced with "division" since the intent was to refer to the entire Division 4 and not §101.374.

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION

The commission has reviewed the adopted rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225. Divisions 1 and 4 create a voluntary mechanism which provides regulatory flexibility for compliance with state and federal emission limitations and do not add mandatory regulatory requirements or required costs. Division 3 affects owners and operators of new and existing stationary sources emitting NO_x subject to §§117.106, 117.206, and 117.475 requirements in the HGA nonattainment area. The commission has determined the adopted rulemaking in Division 3 of Chapter 101 meets the definition of a "major environmental rule" as defined in Texas Government Code, §2001.0225, but adopted rulemaking in Divisions 1 and 4 does not. "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 adopted rules do not meet any of the four applicability criteria for requiring a regulatory analysis of "major environmental rule" as defined in the Texas Government Code. Section 2001.0225 applies only to a major environmental rule the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

As discussed earlier in this preamble, these adoptions are one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000, and planned to be submitted to the EPA by December 31, 2000.

Under the cap and trade portion of these rules, existing sources would be limited to NO_x emission levels under an emissions cap based on historical operating data and source specific emission rates determined by Chapter 117. New stationary sources would be required to identify a source(s) of allowances equal to allowable emissions prior to commencing operation. All sources subject to this division would be required to hold a quantity of allowances in their compliance account by February 1 following the end of a control period, which is equal to or greater than the total emissions from the preceding control period. The cost of allowances in similar programs nationwide has ranged from approximately $500 to $5,000 per allowance (ton), depending on availability and demand. Actual costs in the HGA nonattainment area will be dependent upon market demand and availability. The commission is proposing these sections as part of a strategy to reduce and permanently cap emissions of NO_x to a level which would allow the HGA nonattainment area to attain the NAAQS for ozone. This is based on the analysis provided in the rule proposal preamble which was published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8137), including the discussion in the Public Benefit and Costs section.

These rules do not exceed an express standard set by federal law, since they implement requirements of the FCAA. Provisions of 42 USC, §7410, require 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. These rules were specifically developed as part of an overall control strategy to meet the ozone NAAQS set by the EPA under 42 USC, §7409. While 42 USC, §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 the FCCA, 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 42 USC, §7410. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410 and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to achieve reductions in ozone precursor emissions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. By policy, the EPA requires photochemical grid modeling to demonstrate whether the 42 USC, §7511a(f), NO_x measures would contribute to ozone attainment. The commission has performed photochemical grid modeling which predicts that NO_x emission reductions, such as those required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The 42 USC, §7511a(f), exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under 42 USC, §7511a(f), was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

During the 75th Legislative Session, Senate Bill (SB) 633 amended the Texas Government Code to require agencies to perform a regulatory impact analysis of certain rules. The intent of SB 633 was to require agencies to conduct a RIA of extraordinary rules. 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 previously discussed, 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 proposes and adopts SIP rules. The legislature is presumed to understand this federal scheme. If each rule adopted 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.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967) ; *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035.The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore, in addition to not exceeding an express standard set by federal law, the rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, and 382.017 authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

Comments received during the comment period regarding the draft RIA are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

TAKINGS IMPACT ASSESSMENT

The commission evaluated this rulemaking action and performed an analysis of whether the rules are subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. These sections are adopted as part of a strategy to reduce and permanently cap emissions of NO_x to a level which would allow the HGA nonattainment area to attain the NAAQS for ozone. Promulgation and enforcement of the rules will not burden private real property. The new sections do not affect private property in a manner which restricts or limits an owner's right to the property that would otherwise exist in the absence of a governmental action. Additionally, the credits and allowances created under these rules are not property rights. Consequently, these sections do not meet the definition of a takings under Texas Government Code, §2007.002(5).

Also, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rule revisions 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 significantly advance the health and safety purpose. In addition, §2007.003(b)(4) provides that Chapter 2007 does not apply to the adopted rules since they are reasonably taken to fulfill an obligation mandated by federal law. Specifically, the emission limitations and control requirements within this adoption were developed in order to meet the ozone NAAQS set by the EPA under the FCAA, §7409. States are primarily responsible for ensuring attainment and maintenance of the NAAQS once the EPA has established them. Under the FCAA, §7410 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 the rule adoption is to implement a NO_x strategy which is necessary for the HGA area to meet the air quality standards established under federal law as NAAQS. This action is taken in response to the HGA area exceeding the NAAQS for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient NO_x and ozone levels in HGA. Attainment of the ozone standard will eventually require substantial NO_x reductions. Any NO_x reductions resulting from the current rulemaking are no greater than what the best scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard. Consequently, the exemption which applies to these rules is that of an action reasonably taken to fulfill an obligation mandated by federal law. Therefore, these revisions do not constitute a takings under Texas Government Code, Chapter 2007.

The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

Comments received during the comment period regarding the takings impact assessment (TIA) are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

COASTAL MANAGEMENT PROGRAM CONSISTENCY REVIEW

The commission has determined that this rulemaking action relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 *et seq.*), and the commission's rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with the Texas Coastal Management Program. As required by 30 TAC §281.45(a)(3) and 31 TAC §505.11(b)(2), 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, and has determined that the adopted 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. If adopted, the new sections will reduce and cap emissions of NO_x in the HGA nonattainment area to a level that would allow attainment of the NAAQS for ozone. No new contaminants will be authorized by these rules, and a reduction of NO_x emissions should occur.

Comments received during the comment period regarding the Coastal Management Program Consistency Review are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMIT PROGRAM

The new sections under Divisions 1, 3, and 4, will become part of the state's ozone attainment strategy; therefore, these amendments will be submitted as part of the SIP. As a result, the new sections and any allowances allocated under these sections would become applicable requirements under the federal operating permit program.

HEARINGS AND COMMENTERS

The commission held public hearings on this adoption at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (TWO hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000. The following commenters provided oral testimony and/or submitted written testimony: Avista-Steag,LLC (Avista-Steag), BASF Corporation (BASF), Business Coalition for Clean Air (BCCA), Calpine Central LP (Calpine), Chevron Phillips Chemical Company (Chevron), City Public Service of San Antonio (CPS), City of Spring Valley (Spring Valley), Clean Air Action Corporation (CAAC), Coalition for Gas-Based Environmental Solutions (Coalition), Diamond Koch (Diamond-Koch), Dow Chemical Company (Dow), Dynegy, Inc. (Dynegy), Enron Corporation (Enron), Entergy Services, Inc. (Entergy), Enterprise Products Operating, LP (Enterprise), Environmental Defense (ED), Equistar Chemicals, LP (Equistar), ExxonMobile Corporation (ExxonMobile), FPL Energy (FPL), Fuel Tech, Inc, (Fuel Tech), Gas Processors Association

(GPA), Goodyear Tire and Rubber Company (Goodyear), Houston Galveston Area Council (HGAC), Houston Metropolitan Planning Organization's Transportation Policy Council (The Council), Kinder Morgan, Inc. (Kinder Morgan), League of Women Voters of Texas (LWV-TX), Lyondell Chemical Company (Lyondell), Lyondell-Citgo Refining, LP. (LCR), National Aeronautics and Space Administration (NASA), Pasadena Paper (Pasadena), Peco Energy Company (Peco), Phillips 66 Company (Phillips 66), Printing and Image Association of Texas (PIAT), RMT, Inc. (RMT), Regional Air Quality Consensus Group (RAQCG), Reliant Energy, Inc. (Reliant), Sierra Club Houston Regional Group (Sierra-Houston), Solutia (Solutia), Stolt-Nielsen Transportation Group Ltd. (SNTG), Texas Industrial Project (TIP) via Baker Botts, LLP, TXI Operations, LP. (TXI), TXU Business Services (TXU), Tennessee Gas Pipeline Company (TGP), Texas Chemical Council (TCC), Texas Eastern Transmission Corporation (Texas Eastern), Texas Oil and Gas Association (TxOGA), Texas Pulp and Paper Industry Environmental Council (TPIEC), Trunkline Gas Company (TGC), U.S. Environmental Protection Agency (EPA), Valero Refining Company-Texas (Valero) and twenty three individuals. The companies and organizations expressed general support for the cap and trade concept but opposed many parts of the proposed implementation and suggested changes. These comments are detailed under ANALYSIS OF TESTIMONY. Fifteen individuals opposed the cap and trade concept. Eight individuals expressed general support for the cap and trade concept.

ANALYSIS OF TESTIMONY

Baker Botts commented that it generally supports the ongoing efforts by the commission to develop a SIP that is technologically achievable, economically reasonable, and legally approvable. Baker Botts, BCCA, Dynegy, Equistar, ExxonMobil, Goodyear, Harris County Judge Robert Eckels, Phillips 66, TCC, TPIEC, TxOGA, Valero, and an individual commented that the commission should incorporate into the SIP a greater level of reductions from federally preempted sources and stated that EPA-regulated sources account for about 40% of the NO_x emissions in the HGA. The commenters stated that the EPA issued a number of regulations for some federally preempted sources, such as land-based spark engines, marine, recreational and land-based diesel engines, aircraft and locomotive engines, well after the FCAA deadlines, and that the EPA recently strengthened rules for on-road and non-road vehicles and fuels, such as low sulfur gas and diesel, Tier II motor vehicles, heavy-duty highway vehicle standards, and non- road Tier II/Tier III heavy-duty engine standards. The commenters stated that delays in implementing these rules have prompted the commission to propose technically and economically infeasible emission reductions from sources in HGA that the state has authority to regulate to make up for the missing federal reductions. The commenters stated that these delays have forced the commission to propose expensive regional fuels and significant use restriction regulations. The commenters stated that the commission and the EPA can ensure an equitable distribution of the compliance burdens necessary to meet mandated air quality improvement in HGA only by allowing the SIP to capture anticipated emission reductions from federally preempted sources. Baker Botts noted that the EPA demonstrated a willingness to assume responsibility for a portion of emission reductions by creating a process in Los Angeles called a "public consultative process," that would resolve issues related to emissions from national and international sources, and that the EPA has also provided flexibility in obtaining offsets by allowing states to provide offsets to refiners based on emission reductions that the EPA projected would result from mobile sources using Tier II gasoline. Baker Botts suggested that this same sort of prospective crediting should be used to develop a more rational HGA SIP, and that the EPA should allow the commission to credit in the SIP the prospective emission reductions that will result from implementation of the Tier II gasoline rule and from other federally preempted sources. Finally, Baker Botts cited two cases wherein the District of Columbia Circuit has approved the EPA's flexibility with respect to statutory deadlines under the FCAA when the EPA has failed to meets its own deadlines, and this failure was deemed to upset the balanced federal/state responsibilities under the FCAA. ExxonMobil commented that it supports the commission and the EPA crediting the HGA SIP with an additional 60 tpd of federally preempted emission reductions that will occur over the next ten years. Harris County Judge Robert Eckels commented that the commission should work with the EPA to accelerate the implementation schedule for federally preempted emissions so that at least one-half of the related emission reductions are achieved by 2007, and that as a part of this process, the commission should delineate federal assignments detailing the engine standards and emission reductions necessary to achieve real and sustainable pollution reductions. TPIEC commented that the proposal should incorporate an appropriate level of federally preempted programs to address the proposal's undue reliance on state regulated sources.

The rule has not been revised based on these comments. The commission agrees with the commenters that emission reductions from federally preempted sources would provide benefits for the HGA SIP demonstration, and the inability of the commission to regulate certain source categories has necessitated the use of other ozone control strategies. However, the commission understands that the EPA SIP approval process does not provide a mechanism for credit for emission reductions that occur after the attainment date. The commission understands that the EPA is not currently considering accelerating implementation schedules for existing federal rules. The commission is working with the EPA to determine the availability of SIP credit for many non-traditional control strategy mechanisms, like economic incentive programs and flexibility for preempted source categories. Additionally, the commission is working with the EPA to determine an appropriate federal contribution credit available for the HGA SIP.

BCCA, Entergy, Equistar, ExxonMobil, Goodyear, GPA, Kinder Morgan, Lyondell, PECO, Phillips 66, REI, TPIEC, and TXI, commented on the draft RIA and stated that the proposed rules were not evaluated in accordance with the analysis requirements for a major environmental rule. The commenters stated that Texas Government Code, §2001.0225, requires an RIA for certain major environmental rules. The commenters stated that the commission must consider the benefits and costs of the proposed rules in relationship to state agencies, local governments, the public, the regulated community, and the environment. The commenters stated further that the commission must also incorporate aspects of this analysis into the fiscal note in the proposed rules (e.g., identify the costs and the benefits; describe reasonable alternative methods for achieving the purpose of the rules considered by the agency; provide the reasons for rejecting those alternatives; and identify the data and methodology used in performing the analysis). The commenters stated that under §2001.0225(d) the commission must also find that "compared to the alternative proposals considered and rejected, the rule will result in the best combination of effectiveness in obtaining the desired results and of economic costs not materially greater than the costs of any alternative regulatory method considered."

The commenters stated that the rule proposal preamble's statement that the rules are exempt from the RIA requirement because federal law mandates the rules is a legally flawed effort to avoid an RIA and may render the rules invalid. The commenters stated that federal law does not mandate the control requirements, emission rates, and use restrictions contained in the proposal and asserted that many of the proposed rules exceed specific federal rules and standards applicable to the same sources. The commenters stated that examples of departures from the federal framework include the following: boiler, turbine and other fired equipment emission limits set well below federal new source performance standards (NSPS), RACT, best available control technology (BACT), or lowest achievable emission rate (LAER) limits for the same sources; and compressor engine emission limits set at unprecedented low levels specifically designed to be unachievable and prevent the further use of the affected engines.

TXI stated that the NAAQS does 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. TXI 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." TXI stated that none of the state laws cited in the rule proposal preamble (TCAA, §§382.011, 382.012, and 382.017) is "an 'express requirements of state law' to adopt these NO_x emission rules."

TXI 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-eight that "The 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." (TXI's emphasis added)

TXI stated that the commission must quantify the costs associated with the proposal either for the purpose of determining the reasonableness of the proposed NO_x controls for achieving the commission's desired result or for complying with the specified requirements of §2001.0225. TXI asserted that the commission did not perform a study of the costs associated with the proposed rule for lightweight aggregate kilns. TXI also asserted that the commission did not perform a quantitative analysis of the estimated cost to the Texas lightweight aggregate industry and that without such an analysis, the commission cannot determine the reasonableness of the proposed rule from an economic perspective.

The commenters stated that the rule proposal preamble acknowledges that the rule proposal's components are "major environmental rules," but that the commission asserted that an RIA is "seldom" required and is only required for "extraordinary" rules. The commenters stated that these criteria appear nowhere in the RIA requirements. The commenters stated that the rule proposal preamble states that "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." The commenters stated that this "no greater than is necessary or appropriate" determination is the conclusion that an RIA is designed to evaluate and to offer for public review and comment. The commenters stated that the rule proposal is well beyond any federal mandates for the covered sources and are "extraordinary." The commenters stated that under Texas Government Code, §2001.0225, an RIA must be performed and offered for public comment before the proposal can be adopted.

The rules have not been revised based on these comments. The commission agrees that the cap and trade portion of the rules meets the definition of a major environmental rule; however, the commission disagrees that its interpretation of the exemption for federally mandated standards is legally flawed. While the rules may limit growth of emissions from point sources in the HGA nonattainment area, that alone is not enough to trigger the RIA requirements. Texas Government Code, §2001.0225 only applies to a major environmental rule adopted by a state agency, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

This rulemaking action does not meet any of these four applicability requirements, and is adopted in substantial compliance with the RIA requirements. Texas Government Code, §2001.035. This rule does not exceed an express standard set by federal law because the cap and trade rules are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. Title 42 USC, §7410 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 42 USC, §7410 does not specifically prescribe programs, methods, or reductions to meet the federal 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 FCAA, Chapter 85, Air Pollution Prevention and Control). The FCAA does require some specific measures for SIP purposes, such as an inspection and maintenance program, but those programs are the exception, not the rule, in the federal SIP structure. 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. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Failure to develop control strategies to demonstrate attainment can result in federal sanctions. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by States to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commissions photochemical modeling and other analysis indicates that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to achieve reductions in ozone emissions in the HGA nonattainment areas. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with this rule are a necessary element of the attainment demonstration required by the FCAA.

This conclusion is supported by the legislative history for Texas Government Code, §2001.0225. During the 75th Legislative Session, Senate Bill (SB) 633 amended the Texas Government Code to require agencies to perform a regulatory impact analysis of certain rules. The intent of SB 633 was to require agencies to conduct a RIA of 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. 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. Because of the ongoing need to address nonattainment demonstrations required by federal law, the commission routinely proposes and adopts SIP rules. If each rule proposed for inclusion in the SIP was incorrectly considered as exceeding federal law, every SIP rule would require the full RIA contemplated by SB 633. This result would be inconsistent with the cost estimates and fiscal notes prepared by the commission and by the Legislative Budget Board (LLB). 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 meet the requirements under §2001.0225(a). 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. In other words, the proposed rule is intended to meet federal and state law, and does not go above and beyond what is required to meet federal or state statutes.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Administrative Procedure Act (APA) by the Legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore, in addition to not exceeding an express standard set by federal law, this rulemaking does not exceed state requirements, and is not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, and 382.017 authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

BCCA, Entergy, ExxonMobil, Equistar, Goodyear, Lyondell, Phillips 66, REI, and TPIEC stated that the proposed rules did not include an adequate TIA as required under Texas Government Code, §2007, with Goodyear stating that the proposal amounts to a taking of its engines (including a recently retrofitted engine) "not supported by adequate scientific support, public participation, or legal process." The commenters stated that the TIA provision mandates that covered agencies "take a 'hard look' at the private real property implications of the actions they undertake...," according to the Office of the Attorney General, *Private Real Property Rights Preservation Act Guidelines*, (January 12, 1996 issue of the *Texas Register* (21 TexReg 387)). The commenters stated that under §2007.043, a TIA must describe the specific purpose of the proposed action, determine whether engaging in the proposed governmental action will constitute a taking, and describe reasonable alternative actions that could accomplish the specified purpose. The commenters stated that the agency must also explain whether these alternative actions also would constitute takings.

The commenters stated that agencies must also comply with guidelines developed by the Texas Attorney General when developing the TIA and that according to these guidelines, agencies must carefully review governmental actions that have a significant impact on the owner's economic interest. The commenters stated that these guidelines include the statement: "Although a reduction in property value alone may not be a 'taking,' a severe reduction in property value often indicates a reduction or elimination of reasonably profitable uses." (January 12, 1996 issue of the *Texas Register* (21 TexReg 392)). The commenters stated that examples of aspects of the rule proposal that could significantly impact private real property in a manner that constitutes a taking include gas-fired compressor engines and other point source NO_x controls. The commenters stated that the rule proposal preamble acknowledged that retrofitting compressor engines to the level specified in the proposal is infeasible (25 TexReg 8137 and 8291), and stated that the existing equipment, representing a significant capital improvement at a number of industrial sites, would be rendered unusable. The commenters stated that the 90% point source reduction requirement is economically and technologically infeasible for a number of existing sites, and that this requirement could cause a number of facilities to shut down their operations, dramatically impacting the value of their real property.

The commenters stated that the proposed rule preamble acknowledged that some of the rules may "burden" private real property but claimed an exemption from performing a TIA based on the assertion that the proposal does not impose a greater burden than necessary to advance a health and safety purpose and that the proposal "reasonably" fulfills a federal mandate. (25 TexReg 8175, 8194, 8201, 8208, 8220, 8228, 8237, 8245, 8294, and 8295). The commenters stated that the commission provided the public no basis to infer that a cost/benefit analysis or a reasonableness determination was, in fact, performed as necessary to support the TIA exemption claim because the preamble contains only the bare assertions. The commenters asserted that the proposed rules will impose a greater burden than is necessary, and are not reasonably taken to fulfill a federal mandate. The commenters commented that according to the Attorney General's Guidelines, a full TIA was required to be completed with the proposal, and that failure to perform a TIA could invalidate the rules.

The rules have not been revised based on these comments. The primary reason the commission determined that these rules did not constitute a takings under Texas Government Code, Chapter 2007 is that it will not burden private real property. The allowances created under these rules, like other authorizations to emit, are not property rights and therefore cannot be the basis for a takings claim. Generally, these rules themselves should not impose any requirements on point sources, but only requirements of recordkeeping and reporting. In fact, these rules provide flexibility for meeting the requirements of the revisions to Chapter 117 regarding NO_x reductions from point sources in the HGA nonattainment area which are adopted concurrent with this rulemaking. To the extent that the commenters are concerned about takings implications of the requirements of the Chapter 117 rule revisions, they may review the response to this comment in the preamble for those rule revisions which are published elsewhere in this version of the *Texas Register*.

In its analysis, the commission also found that the rules are exempt from Chapter 2007 pursuant to §2007.003(b)(4) because they are reasonably taken to fulfill an obligation mandated by federal law. The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking therefore meets the requirements of §2007.003(b)(4). Although the rule revisions 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 significantly advance the health and safety purpose and they therefore meet the requirements of §2007.003(b)(13) as well. For these reasons the rules do not constitute a takings under Chapter 2007 and does not require additional analysis.

BCCA, Entergy, ExxonMobil, Equistar, Goodyear, Lyondell, Phillips 66, REI, and TPIEC stated that the proposed rules did not include an adequate small business and micro-business assessment as required under Texas Government Code, §2006.002. The commenters stated that an analysis of the costs of compliance for small and micro-businesses must also compare the costs of compliance for these businesses with the costs for the largest businesses affected by the rules. The commenters stated that the comparison must use at least one of the following standards: cost for each employee, cost for each hour of labor, or cost for each $100 of sales. The commenters asserted that the rule proposal failed to include the mandated cost comparison standards. The commenters stated that this is the case even in those instances where the commission acknowledged a significant impact. The commenters stated that the commission either restated the costs of compliance it identified in the analysis of public benefits and costs, or concluded that it cannot determine the cost to small businesses. The commenters stated that the rule proposal preamble stated that "the estimated capital and annualized cost of installing and operating control technology used for the various types of equipment in fiscal note would appear to be a reasonable cost estimate for small and micro-businesses." (25 TexReg 8293).

The commenters asserted that the rule proposal's assessments fall short of what Texas law requires and that it is not sufficient for the agency merely to state that the costs for small and large businesses will be the same. The commenters stated that the rationale behind requiring a comparison using an established standard (e.g., cost for each employee, cost for each hour of labor, or cost for each $100 of sales) is to determine whether there is a disparate impact on small businesses. The commenters stated that according to *Unified Loans v. Pettijohn*, 955 S.W.2d at 652 (Court of Appeals -- Austin, 1997), the statute's purpose is to obtain "an objective assessment of the agency's proposed action by forcing it to consider seriously. . . the effect of the rule on small businesses, including an analysis of their costs of {compliance} and a comparison of their costs with the cost of compliance for the largest businesses affected. ..." The commenters stated further that the commission cannot merely conclude that the costs to small businesses "cannot be determined," and is obliged to include in the notice "some basis" for its conclusion so that interested parties can "confront that basis in a meaningful way in their comments." (*Unified Loans v. Pettijohn*, 955 S.W.2d at 653.)

The commenters stated that in the rule proposal preamble, the commission did not publish the information mandated by Texas law and that as a result, it is impossible for the public to comment on whether the agency adequately considered the effect of the rule on small businesses, thus rendering the notice of the plan inadequate. The commenters stated that Texas Government Code, §2006.002, requires the commission to provide a comparison of the proposed rule's impact on small and large businesses, using the specified standards, for public review and comment before adoption.

The rules have not been revised based on these comments. The agency has estimated, to the extent possible, the costs to small businesses and has determined that there is no cost of the voluntary portion of these rules, Divisions 1 and 4, and that the cost of compliance with the cap and trade program will be minimal. The only costs created by this rulemaking are the costs of recordkeeping and reporting. These costs are mitigated for smaller facilities by excluding those facilities which are ten tons or less. In fact, these rules provide flexibility for meeting the requirements of the revisions to Chapter 117 regarding NO_x reductions from point sources in the HGA nonattainment area which are adopted concurrent with this rulemaking. To the extent that the commenters are concerned about the costs of the Chapter 117 rule revisions to small businesses, they may review the response to this comment in the preamble for those rule revisions which are published elsewhere in this version of the *Texas Register*.

The comments which state there are critical gaps did not identify what these gaps are or how that results in inadequate notice.

The commission is unaware of any requests for additional information to which it was not completely responsive.

BCCA, Entergy, ExxonMobil, Equistar, Goodyear, Lyondell, Peco, Phillips 66, REI, and TPIEC stated that the proposed rules did not include the local employment impact statement required under Texas Government Code, §2001.022. The commenters stated that Texas Government Code, §2001.022, requires the commission to determine whether the rule proposal has the potential to affect a local economy before proposing the rules for adoption. The commenters stated that if answered affirmatively, the commission must request that the Texas Employment Commission to prepare a local employment impact statement describing in detail the probable effect of the rules on employment in each geographic area affected by the rules for each year of the first five years that the rules will be in effect. The commenters further asserted that the commission failed to make the required initial determination and ignored the potential for the proposal to adversely affect the local economy. The commenters stated that a local employment impact statement should have been requested and prepared in advance of the proposal.

The rules have not been revised based on these comments. The commission agrees with the commenters that the proposed rulemaking may affect a local economy, however, does not agree that it is the responsibility of the commission to provide the local employment impact analysis. The APA requires state agencies to determine whether a rule may affect a local economy before proposing a rule for adoption. If the agency determines that a proposed rule may affect a local economy, the agency must send a copy of the proposed rule and other information to the Texas Workforce Commission before the agency files notice of the proposed rule with the secretary of state. The APA requires the Texas Workforce Commission to prepare a local employment impact statement for proposed rules, if a state agency requests the statement. The commission determined that the proposed rulemaking might affect a local economy, and sent the proposed rules and other requested information to the Texas Workforce Commission. The commission received a letter from the Texas Workforce Commission, indicating that the Texas Workforce Commission did not have the ability to determine the potential local employment impacts from the proposed rules.

BCCA, Entergy, ExxonMobil, Equistar, Goodyear, Lyondell, Peco, Phillips 66, REI, and TPIEC stated that the proposed rules did not include adequate notice as required under Texas Government Code, §2002.024. The commenters stated that Texas Government Code, §2001.024, requires adequate notice of a proposed rule, including information about its public benefits and costs. The commenters stated that adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule, and that courts have considered notice "adequate" only if: interested persons can confront the agency's factual suppositions and policy preconceptions; and the agency provides interested parties the opportunity to challenge the underlying factual data relied upon by the agency. The commenters asserted that in proposing the rules, the commission failed to provide interested parties with sufficient information to constitute adequate notice.

The commenters stated that the rule proposal preamble appears short of adequate notice because the cost estimates were "dramatically underestimated." The commenters stated that the commission published insufficient information and analysis regarding costs and impacts.

The commenters also noted that the rule proposal preamble stated that "there may be individual sources for which the equipment actual control costs are higher than the ones identified in this cost note," and asserted that through this statement the commission "acknowledged that its estimates may have been low."

The commenters stated that it has identified a number of critical gaps in the underlying factual data, methodology, and analysis in support of the proposed rules. The commenters asserted that the proposal included insufficient information and analysis regarding costs and impacts. The commenters asserted that the commission has not adequately responded to requests for additional information from stakeholders. The commenters stated that the following requests for information were outstanding: information regarding the modeling of emissions; information regarding the corrected emissions inventory database; and information supporting the estimated costs of control. The commenters stated that this information is necessary in order to comment effectively on the proposed rules and that data gaps in the proposal hindered effective comment.

The commission disagrees with the commenters and has made no change in response to these comments. Texas Government Code, §2001.024 requires of the notice of a proposed rule include certain information. Texas Government Code, §2001.024(5) requires that the notice state the public benefits expected as a result of the adoption of the proposed rules and the probable economic cost to persons required to comply with the rule. Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn*, 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of the proposed rules. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The commission has determined that there is no cost of the voluntary portion of these rules, Divisions 1 and 4, and that the cost of compliance with the cap and trade program will be minimal. The only costs created by this rulemaking are the costs of recordkeeping and reporting. In fact, these rules provide flexibility for meeting the requirements of the revisions to Chapter 117 regarding NO_x reductions from point sources in the HGA nonattainment area which are adopted concurrent with this rulemaking. To the extent that the commenters are concerned about the costs of the Chapter 117 rule revisions, they may review the response to this comment in the preamble for those rule revisions which are published elsewhere in this version of the *Texas Register*.

The comments which state there are critical gaps did not identify what those gaps are or how that results in inadequate notice. The commission is unaware of any requests for additional information to which it was not completely responsive.

Sierra-Houston and one individual commented that the proposed rules should be adopted statewide. Others generally comment that the commission should be doing more than what is proposed in this rulemaking.

The rules have not been revised based on these comments. The commission appreciates the commenters' support for statewide applicability of the rules. The commission notes, however, that it is not obligated to adopt all rules statewide in order to satisfy its commitments under the SIP, nor is the commission required to do so under the Federal Clean Air Act. Three of the proposed measures contain emission reduction strategies that have been proposed for statewide applicability: California Large-Spark Ignition Engines; Emissions Banking and Trading Program (that portion of the proposed rule which relates to the trading of emission reduction credits and discrete emission reduction credits); and Cleaner Diesel Fuel (that portion of the proposed rule which relates to on- highway fuel).

In evaluating whether to implement all of the rules statewide, the commission took into account many concerns, including, but not limited to, the need for the marketplace to be able to respond to regulation, the possible impacts on transport and distribution systems, the possibility of increased costs and financial burdens on regulated entities, and regional needs and issues associated with statewide mandates. The commission analyzed where emission reduction measures are most needed and where emission reduction measures will be most effective in order to demonstrate attainment.

An individual stated that the SIP should require reductions in the range of 90% of VOC and NO_x for all of East Texas.

The rules have not been revised in response to this comment. The commission has not determined that reductions of this magnitude are required in East Texas in order for the HGA area to attain the ozone standard. The cap and trade program will only affect the HGA eight-county nonattainment area and will only be used to limit NO_x emissions. The commission may investigate the validity of expanding the cap and trade program to other counties, including East Texas. The commission may also consider expanding the program to cap other criteria pollutants. If it is determined that additional counties and/or pollutants should be controlled under the cap and trade program, further rule making would be required.

One individual commented that these rules are being set up to embarrass Texas and the Governor, and that he hopes that State Legislators and Congress would investigate these plans.

The rules have not been revised based on this comment. The commission's intent is not to embarrass Texas and the Governor, but instead to comply with the timelines provided in 1990 FCAA amendments and subsequent EPA guidance for submitting rules to demonstrate ozone attainment in HGA. Accordingly, Texas has committed to adopting the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000.

Sierra-Houston resubmitted comment letters dated August 2, 1999, January 31, 2000, and February 24, 2000 concerning already-completed rulemakings and SIP revisions which Sierra-Houston had initially submitted during the comment period for these previous rulemakings and SIP revisions.

The rules have not been revised based on this comment. These comments were addressed in the ANALYSIS OF TESTIMONY section of the preambles to the earlier rulemakings and SIP revisions which were published in previous issues of the *Texas Register*.

The EPA commented that authorizations under Chapters 106 and 116 should be approved as SIP revisions before limits under these Chapters can be used in the setting of allowances.

The rules have not been revised based on this comment. The commission does not believe that it is necessary to submit authorizations under Chapters 106 and 116 as SIP revisions. On August 13, 1982, (47 Federal Register 35183), the EPA published its approval of several revisions to 30 TAC Chapter 116 that were submitted to the EPA for SIP approval on May 9, 1975. Part of that May 9, 1975 submittal included §116.6, Exemptions. Although §116.6 has since been revised, the version that existed at the time of the August 13, 1982 SIP approval has not been withdrawn from the SIP. Thus, the basic regulatory authority for exemptions, now permits by rule, is in the SIP. In a letter dated June 4, 1990 from Merrit Nicewander, Chief, New Source Review Section, EPA Region VI, to Lawrence Pewitt, Director of the Texas Air Control Board (TACB) Permits Division, the EPA stated that where the TACB issues standard exemptions pursuant to state regulations that were developed in accordance with the Texas SIP, the standard exemptions themselves are federally enforceable. Additionally, since Chapter 116 itself has been submitted and approved as part of the SIP, authorizations made under 116 are enforceable by the EPA.

Thus, since permits and permits by rule are federally enforceable, there is no need to submit each authorization individually as a SIP revision.

Under the definition of "source" the executive director has the authority to determine whether multiple processes exhausting from single point is treated as a single or multiple source. The EPA stated the commission should address how this definition is consistent with new source review and prevention of significant deterioration requirements.

The commission has made no changes in response to this comment. The definition of "Source" in both §101.300 and §101.370 are consistent with §101.1 which states that a source is a "point of origin of air contaminants, whether privately or publicly owed or operated." The definition in these sections goes on further to state "Upon request of a source owner, the executive director shall determine whether multiple processes emitting air contaminants from a single point of emission will be treated as a single source or as multiple sources." The definition is accurate for its intended purpose for defining a source of emissions when determining the generation and use of emission credits under Subchapter H, Divisions 1 and 4. For NSR and PSD purposes, if a permit were to rely on an emission reduction or emission credit then that reduction or credit would be applied to the applicable "source" as described under the NSR or PSD rules and regulations. Since the definition in these sections applies only to these sections, it does not have to be identical to the definitions in NSR and PSD programs.

The EPA commented that the rule should address environmental justice issues for VOC trades such as specific notice of trades to nearby communities. Sierra-Houston commented that cap and trade programs are not set up to account for environmental justice issues.

The rules have not been revised based on these comments. Sections 101.302(e) and 101.372(f) of the adopted rules provide for the executive director to halt trading for a certain area if problems result from trading in a localized area of concern. Under §101.373(f)(6)(A), increases in emissions by use of credits are allowed only on a temporary basis, not perpetually, and are limited to 25 tons for NO_x and five tons for VOC in any 12-month period. Additionally, the only time credits may be used to increase emissions, the conditions of 30 TAC §106.261(3) or (4) or §106.262(3) must be met without a specific impacts review, pursuant to §101.373(f)(7). All other uses would allow sources only to remain at the current emission rates or lower. Therefore, the commission believes that notice for each trade is unnecessary and furthermore would significantly hinder the trading procedures and would discourage use of the trading program.

The EPA commented that it is concerned about creating replicable procedures for the substitution of VOC for NO_x reductions and stated that if the commission's final rules contained such a provision the determination of VOC substitutions would need the EPA approval.

The commission agrees that interpollutant trading should be approved by both the executive director and the EPA. The rules have been changed accordingly in §§101.302(a), 101.356(f), and 101.372(a).

The EPA commented that in the absence of an outlined procedure for demonstrating an improvement in air quality in the "county of use" of a credit, the EPA approval would be required for each trade.

The commission agrees that trading between different nonattainment areas or between attainment and nonattainment areas should be approved by both the executive director and the EPA. The rules have been changed accordingly in §101.302(e) and §101.372(e)(5).

The EPA requested confirmation that the provision in §101.303(a) requiring the EPA approval for deviation from the EPA protocol would limit the clause "or other model as applicable" in the definition of mobile baseline activity.

No change has been made to the rules in response to this comment. The commission confirms that §101.303(a) requires the EPA approval of the use of any mobile model in determining mobile baseline activity. The clause "or other model as applicable" was meant to incorporate the possibility of models which may be created and approved in the future without having to identify them at the present.

The EPA commented that §101.303(e)(3)(I) references regulatory requirements and should also reference statutory requirements.

The rules were revised to incorporate this comment.

The EPA commented that there appears to be a typographical error in §301.303(e)(4)(I) and should read...... that is not prohibited.

The rules were revised to incorporate this comment.

The EPA commented that, if an agreed order is used to make a reduction enforceable, the agreed order should be submitted to the EPA and approved as a SIP revision before the credits are valid for trading.

The rules have not been revised based on this comment. The commission believes that agreed orders which are entered by the commission are enforceable by the EPA through the Texas Clean Air Act which is part of the SIP and through the specific provision for making reductions enforceable through agreed order in this rule and therefore do not need to be submitted individually as SIP revisions.

An individual commented the rules go far beyond what is necessary to protect the environment. Another individual said the banking rules are illegal.

The rules were not revised in response to these comments. The cap and trade portion of the banking rules are a method of compliance with NO_x emission limits that have been demonstrated as necessary to bring the HGA area into attainment with the ozone standard. The commission acknowledges that the limits on growth are strict but disagrees that they go beyond what is required to attain the federal ozone standard. The commission believes the banking and trading rules are consistent with its statutory authority to develop a plan for control of the state's air and its authority to issue permits. Banking and other economic incentive programs are also authorized for use in the SIP by the FCAA, §110(a)(2).

An individual commented that leak reduction at refineries would remove the need for strict rules on the public.

The rules were not revised in response to this comment. The commission requires leak detection as a condition of issuing permits for refineries. Generally leaks at refineries cause the release of volatile organic compounds. The principal focus of these adopted rules is a reduction in NO_x, which is generally emitted due to combustion. The commission believes that actions are required to reduce NO_x from both stationary and mobile sources in order to achieve attainment with federal air quality standards.

An individual stated that trading makes emission limits more difficult to enforce and allows emissions to be hidden.

The rules were not revised in response to this comment. The commission disagrees with this comment. The commission will have a system of tracking and accounting for allowances at individual sources and therefore will know what a sources authorized emission limits are at any time similar to the enforcement methodology of permit allowables. The cap and trade system will not introduce any new difficulties in enforcing those limits.

An individual stated that the trading program should be supported by continuous emission monitoring. Periodic monitoring should not be allowed.

The rules were not revised in response to this comment. The commission believes that it is unrealistic to require all facilities involved with emissions trading to have continuous monitors installed. The cost and need for this requirement is undocumented. If continuous monitoring data is available, it will be used to calculate actual emission reductions. If continuous monitoring is not available, the commission will utilize the best replicable data available, including periodic monitoring, stack sampling, and mass balance calculations. The monitoring requirements for each category of facility is generally set by the rules which apply specifically to those facilities, not by the banking rules. In this way the commission has been able to consider whether the cost of continuous monitoring is outweighed by the benefits for each category of facility.

Two individuals suggested a moratorium on permits.

The rules were not revised in response to this comment. The cap and trade program is designed to cap emissions of NO_x at a level determined to result in attainment of the ozone air quality standard. Because emissions will be capped, no significant increase in overall emissions can occur from permitting activity thus a moratorium on permits is unnecessary.

BCCA, LCR, and Chevron commented that the commission should establish emission trading programs for federally preempted mobile and non-road sources. Such a program should allow for the trading among source categories. HGAC, RAQCG, and The Council commented that certain mobile source emission control programs such as Diesel Emulsion, Accelerated Purchase of Tier II/III Diesel, and NO_x Control Systems be transferred to a voluntary mobile emission reduction program in order to generate NO_x credits for trading. TPIEC commented that the proposal should incorporate an appropriate level of federally preempted programs to address the proposal's undue reliance on state regulated sources.

The rules were not revised based on these comments. The rules will allow any source, including stationary, mobile on-road, and mobile off-road, to bank reductions that are beyond local, state, and federal rules and regulations, provided that the requirements of Chapter 101, Subchapter H, Divisions 1 and 4 are met. To the extent that the control strategies mentioned by the commenters are not already required of the source, they could potentially be creditable.

HGAC commented that the commission should better define what emission reductions are available outside the proposed controls so generators have a greater certainty that they can enter into legitimate trades.

No changes have been made in response to this comment. The rules allow for any reduction that goes beyond any mandatory state or federal requirement to be banked as a credit so long as the reduction meets the requirements of 30 TAC Chapter 101, Subchapter H. Each individual source will have to review its own processes to determine the potential for reduction which can be banked.

LWV-TX commented that any emissions banking and trading program should result in reductions within the same airshed.

No changes have been made in response to this comment. The banking and trading program is designed to reduce NO_x within, and is currently limited to, the eight-county HGA area. The program does not allow for the trading of allowances (emissions) into the area from outside the designated eight counties. Additionally, the ERC and DERC trading programs allow only credits created within a nonattainment area to be used within that same nonattainment area until such time as a demonstration can be made that there is an equivalent air quality benefit to trading between these areas.

Sierra-Houston opposed trading of credits between nonattainment areas and the trading of credits generated in the county, state, or nation. They preferred the actual reduction of emissions.

No changes have been made in response to this comment. The commission only supports trading of credits between counties, states, or nations if it does not adversely affect air quality for any given area. Such a demonstration would require approval of the executive director and the EPA. Trading provides an incentive to reduce emissions since reductions result in an allowance saving that has market value.

Sierra-Houston opposed the trading of one contaminant for another and allowing the executive director discretion in determining the amount of allowances allocated to a source. They stated these provisions of the rules would not result in real reductions.

The commission has not changed the rules in response to this comment. The commission disagrees that trading will not result in real reductions. To the extent that it enables the commission to achieve more overall reduction through other rules, the trading program provides a benefit to air quality. Additionally, trading of ERCs and DERCs in many cases requires the retirement of 10% of the credits used to benefit air quality.

The commission will allow the trading of one contaminant for another if it is demonstrated that an equal environmental benefit is accomplished. For example, if it is sufficiently demonstrated that a reduction of ten tons of VOC would reduce ozone formation in the same way as a reduction of one ton of NO_x, the rule would allow for interpollutant trading at a ratio of ten to one. This demonstration can only occur if a real reduction is made and must be approved by the executive director and the ED. Given the continuing development of the science of ozone and the fact that both VOC and NO_x are precursors to the formation of ozone, it is possible that this flexibility will provide a mechanism to better reduce ozone in nonattainment areas.

Regarding the executive director's discretion to deviate from the standard allocation for allowances, the executive director plans to detail the factors which may be considered for deviation from allocation methodology in a guidance document. The executive director plans to limit deviations to extraordinary circumstances, for example a catastrophe which required a facility to shut down during the historic period upon which allocations would normally be based. The intent of this provision is to prevent significantly low allocations due to the fact that the historic period is not representative a plant's emissions.

SNTG commented that creditable reductions from mobile sources be calculated between the low emitting technology used and the lower of the conventional emission rate and the most stringent allowable emission rate.

There has been no change to the rules in response to this comment. The commission believes that the rules as adopted already accomplish the goal of the commenter. The definition of "surplus" allows only reductions beyond existing requirements to be creditable. So in the event that there is an allowable emission rate which is more stringent than the conventional emission rate, that allowable emission rate would determine how much of the reduction is surplus and therefore creditable.

SNTG commented that emission credits should be generated by comparing an emission reduction strategy to emissions that would otherwise occur without the strategy. This would eliminate the need for a baseline and allow reductions to be accomplished earlier.

The commission has made no changes in response to this comment. The SIP requires that the generation of allowances and credits be accomplished through comparison to a baseline of emissions. Surplus credits can only be generated when an emission control strategy results in reductions not required by any rule, regulation, or order.

TIP, Texas Eastern, TxOGA, Valero, and REI commented that the term baseline emissions should be defined as a source's actual emissions averaged over any consecutive 24-month period between the beginning of the SIP year and the emission reduction strategy period. Fixing the emission baseline to the SIP year is arbitrary and capricious. Where 24 months of data is not available, the executive director may consider any consecutive 12-month period. The definition of baseline activity should be similarly constructed based on operating hours, production rates, types of material processed or combusted. They also commented that the adopted rule should contain a definition of SIP Year as the year of emission inventory data on which applicable SIP provisions are based.

The rule has not been revised based on these comments. The trading programs were developed to provide flexibility to facilities that choose to purchase emission credits in lieu of making actual reductions that would otherwise be needed as part of an attainment strategy. By allowing facilities to use higher baseline emissions, the total number of credits generated from an emission reduction would exceed the facility's emissions as listed in the baseline year which was relied upon for planning purposes of the SIP strategy. Under the commenters' recommendation, double counting of emission reductions in the SIP would be possible. The commission must link the baseline to the SIP year in order to have a stable point from which to plan and therefore the requirement is not arbitrary and capricious.

TIP, TxOGA, Valero, and REI commented that the requirement for an emission reduction to have occurred after the most recent year of emission inventory used for SIP determination in order to be creditable lacks reasoned justification. The timing of reductions should not be limited in this manner.

No change was made in response to this comment. The commission believes that any reduction that occurs prior to a year in which the emissions inventory was relied upon for a SIP demonstration should not be creditable because that reduction, unless already in the bank, will have been relied upon as part of the emission inventory. It would be considered "double counting" if the same reduction were relied upon for SIP purposes and also banked as a credit which could be relied upon to add emissions back to the atmosphere.

HGAC commented that the commission should reconsider allowing trades of VOC and particulate matter (PM) across source types as these contaminant categories contain several toxic elements.

No change was made in response to this comment. There are restrictions on use of VOC discrete credits in §101.373(f)(7) to protect against the potential impact of different types of VOC and PM. Facilities trading PM or VOCs may be subject to a health effects review for any increase in emissions. Any review would be conducted independently of the trade and can result in a restriction on the use of credits regardless of the amount of credits transferred during the trade. Owners of facilities trading PM or VOCs should be aware that this restriction may be applied upon use thus reducing the value of their trade.

TIP, TxOGA, Valero, and REI commented that the Protocols section of the proposal is confusing and that the subjects of the section, credit generation, calculation, registration, and certification should be moved to their own sections. SNTG commented that the rule should be subdivided into divisions for ERCs, MERCs, DERCs, and MDERCs for clarity in terminology.

The rules were not revised in response to these comments. This adoption is the first step of consolidation and reorganization of emission banking and trading rules into one subchapter. The commission agrees that there is a need for further refinement and reorganization and intends to address these issues in future rulemaking.

TIP, REI, TxOGA, Valero, and PIAT commented that the usable life of ERCs should remain at 120 months and the proposal lacks reasoned justification for the reduction in usable life to 60 months.

No changes have been made in response to this comment. The commission has chosen to limit the life of ERCs registered after the effective date of this rulemaking to 60 months from the date the reduction occurred. This change is made to reduce the effect of older reductions on future SIP strategies. The commission has received comments in the past regarding the use of credits for new projects which were five to ten years old. Based on this public concern and the concept that credits generated ten years ago are too remote to allow resurrection of the emissions, the commission has reduced the life of unused ERCs to five years. ERCs registered prior to the effective date of this rulemaking will continue in effect for 120 months.

TIP, TxOGA, Valero, and REI commented that there is no reasoned justification for the requirement to register reductions within 180 days of generation. Such registration should be annual. They further commented that the rule should be clear that failure to register only prevents a source from taking credit for its reduction and is not a matter for enforcement.

The commission has not revised the rule in response to these comments. The commission believes that it is crucial for SIP planning purposes to know which reductions will be banked and thus relied upon in the future for emission growth and which reduction can be relied upon as a permanent reduction. By requiring a project to be registered within 180 days of the reduction, the commission will be able to accurately make that decision. It is possible for air quality strategies to be developed from concept to adopted rule in a six-month period therefore the commission believes the 180 days is needed to provide adequate information on the potential emission reduction credits which could effect the decision making for that strategy. Since participation in the banking program is voluntary, the commission agrees that it should not be an enforcement issue if the 180-day deadline is missed; it simply means the generator has lost the opportunity to bank that reduction as a credit.

One individual stated that there should be no pooled reductions. PIAT requested the option to combine credits into larger blocks for sale to larger companies.

No changes have been made in response to these comments. Credits may be sold individually or in blocks, however, ERCs may not be grouped together and treated as a unit unless the reductions occurred on the same day since ERCs expire based on the generation date.

TIP, TxOGA, Valero, and REI commented that the proposal requires the EPA approval of deviations from emission credit protocols. There is no reasoned justification for this requirement given the commission's responsibility for administering the program.

No change was made in response to this comment. The EPA has established or approved state protocols for emissions trading programs, and, under their guidance document, deviations from those protocols must be EPA approved. Since this banking program is part of the state SIP the commission believes that it is prudent to require the EPA approval to ensure that the program will remain viable under the SIP.

Spring Valley commented that the commission should establish an offset ratio for mobile source emission reduction credits because the generation of mobile emission credits is cheaper than credit generation at stationary sources. RAQCG commented that the commission should consider making the mobile source credit program a separate economic incentive program.

The rules were not revised in response to these comments. The commission believes that establishing an offset ratio for mobile credits would reduce the incentive to develop mobile source control programs and technology and chooses not to implement an offset ratio. If the commenter is correct that mobile emission credits are cheaper to generate the commission expects the market to generate enough incentive to bring about those reductions to be used by point sources. The commission desires to provide maximum flexibility within the cap and trade program and promote mobile source control programs. Therefore the commission will allow unlimited use of MDERCs by sources under the cap and trade program.

TIP, TxOGA, Valero, and REI commented that the proposal prohibits ERC generation from emission reductions resulting from transferring emissions to another piece of equipment. As drafted, the proposal is ambiguous and may interfere with the use of reductions in netting or offsets. They recommend that the definition of "real reduction" be modified so that a transfer of emissions to another unit would be considered a real reduction if it is used in offsetting under §116.150, New Major Source or Major Modification in Ozone Nonattainment Area.

No changes have been made in response to these comments. The rules as proposed allow internal reductions to appear within a netting window but do not allow transferred reductions to be creditable as banked emission reductions. Further clarification will be available through technical guidance after adoption of the rules.

TIP, TxOGA, Valero, and REI commented that the rule should make clear that reductions resulting from the application of state reviewed best available control technology are surplus.

No changes have been made in response to this comment. The commission understands the commenters' concern and the commission will continue to review this issue to determine if best available control technology is relied upon for the SIP and should not be creditable. If a rule change is determined to be necessary it will be proposed in the future.

TIP, TxOGA, Valero, and REI commented that the enforce ability of ERCs following registration using the OPCRE-1 Form should not be limited to grandfathered sources or those sources that use a permit by rule.

No changes have been made in response to this comment. The commission believes that the enforceable mechanism for a permitted facility should be a modification to that facility's permit. The OPCRE-1 Form is strictly used as an alternative to obtaining an agreed board order for grandfathered sources. Sources authorized under permits by rule have always been restricted to using the PI-8 Form.

The EPA commented that the equation in §101.303(f)(8) does not contain variables for a nonattainment area offset ratio or the 10% environmental benefit. The equation should match the rule text.

No change has been made to the rules in response to this comment. The equation in §101.303(f)(8)(C) applies to the limited circumstances where credits are used to exceed a source cap under Chapter 117. In those instances the nonattainment area offset ratio and the 10% environmental benefit do not apply. The text in §101.303(f)(8)(A), (B), and (D) apply to other types of credit uses and specifies what the offset ratio and environmental benefit should be.

Peco commented that the equation in §101.303(f)(8)(C) divides credit into 365-daily increments. This eliminates most credit for units that operate a few weeks or days per year. They also commented that electric generating facilities constructed after January 1, 1999 should be able to use authorized daily heat input as specified by §117.210(c)(1) to determine activity.

The equation that Peco refers to is not applicable to Peco's proposed new facility located in HGA. The equation was developed for use in emission reduction credit trading for sources operating under the source cap, §117.223. The source cap of §117.223 is a voluntary compliance mechanism for industrial, commercial and institutional (ICI) facilities complying with NO_x RACT in BPA, DFW, or HGA, or the attainment demonstration emission specifications for ICI facilities in DFW or BPA. The system caps in §117.108 and §117.210 are compliance mechanisms for EGFs complying with the emission specifications for the attainment demonstration in BPA, DFW and HGA. Participation in these caps for EGFs are voluntary in BPA and DFW, and mandatory in HGA. The commission did not propose a procedure for system cap emission trading for EGFs in HGA in the August, 2000 proposal to these adopted rules. However, a system cap emission trading rule for EGFs in DFW was proposed in the December 1, 2000 issue of the *Texas Register* (25 TexReg 11886). Final action will be taken on this rule proposal by May 31, 2001. In a future rulemaking, the commission may develop system cap trading rules for EGFs in HGA.

Cap and Trade Comments

TXI commented that the program lacked flexibility.

The commission has made no changes in response to this comment. The commission believes that it has provided considerable flexibility within the framework of a stringent cap on NO_x emissions. This flexibility is accomplished through the unrestricted trading of allowances and the ability to use DERCs and MDERCs within the cap. This is an alternative to enforcing emission standards on a facility-by-facility basis which provides the facility operators significant flexibility.

TxOGA and Valero requested the adopted rule contain a statement that allowances and trades are not applicable requirements under Federal Clean Air Act Title V (Title V) requirements.

The commission has made no changes in response to this comment. The cap and trade program is submitted as a revision to the SIP and, as such, the restrictions under this program are applicable requirements under Title V.

TIP, TxOGA, Valero, Peco, REI and BCCA objected to the daily and monthly NO_x limits for utility sources in addition to the annual cap. These limits render the cap and trade flexibility meaningless.

The commission disagrees with this comment and has made no changes to the rules. The 30-day average system cap emission limit functions as a flexible but controlling limit which ensures that a specified emission level is achieved during a typical peak ozone season day. The much less stringent daily maximum limit ensures that the 30-day average is not manipulated to allow higher NO_x emissions on a single day when ozone may be a problem. An annual limit can not assure the level of control required on the hot summer days when ozone is most likely to form. For example, a cost effective compliance strategy with annual limits would be to import additional power and thereby reduce operations and emissions within HGA during the non-peak ozone season. Then, when meeting the peak electric demands of a hot summer day, the peaking units would be free to emit uncontrolled, adding to ozone levels. There would be a strong economic incentive to operate in this manner, because the peaking units include both the least efficient and oldest equipment, for which it is harder to justify adding emission controls. The system cap addresses the ozone problem while allowing the source owners to determine the most cost effective compliance strategy. For these reasons the commission has determined that the daily and monthly limits are necessary elements of the HGA SIP.

Note that the commission has modified the system cap requirements in §117.210 to exclude cogeneration units whose electric output entirely serves one or several dedicated industrial customers, except when the industrial customers are not operating. These sources are base load sources and are not operated at higher levels on hot summer days to meet electric demand and would not contribute additional emissions during these periods.

The commission disagrees that these daily and monthly limits render the ability to trade meaningless because trading can still be useful to meet annual limits. As discussed in a previous response, in a future rulemaking, the commission may develop system cap trading rules for EGFs in HGA which would enable trades to occur among companies. This development would enhance the flexibility of cap and trade compliance.

Sierra-Houston generally opposed the concept of the cap and trade system and stated that it allows some sources to escape reductions. An individual commented that the cap and trade program should be limited in duration and credits should be generated and used only by companies that make actual emission reductions. Two other individuals added that large companies could buy their way out of reductions. Four individuals commented that banking and trading only allows shifting of emissions and that all industries should be required to reduce. Three individuals stated that trading will leave emissions in the poorer neighborhoods.

The commission made no changes to the rule in response to these comments. The cap and trade program is applicable in all eight counties of the HGA area so that reductions are made throughout the nonattainment area. The underlying goal of the program, in conjunction with the Chapter 117 limitations on point source emissions, is to reduce the overall amount of NO_x emitted from point sources by approximately 90%. This reduction of NO_x will then reduce the formation of ozone in the area. The reductions of NO_x and the formation of ozone are not localized problems in the way that VOCs can be. NO_x itself does not have a health impact on nearby neighborhoods. The reductions of NO_x emissions will benefit the nonattainment area as a whole by reducing the amount of ozone formed in the atmosphere.

The cap and trade program is designed to give owners the option of making reductions or purchasing additional allowances. If allowances are for sale, that means the holder of those allowances did not actually emit the amount of NO_x that it had historically. This in turn means that a facility using allowances in lieu of making real reductions is able to do so because another facility in the same area has lowered its emissions by the same amount. Because there will be a finite number of allowances available the overall emissions in the HGA area, NO_x will remain at levels that are necessary to demonstrate attainment of the ozone standard. As the implementation schedule proceeds, the HGA area will have fewer allowances available on the market which means that some reductions are likely to occur at all facilities as emission standards are tightened and allowances become more expensive.

The commission believes that the flexibility provided by the trading program provides the commission, in part, the ability to require the level of reductions required of the point sources in the HGA area.

TIP, Chevron, Dow, Dynegy, Entergy, Enterprise, Equistar, ExxonMobil, Goodyear, Lyondell, NASA, Peco, Phillips 66, REI, Texas Eastern, TxOGA, TPIEC, Valero, and BCCA commented that the proposed NO_x reductions that the cap and trade rule are intended to implement are not technologically or economically feasible and will not result in an economic incentive under the cap and trade rule because there will be insufficient surplus allowances. The cap and trade system should be based on current California point source controls, which are the most stringent achieved in practice. TCC commented that Emission Specifications for Attainment Demonstrations should be achievable with proven technology.

The commission made no changes in response to these comments. Point source NO_x reductions in the range of 90% require the combined use of combustion modification and flue gas controls on the majority of large combustion units. The capabilities of both combustion modifications and flue gas controls are well documented in the NO_x control literature, including the EPA ACTs, papers at numerous meetings of research and trade organizations for industry, NO_x control vendors, constructors, and the government. These documents report combustion-based reductions from minimal to over 90%, and flue gas controls in the range of 75% to 95%. Reduction capabilities as reported in the literature continue to improve and technology has developed rapidly since the late 1980s when a number of California districts set retrofit NO_x control standards. Both combustion modifications and flue gas cleanup are established technologies. Technology is replicable, so in a true sense, the first successful SCR project was sufficient to demonstrate its feasibility. With more than 500 applications of SCR reported by 1997 and growing rapidly, in many different exhaust streams with widely varying degrees of temperature and contaminants, its technical feasibility is not a question. The combination of combustion and flue gas controls can provide overcompliance with the standards in a number of cases and will allow for meaningful choices in the selection of control strategies. Examples of units which have been retrofit to levels below the adopted emission specifications and further details of the technical feasibility of the emission specifications can be found in the analysis of testimony of the Chapter 117 rules published concurrently in a separate section of this issue of the *Texas Register*. Overcontrol on some units will enable others to be under controlled, which will result in substantial cost savings. Although the exact degree of cost savings is not determinable, one vendor has estimated the number of SCRs at 800, rather than the approximately 1200 that the Chapter 117 cost note contemplated. Although the number of SCRs is expected to be unprecedented, the ultimate number installed is virtually certainly going to be lower as a result of the cap and trade rules, representing significant cost savings. The market-based approach embodied in the adopted rules give nearly complete freedom on how to achieve the goals and based on experience from California, will stimulate the development of new and innovative reduction technologies and strategies.

NASA commented that because they have multiple small sources which constitute a major source, it is unlikely that they will have any emission reductions to trade. They stated that the program will create uncertainty for future allowance costs which would create a hardship on an agency that has its budget decided years in advance. They also expressed concern that the compliance time frame was unreasonably short, roughly two years, as opposed to the acid rain or RECLAIM programs.

The rules have been revised to address the concerns of the commenter. NASA operates a number of gas-fired boilers which are subject to the emission specifications. These boilers all operate at relatively low capacity factors. The commission has adopted a less stringent emission standard for low capacity factor units which operate less than 14 days per year, which will reduce NASA's costs of compliance. In addition, the compliance schedule has been lengthened, which will allow NASA at least three years to develop an emission reduction strategy. The adopted compliance time frame allows the maximum feasible time under the federal requirement to attain the ozone standard in HGA by 2007.

FPL commented that the extremely low NO_x emission limitations simultaneously proposed in Chapter 117 means that very few surplus allowances will be available on the market. The proposed requirement to obtain allowances before a new source can operate means that these new sources can only obtain allowances if an existing source shuts down. The proposal therefore does not allow for any growth in the HGA area. FPL recommended that the commission set aside a number of allowances for use by new sources. Enron and Coalition recommended that allowances be set aside for new sources to bring new and cleaner sources into the program.

No changes have been made in response to these comments. The commission believes that sources will be able to generate additional allowances not only through shutdowns, but also by improving emission control technology. The commission also believes that allowing the use of discrete emission reduction credits (DERCs) and mobile discrete emission reduction credits (MDERCs) will allow stationary sources to find flexibility for growth from NO_x sources not subject to the cap and trade program. The commission agrees that the intent of the rule is to stop growth of emissions, but disagrees that the rule will stop economic growth. With cleaner technology always being developed, the commission anticipates that point sources will be able to grow while keeping their emissions low. The commission disagrees that allowances should be set aside for growth as this would create a first come first serve scenario putting undue pressure on staff to determine who should receive allowances first and it could give new facilities sources a significant benefit at the expense of existing entities.

CAAC commented that cap and trade systems have fallen short of anticipated environmental benefits and that the commission should continue with the trading system currently in operation. They also recommend that the commission adopt third party verification of emission credits as opposed to executive director approval which could cause delays in approval.

The rules were not revised in response to these comments. The cap on NO_x emissions provides a finite limit on NO_x which has been demonstrated as a necessary part of the overall HGA attainment strategy. The cap and trade program will limit the total emissions of NO_x from point sources as opposed to the limitation on NO_x emission rates required by the point source rules alone. The commission wishes to provide as much flexibility as possible within these admittedly tight emission standards and believes the cap and trade program provides this. The commission disagrees that executive director verification of credits will cause delays within the system. Such verification can often be accomplished in one business day or less.

CAAC commented that the cap and trade system will encourage purchase of power generated from higher emitting sources outside the area of the program. They also stated that the allocation of allowances is not necessary and credits should only be generated when a source remains below its established cap.

The rules were not revised in response to these comments. The cap and trade program does not prohibit the purchase of power outside the affected area of cap and trade. This will be a business decision of the buyer and will depend on their cost of reducing emissions, allowance availability and cost, and availability of power outside the HGA area. Allowances provide a convenient, flexible, and timely method for facility operators and the commission to track a facility's status in relation to its emission cap.

An individual opposed the cap and trade program based on the argument that it strengthens an argument that there is a right to pollute and that it allows sources to avoid reducing their emissions. The individual supports the command and control method of achieving reductions.

The rules were not revised in response to this comment. The permit system is based on the concept that owners of facilities obtain an authorization to emit contaminants. The preamble clearly states that permits and authorizations are not property rights and are therefore not protected as such under the law. The cap and trade program will not eliminate the need for prior authorization to construct and operate significant sources of air contaminants nor for rules which could be considered command and control strategies.

TIP, Chevron, Dow, Dynegy, Entergy, Equistar, ExxonMobil, GPA, Kinder Morgan, Lyondell, Peco, Phillips 66, REI, TxOGA, TPIEC, TGC, Valero, and BCCA stated that the requirement to trade allowances in whole tons lacks reasoned justification. The number of allowances is rounded up or down whichever provides the holder or buyer less credit. Some credits have been traded with a value of $80,000 per ton and rounding can result in the taking of considerable value. They recommend that trading occur in one-tenth tons. This is consistent with ERC trading. Texas Eastern also recommended allowances be traded in tenths of a ton. TGP recommended that fractions of allowances be rounded up rather than down. During the years of target allowances, rounding down can result in zero allowances.

The commission has modified §101.350(1) to divide allowances into tenths of a ton. The commission agrees that there is a potential for the need to trade and use allowances in smaller quantities than whole tons thus the rule has been revised to state that allowances will be allocated, transferred, or used in tenths of a ton. The rounding methodology was not changed from the normal mathematical rounding procedures however, by allocating, transferring, and using allowances in tenths of tons will reduce the impact of rounding.

An individual commented that the cap should be limited to the central urban county (Harris).

The rules were not revised in response to this comment. The modeled attainment demonstration conducted by the commission indicates that reductions are required over a wider geographic area other than Harris County in order for the Houston/Galveston to attain the ozone standard. As discussed in the background of the preamble to this rule, scientific study has clearly demonstrated that ozone is more of a regional problem than a local one. Emissions from the surrounding seven- nonattainment counties contribute to the ozone formation within Harris county and must be reduced significantly in order for the entire eight-county nonattainment area to demonstrate attainment with the ozone standard. Applying the cap and trade program to the entire eight-county nonattainment area ensures that there is not an excess of allowances available for trade back into the central county.

Enron commented that the cap and trade program should be expanded to areas out of the eight-county Houston/Galveston nonattainment area to promote a high volume of allowance transactions. Kinder Morgan and Pasedena recommended including minor sources in the trading program.

The rules have not been revised based on these comments. The intent of this program is to cap emissions in the HGA area at existing levels. The commission has not yet determined that this restriction is necessary outside of the HGA area. The commission may determine at a later date that including surrounding counties into the cap and trade program would benefit the air quality and help the HGA area reach attainment. The cap and trade program will include minor facilities, with standards under Chapter 117, down to a design capacity of ten tons of NO_x per year. The commission intends to revise the cap and trade rules to include minor facilities at sites that collectively have a design capacity of ten tons per year or more.

BASF commented that the ten tons per year (tpy) applicability threshold for the cap and trade system should apply to accounts or sites rather than individual sources. Because sources under ten tpy would not receive allowances they would be required to meet NO_x emission limits through cost- ineffective controls. They suggest replacing the term "source" in §101.351 with the term "NO_x cap account." TIP, Chevron, Dow, Dynegy, Entergy, Equistar, Peco, Phillips 66, and BCCA commented that the term "source" is used to denote an overall site over the ten-ton applicability trigger but is also used to denote a single emitting unit. TIP, BCCA, Chevron, Dow, Dynegy, Entergy, Equistar, ExxonMobil, Lyondell, Phillips 66, REI, Solutia, Texas Eastern, TxOGA, TPIEC, Valero, and BASF commented that sources not subject to emission specification for attainment demonstration (ESAD) rates under the SIP that can make cost effective reductions should have the option to participate in the cap and trade program and its allowances allocated in the same manner for current ESAD sources.

The rules have not been revised based on these comments. The commission had intended the cap and trade program to apply to all facilities at sites that have emission specifications under Chapter 117 and collectively have a design capacity of ten tons or more of NO_x emissions per year. However, due to the use of the term source in the proposal, that intent was not clear from the rule language. In order to ensure that all potentially impact entities have the opportunity to comment on their inclusion, the commission intends to propose a revision to the cap and trade rule in the near future which would clarify that the applicability of the cap and trade program is determined by the collective emissions at a site and that the ten-ton per year applicability requirement does not apply to individual facilities. Facilities not subject to the cap and trade program will be able to generate DERCS which are allowed to be used along with allowances under the cap and trade system. They will also be able to create and to use ERC under the existing banking program.

Dynegy and RMT recommended replacing the term "design capacity to emit" in §101.351 with "potential to emit." as the terms appear to be identical. Calpine commented that the commission should define the term "design capacity to emit." It is not clear if emissions are pre- or post-control.

There were no changes to the rules in response to these comments. The term "design capacity to emit" refers to the capabilities of particular equipment regardless of enforceable limitations. The term "potential to emit" is a term of art which is commonly used in reference to the Title V operating permits program and means the capability to release air contaminants as limited by pollution control equipment and authorized levels of release. Since there are specific nuances of the term "potential to emit" that do not apply to this program, such as synthetic minors, the commission is not using this term.

TIP, Chevron, Dow, Dynegy, Entergy, Equistar, ExxonMobil, Lyondell, Peco, Phillips 66, REI, TxOGA, TPIEC, Valero, and BCCA believe that one month is an inadequate period to calculate a control period's emissions and compare those emissions to cap and trade activity for the control period to balance the account. They recommend April 1 of the succeeding year as the deadline for reconciling accounts. Calpine and RMT recommended a one month extension to March 1. Calpine and RMT also commented that the deadline of March 31 for submitting compliance reports is too short as CEMS data must be manually quality controlled. They suggest a one month extension.

No changes have been made in response to this comment. It is the commission's intent that facilities should actually have the allowances in their compliance account to cover emissions prior to their actual withdrawal. It is not the commission's intent to allow facilities to emit and then try to obtain allowances after the fact. Although this is not prohibited under the rules, it is discouraged by the limitation of the true-up period to one-month. As proposed, the rules are on the conservative side and will allow facilities a 30-day grace period to obtain allowances to balance emissions. In addition, the final reporting deadline has not been revised and currently parallels the commission's emission inventory reporting guidelines.

TIP, Chevron, REI, TCC, TxOGA, and BCCA commented that the rule should be modified to allow compliance with an emission cap to satisfy both nonattainment new source review and prevention of significant deterioration.

No changes have been made in response to this comment. The commission agrees that the cap is being permanently set at a level for stationary facilities for the HGA area to reach attainment. The commission believes that if all stationary facilities operate under the cap that performing netting and requiring offsets for new or modified facilities may not be necessary to attain and maintain the federal air quality standard. However, because these are specific federal statutory requirements, removing the netting and offset mandates would require amendments to the Federal Clean Air Act. The commission also believes that any facility having major increases of NO_x should undergo a nonattainment/prevention of significant deterioration review to ensure they are meeting BACT or LAER as applicable, regardless of whether the facility operates under the cap.

Calpine and RMT requested clarification or an example where an allowance could be simultaneously used to satisfy an offset requirement as well as used for cap and trade purposes.

The rules were revised based on this comment to clarify the language in §101.352(e). Compliance with the cap and trade program requires industry to retire one allowance for every ton of NO_x emitted. Offset requirements are under a separate program and require in the HGA nonattainment area 1.3 tons of NO_x credits to be retired for every ton of NO_x proposed to be emitted from a new major source or modification in the HGA area. Under these adopted rules, in §101.352(e), and under proposed changes to Chapter 106 as published in the October 20, 2000 issue of the *Texas Register* (25 TexReg 10445) and Chapter 116 as published in the October 20, 2000 issue of the *Texas Register* (25 TexReg 10449), compliance with the NO_x cap and trade program (retiring one allowances for every ton of actual NO_x emissions) may be used for the one-to-one portion of the NO_x offset requirement. The additional 0.3 portion of the NO_x offset requirement may be met by retiring additional NO_x DERCs, MDERCs, ERCs or MERCs. This rule only applies to NO_x and not to other criteria pollutants requiring offsets.

For example, if a new major facility was constructed in the HGA nonattainment area which would emit 100 tons per year of NO_x, the source would have to satisfy the cap and trade requirements by obtaining 100 tons of allowances. Those allowances could also count toward the facility's offset requirement so that only 30 tons of NO_x DERCs, MDERCs, ERCs or MERCs would be needed to satisfy offset requirements for NO_x.

The EPA commented that any baseline for determining allowances should be adjusted downward for any state and federal laws enacted since the last emission inventory used for an attainment demonstration.

The commission has included language in the provision regarding initial allocations, as listed in variable (3) of Figure §101.353(a) to ensure that allowances will not exceed existing federal or state regulations, rules, or permit allowables.

Avista-Steag commented that portions of the allowance calculations for 2003 and 2004 are ambiguous and subject to differing interpretations and requests that the commission provide additional and adequate public notice so that affected parties can determine the effect of the rules and comment meaningfully. TIP and BASF commented that the calculations to achieve equal third reductions must be revised. FPL and LCR commented that the equations reducing a source's allowances do not result in equal third reductions and should be revised. Calpine and RMT commented that the equations did not result in equal third reductions and the wording of the calculation methodology is unclear.

The commission has revised the rule to remove the ambiguity concerning allowance calculations, however, the commission did state in the preamble the clear intent to reduce allowances by a third of the difference between the initial allocation for 2002 and the calculated final allocation for 2005. The commission believes this statement served its intended purpose of soliciting comments on the allocation concept and the need for clarification to the rule language is not sufficient cause for re- notification. The equation in §101.353 has been revised to require all boilers, auxiliary steam boilers and stationary gas turbines within an electric power generator system, as defined in §117.10 to reduce their emissions by an average 44% beginning March 31, 2003, another average 44% by March 31, 2004, and another average 5% by March 31, 2007, for a total of an average 93% overall reductions. All other facilities subject to the cap will be required to reduce their emissions by an average 40% by March 31, 2004, another an average 40% by March 31, 2005, and another average 10% by March 31, 2007, for a average total of 90% reductions.

BASF commented that the commission should clarify what method will be used to determine allowances for a newer source where two years of activity data is not available.

No changes have been made based on this comment. As stated in the response to the previous comment, the rules have been clarified, however, the methodology for new or modified facilities has not changed with the exception of the percentage reduction requirements. Facilities that are not in the 1997 - 1999 inventories and that do not have two years of actual data will receive allowances based on that facility's authorized level as stated in the permit or permit by rule until such time as it accumulates two years of actual data. This method is stated in variables (2)(B) and (3)(B) in Figure 30 TAC §101.353(a).

Avista-Steig encourages the commission to adopt an allowance distribution program based on a source's overall effect on air quality.

No change was made based on this comment. The commission will distribute allowances based on a facility's emissions as adjusted for the required reductions. The commission is seeking to accomplish an overall reduction in NO_x for the HGA area of approximately 90%. The commenter is not clear whether allocations for larger facilities should be reduced in greater proportion than a smaller facility because of the larger facility's greater air quality effect or whether the larger facility should continue to receive more allowances based on its size and activity level or whether different categories of facilities should be treated different. Allowances under the cap and trade program are established under the regional cap for the HGA area. The initial allowances will be based upon historical data while Chapter 117 will determine the final allocation amount.

BCCA, Dow, Dynegy, Entergy, Equistar, ExxonMobil, GPA, Kinder Morgan, Lyondell, Pasedena, Phillips 66, TCC, TPIEC, Valero, and Chevron commented that a consecutive 12-month period would more accurately reflect activity levels and would reduce requests for case-by-case reviews. Kinder Morgan and TGC recommended an alternative where the most representative three year period during the span 1995 - 1999 be used to determine activity level. Chevron commented that the baseline for allocation of allowances should be the six months of highest activity from 1995 to rule promulgation. As an alternative they suggest using an average level of activity determined during periods when equipment is operating as a substitute for periods of equipment turnaround or shutdown in the calculation of allowances. Texas Eastern commented that using an average of three years activity for baseline calculations does not allow for extended maintenance. Calpine and RMT commented that using an activity average for two years will cause a steady loss of allowances due to mechanical outages, economic conditions, or natural disasters. New sources will also reduce the pool of available allowances. Eventually sources may have to curtail activity because of scarcity of allowances. Calpine and RMT recommended that allowances be based on the higher activity level for the first two years of operation. FPL and TCC commented that basing allowances on activity level imposes an additional emission restriction over that contained in Chapter 117 and recommended that allowances be based on permitted or authorized activity levels. Diamond-Koch also recommended that allowances be based on potential or authorized activity levels. TGP recommended using the average of the two highest years of actual activity for 1997, 1998, and 1999. CPS commented that the commission should establish a baseline of the highest activity year since 1990 for the determination of allowances. They suggest 1995 as an alternative because accurate NO_x data is available as that was the first year that CEMS were required for acid rain facilities. The EPA commented that §101.353(a)(4) seems to allow sources to determine the amount of their allowances. The EPA requested the commission address how the cap will be limited to the emission inventory of an EPA approved attainment demonstration.

No changes have been made in response to these comments. The commission has based the SIP strategy on the 1997 emissions inventory. To alleviate restrictions on any one given facility, for example a facility down for maintenance during 1997, the commission chose to use a three-year average to determine the activity level. However, if all facilities were allowed to choose either the highest 12-month or three-year activity level, the cap would be based on activity levels much higher than those used for determining the level of reductions necessary for the HGA area to reach attainment. The commission has chosen to use the 1997, 1998, and 1999 because they are the most recent and should best represent the emissions of facilities currently in operation. As noted in the rules, the executive director may deviate from using the average from these three years in extenuating circumstances.

An individual stated that sources should not be allowed to determine their own activity rate, thus their allowances, and emission inventories are not a reliable source to determine activity.

There have been no changes to the rules in response to this comment. The commission disagrees that facilities will be determining their own activity level. Emissions inventories do not generally contain the activity data that is required by the rule. That is why §101.360 requires that the source owner certify the activity level to the executive director. The commission will evaluate the historical activity submitted by facilities to determine the amount of allowances. The activity data for calculating allocations is primarily annual fuel usage or product output. These parameters are fundamental to most companies' cost and profit structure and are usually verifiable by other data. This information will be audited by commission staff for accuracy based upon historical records, testing, emissions inventory, and other replicable emission calculation methodologies as available.

TIP, BCCA, Chevron, Dow, Dynegy, Entergy, Equistar, ExxonMobil, Lyondell, Phillips 66, REI, TxOGA, TPIEC, Valero, and BASF commented that there is no reasoned justification for the rate of NO_x emission reduction in one-third increments and this rate of reduction is not needed to meet rate-of-progress requirements. TIP and BASF suggested a 10% reduction each year from 2003 - 2006 followed by the target allocation in 2007. Texas Eastern commented that the implementation schedule is too aggressive. TCC commented that the phase in period should be extended until 2007. TGC recommended the rule include an option for sources of less than 25 tons per year to propose an alternative compliance schedule which demonstrates compliance by January 1, 2005. Kinder Morgan recommended that deadline for achieving the initial one-third reduction for interstate pipeline companies be moved from December 31, 2002 to December 31, 2003. This would allow time to obtain necessary approvals for design and construction of the modified facilities. TIP, Goodyear, TxOGA, and GPA commented that a three-year implementation schedule is not technologically practical or economically feasible and recommended a five-year (2002 - 2007) implementation schedule. GPA also suggested that the rule contain a provision for an alternative implementation schedule for IC engines with allowances of 25 tons per year or less. The alternative schedule must demonstrate compliance with the rule by January 1, 2005. An individual stated that the implementation schedule for the cap and trade system is too short and yearly emission reductions do not realistically reflect the operational and planning schedules of companies.

The rules have been revised based on these comments. The commission believes that phasing in compliance with these rules is critical to the success of the program for many reasons including availability of equipment needed to make reductions as well as the need to satisfy the SIP requirement that reductions are made as soon as practicable. The designated attainment year in the HGA area is 2007, and the rules have been revised to require a less rapid reduction of NO_x from affected facilities and allow phase in between 2002 and 2007. The new schedule as described in §101.353 will ensure that NO_x emission from stationary facilities will be reduced to a level necessary to reach attainment.

CAAC commented that the establishment of a final cap should take into account the controls established to date. A 90% reduction may not be feasible for a source currently using best available control technology.

The rules were not revised in response to this comment. The 90% reduction is an estimate of the overall reductions to be achieved from the 1997 emission inventory for stationary facilities throughout the entire HGA nonattainment area. The actual requirement which applies to each facility depends upon the type of facility and is stated in terms of an emission rate, generally not a percentage reduction. The commission recognizes that some facilities may have made reductions subsequent to that inventory. These facilities would only be required to additionally reduce emission to a point that complies with individual emission specifications contained in the applicable Chapter 117 requirement. In this way, cleaner facilities are not penalized.

Enron and Coalition commented that emission levels under the cap and trade system should not be established by the type of fuel used but rather by the industry type, for example power generation. This will encourage the use cost-effective approaches to emission reductions. Emissions should also be regulated based on output such as lb/MWh to encourage efficiency. Direct credit should be available for the benefits of combined heat and power generation.

The rules were not revised in response to this comment. The adopted cap and trade rules allocate allowances based on the heat input of a facility, not the production output. This is consistent with the methodology used in developing the SIP. Because the cap and trade program is a SIP compliance and flexibility tool for stationary facilities, it is necessary to base the cap and trade program on identical methodology. Credit for the dual generation of heat and power is built into the cap and trade program if this results in reduced emissions. Any facility that achieves a dual result with the same energy input will use less allowances as a result of this efficiency.

The proposal allows sources newly authorized by permit application or permit by rule to receive allowances based on their permitted or actual activity levels. TIP, BCCA, Chevron, Dow, REI, TxOGA, Valero, and BASF support this concept but commented that newly modified sources should be treated identically.

The rules have been revised based on this comment. The commission agrees with this comment and has revised §101.353(a) to refer to new and modified facilities. By "modified facilities" the commission is referring to the modification itself. For example if an existing facility is modified to double its capacity in 1998, the emissions from the original facility will be allocated in the same way as facilities existing before 1997. The increase in emission allowable associated with the modification will be treated as a facility which did not exist before 1997.

Calpine and RMT requested clarification of the term "...the source's emission factor listed in Chapter 117" as it appears in §§101.353(a)(1)(A), 101.353(a)(1)(B), 101.353(a)(2)(B)(i), 101.353(a)(2)(B)(ii), and 101.353(a)(3)(B)(ii). The commission should clarify §101.353(a)(1)(C) to state the deadline for submitting an administratively complete application is January 2, 2001.

The rules have been revised in response to this comment. The revised rules cite the specific sections of Chapter 117 which are relevant. The rules have also been revised to include the deadline of January 2, 2001 for submitting an administratively complete application.

Avista-Steag commented that newer and cleaner facilities should not pay a disproportional amount of the cost to reduce emissions at older facilities. Because new facilities must obtain allowances prior to operation, they must purchase allowances from operating facilities that may have upgraded their equipment to generate surplus allowances. The new facility therefore pays for a portion of the older facility's upgrade. They also stated that the requirement for new electric generating plants to purchase allowances before operation will deter the construction of electric generating capacity in the Houston area because the purchase must be added onto the cost of implementing lowest achievable emission rate controls. ED commented that three to five percent of all allowances be set aside for allocation to operators of sources that carry out qualifying energy efficiency projects in the region.

No change was made based on this comment. Owners that retrofit older facilities can recover some costs through the sale of allowances. The commission intended this as an incentive to reduce emissions from these facilities. While owners of newer facilities must purchase allowances prior to operation, these facilities can be constructed to operate cleaner than the older retro-fitted facilities thus reducing their need for allowances. In some cases, the newer facilities are at an economic advantage in complying with the point source rules due to their ability to install state-of-the-art technology instead of retrofitting older technology. The commission believes this will provide a balanced program that allows owners to make the appropriate business decision for their facility within the framework of the required reductions. The commission disagrees that the need to acquire allowances prior to operation of new facilities will deter the construction of new electric generating capacity. A growing market demand for electricity that would support new generating capacity will allow for a profitable expansion. Operators of facilities that complete energy efficiency projects that directly affect emissions from their facilities will be able to generate allowances based on their emission reductions.

The EPA commented that the rule should contain enforcement provisions to make the rule enforceable and without the provisions the rule cannot be approved. One individual stated that the program does not have a penalty policy.

The rules were revised in response to this comment. In the event that an account does not contain a sufficient number of allowances on February 1, the rules already provide for the automatic subtraction of the amount lacking plus 10% of a facility's exceedence of its allocations from the subsequent year's allocations. Additionally violations of this rule are subject to the normal enforcement actions of the commission for violating rules and regulations which are subject to administrative penalties up to $10,000 per violation per day. This was clarified by adding rule language to §101.353(c). The commission penalty policy is not contained within each rule but is a separate policy implemented by the enforcement branch of the agency. Penalties are not generally detailed in the rule so that enforcement staff has flexibility to make case-by-case decisions.

TIP, Chevron, Dynegy, Entergy, Equistar, ExxonMobil, Lyondell, Phillips 66, REI, TxOGA, TPIEC, Valero, and BCCA commented that allowances should be allocated for a stream of 30 years or more rather than allocated yearly to allow for more fluid trading and a defined period, greater than one year, of overcontrol or undercontrol for participating sites. This methodology would also simplify allocations.

The commission has made no changes to the rule in response to this comment. The intent of the HGA SIP, of which this rule is a part, is to attain the ozone standard. Subsequent to attainment, the commission will be responsible for a maintenance plan for HGA air quality. Allocation of allowances on a yearly basis provides the commission the ability to plan and anticipate effects on air quality. It also provides the commission an enforcement mechanism for facilities whose actual emissions exceed the allowances in their compliance account through the reduction of subsequent yearly allocations. The commission has decided not to allocate a stream of allowances into the future for many reasons including the amount of tracking that would entail for agency staff. The commission disagrees that this methodology would simplify allocations. However, nothing would not prohibit facilities from entering private agreements for the sale of future allocations or rights to allocations.

The EPA stated that in the absence of an established procedure for the executive director to approve deviations from allocation methodology, such deviations will require the EPA approval.

There have been no changes to the rule in response to this comment. The executive director plans to detail the factors which may be considered for deviation from allocation methodology in a guidance document which will be shared with the EPA upon its completion. The executive director plans to limit deviations to extraordinary circumstances. The commission has revised the rule to include a deadline for applications for deviation.

TIP, BCCA, Chevron, Dow, Dynegy, Entergy, Equistar, ExxonMobil, Lyondell, REI, TxOGA, TPIEC, Valero, and BASF commented that the commission should clarify that target allocation based on 1997 - 1999 activity will not change despite shutdowns, replacements or changes to equipment. Calpine and RMT stated that the proposal does not address what happens to allowances allocated to sources that shut down during a control period. They suggest retaining the allowances in the emission cap to help sustain economic activity and promote replace of older units with new, cleaner equipment

The rules have been revised based on this comment. The commenters are correct, the allocations will not change unless the program is revised in the future. The commission has added §101.353(h) to state and clarify that allowances will not change despite shutdowns, replacements, or changes to equipment assuming the allowances are based on historical activity levels. However, facilities which obtain allocations based upon allowables but never constructs will not continue to receive allocations.

BCCA, Phillips 66, RAQCG, and Chevron supports an additional incentive program that would provide funds for use by a wide range of source categories to assist compliance with SIP required reductions. Such a fund would be competitive and, if funded by private sources, would provide appropriate credit or benefit to the parties providing the funding. The plan should incorporate broad executive director authority to approve credits on a case-by-case basis.

The rules were not revised based on this comment. The establishment of a private fund for pollution control projects is outside the scope of the adopted rules and will be left to the discretion of affected industries. If projects completed under such a fund result in emission reductions then the subsequent surplus allowances may be banked or traded under the provisions of this adoption. The rules are intended to provide market-based flexibility in meeting emission standards, and the commission prefers to let the market set the cost of allowances.

Calpine and RMT commented that rule language should be added to specify that banked allowances will be deducted from accounts before subtracting allowances calculated under §101.353.

The commission revised §101.354 based on this comment, however the rule was revised to require allowances most recently allocated to be subtracted from the compliance account prior to other allowances. By first subtracting allowances issued for a facility's current control period and limiting the life of banked allowances to one-year the commission prevents an accumulation of banked allowances in compliance accounts that would soon jeopardize the overall system cap. The subtraction of newer credits first ensures that facilities can't rotate or accumulate credits to circumvent the one-year carryover limit.

BASF, BCCA, Chevron, Dow, Dynegy, Entergy, Equistar, ExxonMobil, Lyondell, LCR, Peco, Phillips 66, REI, TCC, TxOGA, TPIEC, Valero, and TIP commented that emission reduction credits (ERCs) should be convertible to allowances and the proposal lacks reasoned justification why this is not allowed. By definition all recognized emission credits are real, quantifiable, and surplus to the SIP. Diamond-Koch recommended including a method of converting ERCs to DERCs for use as allowances.

No change has been made based on this comment. ERCs and MERCs were intentionally excluded from §101.356(f) because they would allow a permanent increase to the NO_x emission cap that was determined necessary for the HGA area to reach attainment of the ozone standard. DERCs and MDERCs were included to provide additional flexibility to the cap because their use would be short term and not permanent. Additionally, the use of DERCS is limited during the years 2005, 2006, and 2007 to ensure that the compliance monitoring is not impacted. For these reasons, the rule was also not revised to allow ERCs to be converted into DERCs.

TIP, Chevron, Dow, Dynegy, Entergy, Equistar, ExxonMobil, Lyondell, Phillips 66, REI, TxOGA TPIEC, Valero, and BCCA commented that the existing discrete emission reduction credit (DERC) trading rules require a 10% environmental contribution and a 5% compliance margin. This requirement has been extended to the use of DERCs in lieu of allowances. They stated that there is not a reasoned justification for this requirement and that it is not necessary to meet a region wide cap.

The commission revised §101.356 based on this comment. The commission agrees that the cap was set at a level necessary for stationary facilities as part of the overall attainment strategy for the HGA nonattainment area. The requirement of retiring an additional 10% of DERCs and MDERCs for an environmental contribution and an additional 5% for a compliance margin is not required when using DERCs and MDERCs in lieu of allowances under the HGA cap and trade program.

TIP, Chevron, Dow, Dynegy, Entergy, Equistar, ExxonMobil, Lyondell, Pasedena, Peco, Phillips 66, REI, TxOGA, TPIEC, Valero, and BCCA commented that the rule should contain a provision allowing volatile organic compound (VOC) reductions in the place of NO_x allowances where the VOC reductions are demonstrated to reduce ozone an equal amount.

The commission has modified §101.356 based on this comment. The rule now states that VOC DERCs or MDERCs may be used in lieu of NO_x allowances provided that a demonstration has been made and approved by the executive director and the EPA to show that the use of VOC DERCs or MDERCs is equivalent to the use of NO_x allowances in reducing ozone.

ED commented that sources subject to the cap and trade program should not be able to use DERCs and MDERCs generated outside the area of program applicability.

The rules were not revised in response to this comment. The commission agrees that only DERCs and MDERCs generated in the HGA nonattainment area may be used under the cap and trade program until such time as a demonstration is made a approved to show that credits generated elsewhere improve the air quality within the nonattainment area. This ensures that any emissions in excess of the cap are compensated for in the same air shed. The restriction may already be found in Chapter 101, Subchapter H, Division 4 and applies to credits used under the cap.

The EPA commented that the commission should justify the use of mobile emission credits to meet cap allowances for stationary sources.

The commission has made no changes in response to this comment. The commission believes that any reduction that is quantifiable, surplus, and real regardless of the source will result in an improvement in air quality. The commission further believes that if a reduction occurs that is not relied upon as a reduction in the SIP, and if that reduction is not required by local, state, or federal rules and regulations, then that reduction is truly surplus to the SIP and may be available for use by facilities subject to SIP requirements for flexibility.

The commission has taken measures to ensure that use of credits under the cap will not impact the attainment demonstration. ERCs and MERCs were intentionally excluded from use in the cap and trade program because they would allow a permanent increase to the NO_x emission cap that was determined necessary for the HGA area to reach attainment of the ozone standard. DERCs and MDERCs were included to provide additional flexibility to the cap because their use would be short term and not permanent. Additionally, the use of DERCS is limited during the years 2005, 2006, and 2007 to ensure that the compliance monitoring is not impacted. The ability to use DERCs, especially MDERCs, will also encourage the development of cleaner technologies for NO_x emissions which are not covered by the cap and trade system. The commission will audit the cap and trade program on a three year cycle and that audit will include a determination on the effect of using discrete credits in the program.

The EPA commented that the commission should determine at the end of each year the effectiveness of the regulation in meeting the emission cap. One individual stated that the program does not have an ongoing evaluation of its benefits. TxOGA and

Valero recommended the cap and trade program contain provisions for executive director review and modification, including cost thresholds for allowances, if the program does not provide the intended flexibility.

The commission has added §101.356(g) based on the EPA's comment. The new subsection modifies the cap and trade rule to require an audit of the program every three years. The executive director will also complete a thorough review of account activity, including quantification of actual emissions, every year. Any necessary rule changes to improve the cap and trade program will be made in response to the results of the audit. Since the overall cap will be shrinking, compliance with the cap will mean a reduction in actual emissions. Additionally, as noted in the SIP, the commission is planning to perform a mid-course review of the entire SIP in the 2003 - 2004 time-frame. At that time the commission will have information regarding the effectiveness of the cap and trade program, especially as it applies to certain utilities. The commission does not believe that it is appropriate to identify cost thresholds now which would be used to evaluate the flexibility provided by the program in the future.

ED recommended that the commission closely follow the guidance in the EPAs publication of "NO_x Budget Trading Program for State Implementation Plans" in order to gain approval of the plan from the EPA. They also stated that the program should be reviewed after three years to determine its effectiveness in reaching the NO_x emission target.

The rules were revised in response to this comment. The commission reviewed the EPA guidance and has based this adoption on methodology that is approvable by the EPA. The commission has also responded to the EPA comments regarding this adoption. The commission has added §101.356(e) to require an internal program audit every three years to evaluate the effectiveness of the cap and trade program.

CAAC commented that allowances should only be banked for one-year and that there should be no credit for curtailment of activity.

The rules were not changed in response to this comment. The proposal requires that banked allowances expire after one-year. If curtailment of activity results in reduced emissions and thus, unused allowances, those allowances may be banked or traded within the requirements of this division. The cap for stationary facilities was set at a level necessary as part of an overall strategy for the HGA area to reach attainment. It is the commission's intent to allow unrestricted use of allowances regardless of why they were not used. This would include a facility curtailing its operations so as to not use all of its allowances. One typical concern with curtailment of activity is that it is temporary and should not be creditable as an ERC. However, since allowances are for one- year only, that concern is not relevant. Another concern has been that the activity is simply shifted to other facilities. However, since the emissions from point sources are capped that concern is addressed as well.

ED commented that the commission should require emission monitoring no less stringent than that required under the federal acid rain program.

The rules were not revised in response to this comment. The cap and trade program has no specific monitoring requirements. Facilities participating in the program use or will be required to use, if applicable, monitoring methods required by other state rules and regulations to quantify their actual emissions. The federal acid rain program applies to a more discrete group of facilities so creating emission monitoring requirements is more meaningful. However, NO_x point sources vary widely and monitoring requirements should be made in the rule that addresses each category of sources.

TIP, Chevron, Dow, Equistar, REI, TxOGA, Valero, and BCCA commented that the installation of enhanced monitoring equipment should be delayed until the cap and trade target allocation year of 2005, and there is no reasoned justification for advancing the monitoring requirement to 2001, well ahead of the substantive reductions needed for attainment.

The rules have been changed in response to this comment. The commission proposed a December 31, 2001 compliance date for installation of emissions monitors and fuel meters in order to improve the consistency of the value of a NO_x allowance at the start of the trading program and to improve the inputs used in the commission's air quality planning tools. However, the proposed schedule did not take into account the practicalities identified by the commenters. Both PEMS and CEMS vendors indicated that the number of monitors required in one-year would strain their abilities to provide the equipment. The owners identified clear benefits of installing the monitors in conjunction with the control equipment. If a CEMS is installed before the flue gas controls are fully constructed, the CEMS will probably need to be uninstalled during construction and possibly relocated after NO_x controls. A PEMS will need to be retrained after the installation of control equipment. Phasing in CEMS/PEMS with the emission control equipment is a more rational and cost effective approach and the commission has modified §117.520(c) to reflect this. Therefore, the rules have been revised to require that the monitors will be phased over a four and one-quarter year period, at the installation of emission controls or March 31, 2005 if construction of controls has not commenced. This phase-in will achieve the end result benefits of specified emissions reduction by March 31, 2005. Because the first reduction period has been extended to March 31, 2005, the greater uncertainty about NO_x emissions in the first two years of the program (compared to monitors in place by 2002) will be of less consequence.

TIP, TxOGA, Valero, and REI commented that the rule should allow the documentation of allowance trading be accomplished electronically in keeping with modern commercial practice.

No change was made in response to this comment. The commission agrees with this comment but it currently limited by available resources. The commission intends to review the feasibility of implementing this type or similar tracking as resources become available.

Discrete Emission Reduction Credits Comments

FPL requested clarification as to whether a DERC has an indefinite life or expires after one-year if it is used as a banked allowance under the cap and trade program. CPS requested clarification on whether a DERC has an indefinite period of existence or expires after 60 months as does an ERC.

No changes have been made in response to this comment. DERCs are quantified as a mass of emissions and may be used until they are gone. Unused DERCs do not expire after one-year as do allowances under the cap and trade program. Nor do they expire after 60 months as unused ERCs do.

CPS commented that §101.373(f)(8)(B) be modified to allow the use of DERCs by any facility regulated under Chapter 117.

No changes have been made in response to this comment. Section 101.373(f)(8) simply defines the calculation methodology for

Chapter 117 sources. It does not determine which sources may utilize banking to meet Chapter 117 requirements. The availability of the option to use banking is determined in the section of the commission's rules which applies the control requirement. For facilities not already allowed to utilize credits under Chapter 117, a change would require revisions to the applicable section of Chapter 117.

CPS commented that the formula in §101.373(f)(8)(B) for calculating DERCs seems to be unnecessary and meaningless because there is no definition for "proposed level of activity" or "proposed emission rate."

The rules were revised based on this comment. The definition of "level of activity" was added to §101.370. The commission believes that it is clear that "proposed" refers to the project being proposed for the generation of credits.

CPS and TXU commented that the commission should remove the restriction against the use of DERCs during ozone season in areas of ozone seasons of less than twelve months.

The rules were not changed in response to this comment. It is crucial in attainment with the ozone standard that facilities not be able to make reduction outside of the ozone season which may be used during the ozone season. This is especially true for sources that have their peak usage during months when ozone exceedances are most likely.

Sierra-Houston opposed the trading of DERCs outside the area in which they are generated and stated that each airshed should make its own reductions.

The commission has made no changes in response to this comment. DERCs may be traded from nonattainment counties to attainment counties and among attainment counties. Since the area of use is in attainment with the federal air quality standards, such trading should not harm air quality in these areas and could help reduce problems in nonattainment areas if the reductions are made there. DERCs and MDERCs may only be generated and used in nonattainment areas and no trading may occur between nonattainment areas unless it is shown that emission reductions in the county of generation will improve air quality in the nonattainment area of use.

Sierra-Houston opposed the creation of MERCs.

The commission has made no change to the rules in response to this comment. The generation and use of MERCs and MDERCs provides additional flexibility for both mobile and stationary sources without impeding progress toward air quality goals. Additionally, allowing for MERC and MDERC will help to encourage new mobile source emission reductions technologies which are badly needed. The emergence of these technologies may allow for requirement of them in the future if they are needed to meet the NAAQS.

Sierra-Houston oppose DERCs being used to exceed permit allowables.

The commission has made no change to the rules in response to this comment. The ability to use DERCs to exceed permit allowables is very limited. It is meant for temporary, short-term increases only. There are restrictions on use of discrete credits in §101.373(f)(7) to protect against the potential health impact of the increased uses. Facilities increasing their emissions by use of DERCs may be subject to a health effects review for any increase in emissions. Any review would be conducted independently of the trade and can result in a restriction on the use of credits regardless of the amount of credits transferred during the trade.

SUBCHAPTER A. GENERAL RULES

30 TAC §101.29

STATUTORY AUTHORITY

The repeal is adopted under Texas Health and Safety Code, TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to develop a plan for control of the state's air; §382.017, which provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA, and 42 USC, §7410(a)(2)(A), which requires SIPs to include enforceable emission limitations and other control measures or techniques, including economic incentives such as fees, marketable permits, and auction of emission rights.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009071
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-6087

♦ ♦ ♦

SUBCHAPTER H. EMISSIONS BANKING AND TRADING

DIVISION 1. EMISSION CREDIT BANKING AND TRADING

30 TAC §§101.300-101.304

STATUTORY AUTHORITY

The new sections are adopted under Texas Health and Safety Code, TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to develop a plan for control of the state's air; §382.017, which provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA, and United States Code, §7410(a)(2)(A), which requires SIPs to include enforceable emission limitations and other control measures or techniques, including economic incentives such as fees, marketable permits, and auction of emission rights.

§101.300. Definitions.

The following words and terms, when used in this division, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Activity--The amount of activity at a source measured in terms of production, use, raw materials input, vehicle miles traveled (VMT), or other similar units that have a direct correlation with the economic output and emission rate of the source (i.e., mass emitted per unit of activity).

(2) Actual emissions--Actual emissions as of a particular date shall equal the total emissions during the selected time period, using the unit's actual daily operating hours, production rates, types of materials processed, stored, or combusted during the selected time period.

(3) Applicable emission point--The source which is either generating an emission reduction or using an emission credit.

(4) Area source--Any source included in the agency emissions inventory under the area source category.

(5) Baseline--Emissions that occur prior to an emission reduction strategy, considering all limitations required by applicable state and federal regulations. The baseline may not exceed the quantity of emissions reported in the most recent year of emissions inventory used for state implementation plan (SIP) determinations.

(6) Baseline activity--The source's level of activity based on the unit's actual daily operating hours, production rates, or types of materials processed, stored, or combusted averaged over any consecutive two calendar year period following or including the most recent year of emissions inventory used for SIP determinations or subsequent year(s) which precede the emission reduction strategy or credit use period. For sources in existence less than 24 months or not having two complete calendar years of activity data, a shorter time period of not less than 12 months may be considered by the executive director.

(7) Baseline emission rate (BER)--The source's rate of emissions per unit of activity during the baseline activity period.

(8) Baseline emissions--The source's total actual emissions based on the product of baseline activity and BER.

(9) Certified--Any emission reduction that is determined to be creditable upon review and approval by the executive director.

(10) Curtailment--A reduction in activity level at any stationary or mobile source.

(11) Emission Credit--An emission reduction credit (ERC) or mobile emission reduction credit (MERC).

(12) Emission Reduction--An actual reduction of emissions from a stationary or mobile source.

(13) Emission reduction credit (ERC)--A certified emission reduction that is created by eliminating future emissions, quantified during or before the period in which emission reductions are made, and expressed in tons per year.

(14) Emission reduction strategy--The method implemented to reduce the source's emissions which are surplus.

(15) Generator--The owner or operator of a source that creates an emission reduction.

(16) Mobile emissions baseline--Mobile emissions that occur prior to a mobile emission reduction strategy, considering all limitations required by applicable state and federal regulations. A valid mobile emission baseline can be calculated by either using measured emissions of an appropriately sized sample of the participating mobile sources using an approved United States Environmental Protection Agency (EPA) test procedure or by using estimated emissions of the participating mobile sources using the most recent edition of EPA's on-road or non-road mobile emissions factor models, or other model as applicable. To ensure that mobile credits are surplus, mobile source baseline emissions estimates for each year of the proposed mobile source control program must be the same as, or lower than, those used, or proposed to be used, in the SIP in which the control program is proposed.

(17) Mobile emission reduction credit (MERC or mobile credit)--A credit representing the amount of emission reductions from a mobile source strategy. These emission reductions are voluntary and must be in addition to compliance with requirements of state and federal regulations. MERCs are any enforceable, permanent, and quantifiable emission reduction (exhaust and/or evaporative) generated by a mobile source, which has been banked in accordance with the rules of the commission. MERCs can be banked, purchased, traded, and sold to meet clean air mandates for specified air programs, and MERCs may be applied to the emission reduction obligations of another air quality source or to air quality attainment goals. MERCs are expressed in tons per year.

(18) Mobile source--On-road (highway) vehicles (e.g., automobiles, trucks and motorcycles) and non- road vehicles (e.g., trains, airplanes, agricultural equipment, industrial equipment, construction vehicles, off-road motorcycles, and marine vessels).

(19) Mobile source baseline activity--Will be based on an estimate for each year for which the credits are to be generated. After the initial year, the annual estimates should reflect:

(A) the change in the mobile source emissions to reflect any deterioration in the emission control performance of the participating source;

(B) the change in the number of mobile sources resulting from normal retirement or attrition, and the replacement of retired mobile sources with newer and/or cleaner mobile sources;

(C) the change in usage levels, hours of operation or VMT in the participating population; and

(D) the change in the expected useful life of the participating population.

(20) Mobile source baseline emission--The source's total actual mobile source emissions based on the product of mobile source action and the mobile source emissions rate.

(21) Most stringent allowable emissions rate--The emission rate of a source, considering all limitations required by applicable local, state, and federal regulations.

(22) Ozone season--The portion of the year when ozone monitoring is federally required to occur in a specific geographic area.

(23) Permanent--An emission reduction that is long-lasting and unchanging for the remaining life of the source. Such a time period must be enforceable.

(24) Protocol--A replicable and workable method of estimating emission rates or activity levels used to calculate the amount of emission reduction generated or credits required for stationary or mobile sources.

(25) Quantifiable--An emission reduction that can be measured or estimated with confidence using replicable methodology.

(26) Real reduction--A reduction in which actual emissions are reduced as opposed to a reduction in allowable emissions.

(27) Shutdown--The permanent cessation of an activity producing emissions at a facility.

(28) Source--As defined in §101.1(90) of this title (relating to Definitions).

(29) Surplus--An emission reduction that is not otherwise required of a source by any local, state or federal law, regulation, or agreed order.

(30) User--The owner or operator of a source that acquires and uses emission credits to meet a regulatory requirement, demonstrate compliance, or offset an emission increase.

§101.302. General Provisions.

(a) Applicable pollutants. Reductions of volatile organic compounds (VOCs) and nitrogen oxides (NO_x) may qualify as emission credits. Reductions of other pollutants do not qualify as emission credits under this division. Reductions of one pollutant may not be used to meet the requirements of another pollutant, except at such time as urban airshed modeling demonstrates that one ozone precursor may be substituted for another, subject to executive director and the United States Environmental Protection Agency approval.

(b) Emission reduction requirements.

(1) emission reduction credits (ERCs) are generated from reductions beyond those required. To be certified as an emission credit, an emission reduction must be enforceable, permanent, quantifiable, real, and surplus. The emission credit must be surplus at the time it is created, as well as when it is used. The certified reduction must have occurred after the most recent year of emissions inventory used for state implementation plan (SIP) determinations for VOC and NO_x, and the source's annual emissions prior to the emission credit application must have been reported or represented in the emissions inventory used for SIP determinations.

(2) mobile emission reduction credits (MERCs) are generated from reductions beyond those required, and derived from a calculation of the annual difference between the mobile source emissions baseline and the projected emissions level after the MERC strategy has been put in place. To be certified as a MERC, an emission reduction must be enforceable, permanent, quantifiable, real, and surplus. The emission credit must be surplus at the time it is created, as well as when it is used. The certified reduction must have occurred after the most recent year of emissions inventory used for SIP determinations for VOC and NO_x, the mobile source's emissions must have been represented in the emissions inventory used for SIP determinations, and the applicable mobile sources must have been included in the attainment demonstration baseline.

(3) Emission reductions from a source which are certified as emission credits under this division cannot be recertified in whole or in part as credits under another division within this subchapter.

(c) Eligible sources. The following sources are eligible to generate emission credits:

(1) stationary sources (including area sources);

(2) any mobile source;

(3) any stationary source (including area sources) or mobile source associated with actions by federal agencies under §101.30 of this title (relating to Conformity of General Federal Actions to State Implementation Plans).

(d) Life of an emission credit.

(1) If an ERC is used prior to its expiration date, the ERC is effective for the life of the applicable user source.

(2) Effective January 2, 2001, an ERC is available for use for 60 months from the date of the emission reduction except to the extent regulatory changes occur after the date of reduction that reduce the certified amount or invalidate the entire reduction for affected emission points. ERCs certified or applied for prior to January 2, 2001 shall be available for use for 120 months from the date of the emission reduction except to the extent regulatory changes occur after the date of the emission reduction that reduce the certified amount or invalidate the entire reduction for affected emission points.

(e) Geographic scope. Only emission reductions generated in ozone nonattainment areas can be certified. The trading of emission credits may be discontinued by the executive director in whole or in part and in any manner, with commission approval, as a remedy for problems resulting from trading in a localized area of concern. An emission credit must be used in the nonattainment area in which it is generated unless:

(1) a demonstration has been made and approved by the executive director and the United States Environmental Protection Agency (EPA) to show that the emission reductions achieved in another county, state, or nation provide an improvement to the air quality in the county of use; or

(2) the emission credit was generated in an ozone nonattainment area which has an equal or higher nonattainment classification than the ozone nonattainment area of use, and a demonstration has been made and approved by the executive director and the EPA to show that the emissions from the ozone nonattainment area where the emission credit is generated contribute to a violation of the national ambient air quality standard in the ozone nonattainment area of use; or

(3) the user has obtained prior written approval of the executive director and the EPA.

(f) The registry. All emission credit generators and users must register with the executive director. A notice submitted by a generator or user will be posted to the registry. The registry will assign a unique number to each certificate which will include the amount of emission reductions generated. The registry will maintain current listings of all credits available or used for each ozone nonattainment area.

(g) Recordkeeping. The user must maintain a copy of all notices and backup information submitted to the registry during, and for at least two years after, the beginning of the use period. The user must also make such records available upon request to representatives of the executive director, United States Environmental Protection Agency (EPA), and any local enforcement agency. The records shall include, but not necessarily be limited to:

(1) the name, emission point number, and facility identification number of each unit using emission credits;

(2) the amount of emission credits being used by each unit; and

(3) the specific number, name, or other identification of emission credits used for each unit.

(h) Public information. All information submitted with a notice or report regarding the nature and quantity of emissions associated with the use or generation of an emission credit is public information and may not be submitted as confidential. Any claim of confidentiality for this type of information, or failure to submit all information, may result in the rejection of the emission reduction. All non-confidential notices and information regarding the generation, use, and availability of emission credits may be obtained from the executive director.

(i) Authorization to emit. An emission credit created under this division is a limited authorization to emit VOC and/or NO_x, unless otherwise defined, in accordance with the provisions of this section, the Federal Clean Air Act, and the Texas Clean Air Act, as well as regulations promulgated thereunder. An emission credit does not constitute a property right. Nothing in this division may be construed to limit the authority of the commission or the EPA to terminate or limit such authorization.

(j) Program participation. The executive director has the authority to prohibit an organization from participating in emission credit trading either as a generator or user, if the executive director determines that the organization has violated the requirements of the program or abused the privileges provided by the program.

§101.303. Protocols.

(a) All source categories must use a EPA approved protocol if one exists for the applicable source. If the source wants to deviate from an EPA approved protocol, EPA approval is required before the protocol can be used.

(b) If an EPA approved protocol does not exist, the following applies.

(1) Emission reduction credits (ERC)--The amount of emission credits in tons per year will be determined and certified based on actual monitoring results, when available, or otherwise calculated using good engineering practices including calculation methodologies in general use in new source review (NSR) permitting. The source must collect relevant data sufficient to characterize the process emissions of the affected pollutant and the process activity level for all representative phases of source operation during the period under which emission credits are created or used.

(2) Mobile emission reduction credits (MERC)--The amount of emission credits in tons per year will be determined and certified based on actual monitoring results, when available, or otherwise calculated using good engineering practices. The generator must collect relevant data sufficient to characterize the process emissions of the affected pollutant, and the process activity level for all representative phases of mobile source operation during the period under which mobile credits are created.

(c) Emission credit generation.

(1) ERCs may be generated using one of the following methods or any other method that is approved by the executive director:

(A) the permanent shutdown of a facility which causes a loss of capability to produce emissions;

(B) the installation and operation of pollution control equipment which reduces emissions below the level required of the emission source;

(C) a change in a manufacturing process which reduces emissions below the level required of the emission source;

(D) the permanent curtailment in production, which reduces the source's capability to produce emissions;

(E) pollution prevention projects that produce surplus emission reductions.

(2) MERCs may be generated by any mobile source emission reduction strategy that creates actual mobile source emission reductions under this rule, and subject to the approval of the commission.

(d) Emission credit calculation.

(1) The quantity of ERCs is determined by subtracting the source's new allowable emission limit (tons per year) from the emission source's baseline emissions. The source's new allowable emission limit equals the enforceable emission limit for the applicable emission point after the emission reduction strategy has been implemented.

(2) The quantity of MERCs must be calculated from the annual difference between the mobile source emissions baseline and the projected emissions level after the MERC strategy has been put in place. The projected emissions must be based on the best estimate of the actual in-use emissions of the replacement or substitute on-road or non-road vehicles or transportation system. Any estimate of a projected annual mobile source emissions level based on an assumption of reduced consumer service or transportation service would not be allowed without the support of a convincing analytical justification of the assumption. Emission baselines for quantifying MERCs should include the following information and data as appropriate, but not be limited to:

(A) the emission standard to which the mobile source is subject or emission performance to which the mobile source is certified;

(B) the estimated or measured in-use emissions levels per unit of use from all significant mobile source emissions sources;

(C) the number of mobile sources in the participating group;

(D) the type or types of mobile sources by model year;

(E) the actual or projected activity level, hours of operation or miles traveled by type, and model year; and

(F) the projected remaining useful life of the participating group of mobile sources.

(3) Emission credits cannot be generated from a source if the emissions have been transferred from that source to another source.

(e) Emission credit registration and certification.

(1) Stationary sources with potential ERCs must submit an ERC application (EC-1 Form), within 180 days of the implementation of the emission reduction strategy to the executive director. Sources that have implemented a strategy prior to the effective date of this rule, must submit an application by June 1, 2001. Applications will be subjected to a review to determine the credibility of the reductions. Reductions determined to be creditable will be certified by the executive director and an ERC certificate will be issued to the owner.

(2) Mobile sources with potential MERCs must submit an emission credit application (EC-1 Form), within 180 days of implementation of the strategy to the Executive director if an obligation is exceeded, or if it is clearly demonstrated that actual mobile emission reductions are generated. Sources that have implemented a strategy prior to the effective date of this rule, must submit an application by June 1, 2001. The commission will then issue a MERC certificate(s) to the person, company, business, organization, or public entity generating the mobile emission reduction, upon approval of the application. A MERC certificate will be issued by the executive director which indicates the total amount of certified emission credits, the quantity available on an annual basis, and the date upon which the last annualized emission reduction expires.

(3) The application for a stationary source generator must include the following information, where applicable for either an ERC or MERC, on the EC-1 Form for each pollutant reduced at each applicable emission point:

(A) the name, address, county, telephone number, contact person, permit or permit by rule numbers, account number of the generator, and the unique facility identification number and emission point number of the applicable emission points;

(B) the name of the owner and/or operator of the generator source;

(C) the date of the reduction;

(D) a complete description of the generation activity;

(E) for shutdown or permanent curtailment emission reduction strategies, an explanation as to whether production shifted from the shut down facility to another facility in the same nonattainment area;

(F) the amount of emission credits generated;

(G) for volatile organic compound (VOC) reductions, a list of the specific compounds reduced;

(H) the baseline emission activity, baseline emission rate, baseline total emissions, emissions inventory data from the most recent year of emissions inventory used for state implementation plan determinations and emissions inventory data for the two consecutive years used to determine baseline activity for each applicable pollutant and emission point;

(I) the most stringent emission rate and the most stringent emission level for the applicable emission point, considering all the local, state, and federal applicable regulatory and statutory requirements,

(J) a complete description of the protocol used to calculate the emission reduction generated;

(K) the actual calculations performed by the generator to determine the amount of emission credits generated; and

(L) a statement that the emission reductions on which the emission credits are based are real, surplus, and are based on an eligible emission reduction strategy listed in subsection (c)(1) of this section.

(4) The application for a mobile source strategy must include the following information, where applicable for either an ERC or MERC, on the EC-1 Form for each pollutant reduced at each applicable mobile source strategy:

(A) the name, address, county, telephone number, and contact person;

(B) the name of the owner and/or operator of the generator source;

(C) the date of the reduction;

(D) a complete description of the generation activity;

(E) the amount of emission credits generated;

(F) the mobile source baseline emission activity, mobile source baseline emission rate, mobile source baseline total emissions, and the mobile source strategy;

(G) a complete description of the protocol used to calculate the emission reduction generated;

(H) the actual calculations performed by the generator to determine the amount of emission credits generated; and

(I) a statement that the emission reductions on which the emission credits are based are real, surplus, and based on an eligible emission reduction strategy that is not prohibited.

(5) The applicant will be notified in writing if the executive director denies the emission credit application. The applicant may submit a revised application at any time.

(f) Emission credit practices.

(1) The amount of emission credits in tons per year will be determined and certified, to the nearest tenth of a ton per year.

(2) ERCs are based on EPA methodologies, when available, actual monitoring results, when available, or otherwise calculated using good engineering practices including calculation methodologies in general use and accepted in NSR permitting. The executive director shall have the authority to inspect and request information to assure that the emissions reductions have actually been achieved.

(3) MERCs will be determined and certified using:

(A) EPA methodologies, when available;

(B) actual monitoring results, when available;

(C) otherwise calculated using the most current EPA MOBILE model or other model as applicable; or

(D) otherwise calculated using creditable emission reduction measurement or estimation methodologies which satisfactorily address the analytical uncertainties of mobile source emissions reduction strategies.

(4) All emission credits are deposited in the registry and reported as available credits by the Emissions Banking and Trading Program until they are used, withdrawn, or expire.

(5) Compliance burden and enforcement.

(A) ERCs will be made enforceable by one of the following methods:

(i) amending or altering an NSR permit to reflect the emission reduction and set a new maximum allowable emission limit;

(ii) voiding an NSR permit when an emission source has been shut down;

(iii) registering on a PI-8 form the emission reduction and the new maximum allowable emission limit for any facility which is authorized by a standard exemption or permit by rule;

(iv) registering on an OPCRE-1 Form the emission reduction and the new maximum allowable emission limit for any facility which is not required to have a permit or qualifies for a permit by rule; or

(v) obtaining an agreed order which sets a new maximum allowable emission limit for a facility which is not required to have a permit or qualify for a permit by rule.

(B) MERCs will be made enforceable by one of the following methods:

(i) by registering, on a commission-provided form (MERC-1), that the MERCs are permanent, quantifiable, real, and surplus; or

(ii) by obtaining an agreed order which sets a new maximum allowable mobile source emission limits, which is not required to be implemented by a rule.

(6) Unless there are permits under the same commission account number which contain a condition or conditions precluding such use, ERCs may be used as the following:

(A) offsets for a new source or major modification to an existing source;

(B) mitigation offsets for action by federal agencies under §101.30 of this title (relating to Conformity of General Federal Actions to State Implementation Plans);

(C) an alternative means of compliance with VOC and NO_x reduction requirements as provided in Chapter 115 of this title (relating to the Control of Air Pollution from volatile organic compounds (VOCs)) and Chapter 117 of this title (relating to the Control of Air Pollution from Nitrogen Compounds);

(D) netting by the original applicant, if not used, sold, or otherwise relied upon; or

(E) other provisions as allowable within the guidelines of local, state, and federal laws.

(7) MERCs may only be used for the following purposes:

(A) an alternative means of compliance with VOC and NO_x reduction requirements as provided in Chapters 115 and 117 of this title;

(B) complying with fleet requirements to the extent allowed by the Texas Clean Fleet Program requirements for motor vehicle fleets;

(C) providing offsets for a new major source or major modifications;

(D) mitigation offsets for action by federal agencies under §101.30 of this title; or

(E) other provisions as allowable within the guidelines of local, state, and federal laws.

(8) The calculation of the number of ERCs or of MERCs needed by the user for offsets or for compliance with Chapter 115 or Chapter 117 of this title are as follows:

(A) for emission credits used as offsets, the method for determining the number of emission credits needed by the user for offsets is provided in §116.150 of this title (relating to New Major Source or Major Modification in Ozone Nonattainment Area); or

(B) for emission credits used as compliance with Chapter 114, Chapter 115, or Chapter 117 of this title, the number of emission credits needed should be determined in accordance with the requirements of this section plus an additional 10% to be retired as an environmental contribution; or

(C) for emission credits used to comply with §117.210 of this title (relating to Source Cap) and §117.223 of this title (relating to Source Cap), sources may reduce the amount of emission reductions otherwise required by complying with the following equations instead of the equations in §117.210(c)(1) and (2) and §117.223(b)(1) and (2) of this title.
Figure: 30 TAC §101.303(f)(8)(C)

(D) emission reductions used as compliance with any other applicable program should be determined in accordance with the requirements of the appropriate chapter and section and must contain at least 10% extra to be retired as an environmental contribution.

(9) Review schedule.

(A) For emission credits which are to be used for compliance with the requirements of Chapter 114, Chapter 115, or Chapter 117 of this title, the user must submit a Notice of Intent to Use, (EC-3 Form) at least 90 days prior to the planned utilization of the emission credit. Emission credits may be utilized only after the executive director grant approval of the notice of intent to use.

(B) For emission credits which are to be used as offsets in accordance with Chapter 116 of this title, the user must submit a Notice of Intent To Use Form (EC-3 Form), along with the emission credit certificate when providing the emission credits as offsets.

(10) Emission credits are freely transferable in whole or in part, and may be traded or sold to a new owner any time before the expiration date of the emission credit. The Emissions Banking and Trading Program must be notified by means of an EC-4 Form prior to the transfer. The old certificate must be submitted to the registry. The executive director will issue a new certificate to the emission credit purchaser reflecting the emission credits purchased by the new owner, and a revised certificate to the emission credit seller showing any remaining emission credits available to the original owner. Emission credits may be transferrable only after the executive director grants approval of the transaction.

(11) Emission credits may be withdrawn from the registry by the owner at any time prior to the expiration date of the credit and may be held by the owner. Emission credits may still be used by the original owner as an emission reduction for netting purposes after the emission credits have expired, as provided in §116.150 of this title.

(12) Recording use of emission credits.

(A) Emission credits to be used as offsets in an NSR permit must be identified prior to permit issuance. The original certificate must be submitted prior to operation.

(B) Use of emission credits for purposes other than those specified in subparagraph (A) of this paragraph may not commence until the user has received approval from the executive director. The user must also keep a copy of the emission credit certificate, the notice, and all backup in accordance with §101.303(e) of this section.

(C) If the executive director denies the stationary source's use of emission credits, any person affected by the executive director's decision may file a motion for reconsideration within 60 days of the denial. Notwithstanding the applicability provisions of §50.31(c)(7) of this title (relating to Purpose and Applicability), the requirements of §50.39 of this title (relating to Motion for Reconsideration) may apply. Only a person affected may file a motion for reconsideration.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009072
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-6087

♦ ♦ ♦

DIVISION 3. MASS EMISSIONS CAP AND TRADE PROGRAM

30 TAC §§101.350-101.354, 101.356, 101.358-101.360

STATUTORY AUTHORITY

The new sections are adopted under Texas Health and Safety Code, TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to develop a plan for control of the state's air; §382.017, which provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA, and United States Code, §7410(a)(2)(A), which requires SIPs to include enforceable emission limitations and other control measures or techniques, including economic incentives such as fees, marketable permits, and auction of emission rights.

§101.350. Definitions.

The following words and terms, when used in this division, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Allowance--The authorization to emit one ton of nitrogen oxides (NO_x), expressed in tenths of a ton, during a control period.

(2) Authorized account representative--The responsible person who is authorized, in writing, to transfer and otherwise manage allowances.

(3) Banked allowance--An allowance which is not used to reconcile emissions in the designated year of allocation, but which is carried forward for up to one year and noted in the compliance or broker account as "banked."

(4) Broker--A person not required to participate in the requirements of this division who opens an account under this division for the purpose of banking and trading allowances.

(5) Broker account--The account where allowances held by a broker are recorded. Allowances held in a broker account may not be used to satisfy compliance requirements for this division.

(6) Compliance account--The account where allowances held by a facility or multiple facilities at a single site are recorded for the purposes of meeting the requirements of this division.

(7) Control period--The 12-month period beginning January 1 and ending December 31 of each year. The initial control period begins January 1, 2002.

(8) Houston/Galveston (HGA) ozone nonattainment area--As defined in §101.1 of this title (relating to Definitions).

(9) Level of activity--The amount of activity at a source measured in terms of production, fuel use, raw materials input, or other similar units that have a direct correlation with the economic output and emission rate of the source (i.e., mass emitted per unit of activity).

(10) Person--For the purpose of issuance of allowances under this division, a person includes an individual, a partnership of two or more persons having a joint or common interest, a mutual or cooperative association, or a corporation.

(11) Site--As defined in §122.10 of this title (relating to General Definitions).

§101.351. Applicability.

This division applies to all stationary facilities which emit nitrogen oxides (NO_x) in the Houston/Galveston nonattainment area and are subject to the emission specifications under §§117.106, 117.206, and 117.475 of this title (relating to Emission Specifications for Attainment Demonstration; Emission Specifications for Attainment Demonstration; and Emission Specifications) and which have a design capacity to emit ten tons or more per year of NO_x.

§101.352. General Provisions.

(a) Allowances are valid only for the purposes described in this division and cannot be used to meet or exceed the limitations of any annual emission limitation authorized under Chapter 116, Subchapter B, of this title (relating to New Source Review Permits), or any other applicable rule or law.

(b) Beginning February 1, 2003, and no later than February 1 following the end of every control period, each site, shall hold a quantity of allowances in its compliance account that is equal to or greater than the total emissions of nitrogen oxides emitted during the control period just ending. Compliance with this division will begin with the initial control period beginning January 1, 2002.

(c) Unused allowances can be certified as emission reduction credits (ERCs), provided that:

(1) an enforceable and permanent reduction of annual allowances is approved by the executive director; and

(2) all applicable requirements of Division 1 of this subchapter (relating to Emission Credit Banking and Trading) are met.

(d) Allowances cannot be used for netting requirements under Chapter 116, Subchapter B, Divisions 5 and 6 of this title (relating to Nonattainment Review and Prevention of Significant Deterioration Review).

(e) Allowances may be used simultaneously to satisfy the correlating one to one portion of offset requirements for new or modified facilities subject to federal nonattainment NSR requirements as provided in Chapter 116, Subchapter B, Division 7 of this title (relating to Emission Reductions Offsets).

(f) An allowance does not constitute a security or a property right.

(g) All allowances will be allocated, transferred, or used in tenths of tons. To determine the number of allowances, the number of allowances will be rounded down to the nearest tenth when determining excess allowances and rounded up to the nearest tenth when determining allowances used.

(h) One compliance account shall be used for multiple facilities required to participate under this division and located at the same site and under common ownership or control.

(i) The commission will maintain a registry of the allowances in each compliance account. The registry will not contain proprietary information.

§101.353. Allocation of Allowances.

(a) Allowances will be deposited into compliance accounts according to the following equation except as provided in subsection (g) of this section.

Figure: 30 TAC §101.353(a)

(b) For a new and/or modified facility that has submitted, under Chapter 116 of this title, an application which the executive director has not determined to be administratively complete before January 2, 2001, or has qualified for a permit by rule under Chapter 106 of this title and has not commenced construction before January 2, 2001, allowances for each control period or the annual allocation rights shall be acquired from facilities already participating under this division, or in accordance with §101.356(d) of this title (relating to Allowance Banking and Trading).

(c) If actual emissions of NO_x during a control period exceed the amount of allowances held in a compliance account on February 1 following the control period, allowances for the next control period will be reduced by an amount equal to the emissions exceeding the allowances in the compliance account plus an additional 10%. This does not preclude additional enforcement action by the executive director.

(d) Allowances will be allocated by the executive director, who will deposit allowances into each compliance account:

(1) initially, by January 1, 2002;

(2) subsequently, by January 1 of each following year.

(e) The annual deposit for any control period may be adjusted by the executive director to reflect new or existing state implementation plan requirements.

(f) Allowances may be added or deducted by the executive director from compliance accounts following the review of reports required under §101.359 of this title (relating to Reporting).

(g) In extenuating circumstances, the executive director may deviate from the requirements of this section to determine the amount of allowances to be allocated to a facility. Applications to seek deviation must be submitted by the owner or operator of the facility in discussion to the executive director no later than June 30, 2001.

(h) Allowances calculated under subsection (a) of this section will continue to be based on historical activity levels, despite subsequent reductions in activity levels. If allowances are being allocated based on allowables and the facility does not achieve two complete consecutive calender years of actual level of activity data, then allowances will not continue to be allocated if the facility ceases operation or is not built.

§101.354. Allowance Deductions.

(a) Allowances will be deducted in tenths of a ton from a site's compliance account for a control period based upon the following equation or other method as determined by the executive director.
Figure: 30 TAC §101.354(a)

(b) When deducting allowances from a site's compliance account for a control period, the executive director will deduct the allowances beginning with the most recently allocated allowances before deducting banked allowances.

(c) Allowances allocated in accordance with the variables in (a)(2)(B) listed in Figure 30 TAC §101.353(a) may only be used by the facility for which they were allocated and may not be used by other facilities at the same site during the same control period.

(d) On February 1 after every control period, a site shall hold a quantity of allowances in its compliance account that is equal to or greater than the total NO_x emissions emitted during the prior control period.

§101.356. Allowance Banking and Trading.

(a) Allowances not used for compliance at the end of a control period may be banked for use in the following control period in compliance with §101.354 of this title (relating to Allowance Deductions) or traded except as provided in subsection (c) of this section.

(b) Allowances which have not expired or been used may be traded at any time during a control period after they have been allocated except as provided in subsection (c) of this section.

(c) Allowances not used for compliance during a control period which were allocated in accordance with the variables in (a)(2)(B) and (3)(B) listed in Figure 30 TAC §101.353(a) may not be banked for future use or traded.

(d) Only authorized account representatives may trade allowances.

(e) Trades shall be completed by the executive director following the submittal of a completed ECT-2 Form, Application for Transfer of Allowances. The completed ECT-2 shall include the price paid per allowance and shall be submitted to executive director at least 30 days prior to the allowances being deposited into the transferee's broker or compliance account. The executive director will issue a letter to the purchaser and seller reflecting this trade. The trade will be considered finalized upon issuance of this letter.

(f) Sites may use nitrogen oxides (NO_x) discrete emission reduction credits (DERCs) or mobile discrete emission reduction credits (MDERCs) which have been generated and, acquired, in accordance with Division 4 of this subchapter (relating to Discrete Emission Credit Banking and Trading) in place of allowances for compliance with this division in accordance with paragraphs (1)-(7) of this subsection. Sites may use volatile organic compound (VOC) DERCs or MDERCs which have been generated and acquired in accordance with Division 4 of this subchapter, in place of allowances for compliance with this division in accordance with paragraphs (1)-(7) of this subsection provided that demonstration has been made and approved by the executive director and the United States Environmental Protection Agency to show that the use of VOC DERCs or MDERCs is equivalent, on a one to one basis or other ratio, to the use of NO_x allowances in reducing ozone.

(1) MDERCs may be used in lieu of allowances at a ratio of one MDERC for one allowance.

(2) Prior to January 1, 2005, DERCs generated prior to January 1, 2005 may be used at a ratio of one DERC for one allowance.

(3) Beginning January 1, 2005, DERCs generated prior to January 1, 2005 may be used in lieu of allowances at a ratio of ten DERCs for one allowance.

(4) DERCs generated on or after January 1, 2005 may be used in lieu of allowances at a ratio of one DERC for one allowance.

(5) Beginning January 1, 2005, no more than 10,000 DERCs may be used in any combination totaled over all sites in the HGA ozone nonattainment area during a single calender year. This restriction does not apply to MDERCs.

(6) The 10% environmental contribution and the 5% compliance margin of Division 4 of this subchapter shall not apply.

(7) DERCs or MDERCs submitted with a notice of intent to use, DEC-2 Form, for the purpose of compliance with this section, must be submitted to executive director at least 30 days prior to intended use.

(g) Program Audits. No later than three years after the effective date of this division, and every three years thereafter, the executive director will audit this program.

(1) The audit will evaluate the impact of the program on the state's attainment demonstration, the availability and cost of allowances, compliance by the participants, and any other elements the executive director may choose to include.

(2) The executive director will recommend measures to remedy any problems identified in the audit. The trading of allowances, discrete emission reduction credits, and/or mobile discrete emission reduction credits may be discontinued by the executive director in part or in whole and in any manner, with commission approval, as a remedy for problems identified in the program audit.

(3) The audit data and results will be completed and submitted to the United States Environmental Protection Agency and made available for public inspection within six months after the audit begins.

§101.358. Emission Monitoring and Compliance Demonstration.

(a) Monitoring data or other emission quantifications for facilities required to monitor or quantify emissions under any other federal or state program shall be used to show compliance with this division.

(b) Facilities not required to monitor or quantify nitrogen oxides emissions shall calculate emissions using good engineering practices, including calculation methodologies in general use and accepted in new source review permitting.

§101.359. Reporting.

Beginning March 31, 2003, for each control period, facilities under each compliance account shall submit a completed ECT-1 Form, Annual Compliance Report, to the executive director by March 31 of each year detailing the following:

(1) the amount of actual nitrogen oxides (NO_x) emissions during the preceding control period;

(2) the method of determining NO_x emissions, including, but not limited to, any monitoring protocol and results, calculation methodology, level of activity, and emission factor; and

(3) a summary of all final trades for the preceding control period.

§101.360. Level of Activity Certification.

(a) The owner or operator of any facility subject to this division shall certify, no later than June 30, 2001, its historical level of activity by submitting to the executive director a completed ECT-3 Form, Level of Activity Certification, along with any supporting information such as usage records, testing or monitoring data, and production records as follows:

(1) for facilities in operation prior to January 1, 1997, the level of activity averaged over 1997, 1998, and 1999;

(2) for new and modified facilities not in operation prior to January 1, 1997 and either have submitted, under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification), an application which the executive director has determined to be administratively complete before January 2, 2001, or have qualified for a permit by rule under Chapter 106 of this title (relating to Permits by Rule) and have commenced construction before January 2, 2001, the level of activity authorized by the executive director.

(b) The owner or operator of any facility subject to this division who has certified a facility's level of activity under subsection (a)(2) of this section shall certify, no later than 90 days from the end of its second complete calendar year of operation, its first two complete consecutive calender years of actual level of activity by submitting to the executive director a completed ECT-3 Form, Level of Activity Certification, along with any supporting information such as usage records, testing or monitoring data, and production records.

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

Filed with the Office of the Secretary of State on December 29, 2000

TRD-200009073
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-6087

♦ ♦ ♦

DIVISION 4. DISCRETE EMISSION CREDIT BANKING AND TRADING

30 TAC §§101.370-101.374

STATUTORY AUTHORITY

The new sections are adopted under Texas Health and Safety Code, TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to develop a plan for control of the state's air; §382.017, which provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA, and United States Code, §7410(a)(2)(A), which requires SIPs to include enforceable emission limitations and other control measures or techniques, including economic incentives such as fees, marketable permits, and auction of emission rights.

§101.370. Definitions.

The following words and terms, when used in this division, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Activity--The amount of activity at a source measured in terms of production, use, raw materials input, vehicle miles traveled, or other similar units that have a direct correlation with the economic output and emission rate of the source (i.e., mass emitted per unit of activity).

(2) Actual emissions--Shall equal the total emissions during the selected time period, using the unit's actual daily operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(3) Applicable emission point--The emission point that is either generating an emission reduction or using a discrete emission credit.

(4) Area source--Any source included in the agency emissions inventory under the area source category.

(5) Baseline--Emissions that occur prior to an emission reduction strategy, considering all limitations required by applicable state and federal regulations. The baseline may not exceed the most recent level of emissions reported in the emissions inventory used for state implementation plan (SIP) determinations. For reduction strategies that exceed 12 months, the baseline is established after the first year of generation and is fixed for the life of the strategy. A new baseline is established for each emission reduction strategy.

(6) Baseline activity--The source's actual level of activity based on the unit's actual daily operating hours, production rates, or types of materials processed, stored, or combusted averaged over any consecutive two calendar year period including and following the most recent year of emissions inventory used for SIP determinations or subsequent year(s) which precede the emission reduction strategy or credit use period. For sources in existence less than two years, a shorter time period not less than 12 months may be considered by the executive director.

(7) Baseline emission rate--The source's rate of emissions per unit of activity during the baseline activity period.

(8) Baseline emissions--The source's total actual emissions based on the baseline activity and baseline emission rate.

(9) Certified--Any emission reduction that is determined to be creditable upon review and approval by the executive director.

(10) Curtailment--A temporary or partial reduction in activity level at any facility or mobile source.

(11) Discrete emission credit--An emission reduction generated over a discrete period of time, and measured in tons. A creditable emission credit such as a discrete emission reduction credit (DERC) or mobile discrete emission reduction credit (MDERC).

(12) Discrete emission reduction credit (DERC)--A creditable emission reduction which is created during a generation period, quantified after the period in which emissions reductions are made, and expressed in tons.

(13) Emission reduction--An actual reduction of emissions from a stationary or mobile source.

(14) Emission reduction strategy--The method implemented to reduce the source's emissions beyond that required by state or federal law, regulation, or agreed order.

(15) Generation period--The discrete period of time, not exceeding 12 months, over which a DERC is created.

(16) Generator--The owner or operator of a source that creates an emission reduction.

(17) Level of activity--The amount of activity at a source measured in terms of production, fuel use, raw materials input, or other similar units that have a direct correlation with the economic output and emission rate of the source (i.e., mass emitted per unit of activity).

(18) Mobile discrete emission reduction credit (MDERC or discrete mobile credit)--A credit that is surplus, generated by a mobile source strategy. It is a creditable emission reduction that is created during a generation period, quantified after the period in which emissions reductions are made, and expressed in tons.

(19) Mobile emissions baseline--Mobile emissions that occur prior to a mobile emission reduction strategy, considering all limitations required by applicable state and federal regulations. A valid mobile emission baseline can be calculated by either using measured emissions of an appropriately sized sample of the participating mobile sources using an approved United States Environmental Protection Agency (EPA) test procedure or by using estimated emissions of the participating mobile sources using the most recent edition of EPA's on-road or non-road mobile emissions factor models, or other model as applicable. To ensure that mobile credits are surplus, mobile source baseline emissions estimates for each year of the proposed mobile source control program must be the same as, or lower than, those used, or proposed to be used, in the SIP in which the control program is proposed.

(20) Mobile source--On-road (highway) vehicles (e.g., automobiles, trucks, and motorcycles) and non- road vehicles (e.g., trains, airplanes, agricultural equipments, industrial equipment, construction vehicles, off-road motorcycles, and marine vessels).

(21) Mobile source baseline activity--The mobile source's level of activity during the applicable mobile source baseline year.

(22) Mobile source baseline emissions--The mobile source's total emissions based on the product of mobile source baseline activity and mobile source baseline emission rate.

(23) Most stringent allowable emissions rate--The emissions rate of a source, considering all limitations required by applicable local, state, and federal regulations.

(24) Ozone season--The portion of the year when ozone monitoring is federally required to occur in a specific geographic area.

(25) Permanent--An emission reduction that is long-lasting and unchanging for the remaining life of the source.

(26) Protocol--A replicable and workable method of estimating emission rates or activity levels used to calculate the amount of emission reduction generated or credits required for stationary or mobile sources.

(27) Quantifiable--An emission reduction that can be measured or estimated with confidence using replicable techniques.

(28) Real reduction--A reduction in which actual emissions are reduced.

(29) Source--As defined in §101.1 of this title (relating to Definitions).

(30) Shutdown--The permanent cessation of an activity producing emissions at a facility.

(31) Strategy activity--The source's level of activity during the DERC generation period.

(32) Strategy emission rate--The source's level of activity during the DERC generation period.

(33) Surplus--An emission reduction that is not otherwise required of a source by a state or federal law, regulation, or agreed order.

(34) Use period--The period of time over which the user source applies discrete emission credits to an applicable emission reduction requirement.

(35) User--The owner or operator of a source that acquires and uses discrete emission credits to meet a regulatory requirement, demonstrate compliance, or offset an emission increase.

(36) Use strategy--The compliance requirement for which discrete emission credits are being used.

§101.372. General Provisions

(a) Applicable pollutants. Reductions of volatile organic compounds (VOCs), nitrogen oxides (NO_x), carbon (CO), sulfur dioxide (SO_2), and particulates with an aerodynamic diameter of less than or equal to a nominal ten microns (PM_{10}) may qualify as discrete emission credits as appropriate. Reductions of other criteria pollutants are not creditable. Reductions of one pollutant may not be used to meet the reduction requirements for another pollutant, except at such time as modeling demonstrates that one may be substituted for another or as approved by the executive director, and the United States Environmental Protection Agency (EPA).

(b) Discrete emission credit requirements.

(1) Discrete emission reduction credit (DERC)--To be creditable as a DERC, an emission reduction must be real, quantifiable, and surplus at the time the discrete emission credit is generated. The creditable reduction must have occurred after the most recent year of emissions inventory used for state implementation plan (SIP) determinations for all applicable pollutants and the source's annual emissions prior to the discrete emission credit application must have been reported or represented in the emissions inventory used for SIP determinations.

(2) Mobile discrete emission reduction credit (MDERC)--To be creditable as an MDERC, an emission reduction must be quantifiable, real, and surplus. The discrete emission credit must be surplus at the time it is created, as well as when it is used. The creditable reduction must have occurred after the most recent year of emissions inventory used for SIP determinations for all applicable pollutants, the mobile source's emissions must have been represented in the emissions inventory used for SIP determinations, and the mobile sources are in the attainment demonstration baseline. If a mobile reduction is implemented that is not in the baseline for emissions, this would not constitute an emission reduction.

(3) Emission reductions from a source which are certified as discrete emission credits under this division cannot be recertified in whole or in part as emission credits under another division within this subchapter.

(c) Eligible sources include the following:

(1) stationary sources (including area sources);

(2) mobile sources; or

(3) any stationary source (including area sources) or mobile source associated with actions by federal agencies under §101.30 of this title (relating to Conformity of General Federal Actions to State Implementation Plans).

(d) Life of a discrete emission credit. A discrete emission credit is available for use after the notice of generation, DC-1 Form, has been received and deemed creditable by the commission registry in accordance with subsection (h) of this section, and may be used anytime thereafter.

(e) Geographic scope. Emission reductions generated in the State of Texas may be creditable and used in the state with the following limitations.

(1) VOC and NO_x discrete emission credits generated in an ozone attainment area may be used in any county or portion of a county designated as attainment or unclassified, but may not be used in an ozone nonattainment area.

(2) VOC and NO_x discrete emission credits generated in an ozone nonattainment area may be used either in the same ozone nonattainment area in which they were generated, or in any county or portion of a county designated as attainment or unclassified.

(3) VOC and NO_x discrete emission credits generated in an ozone nonattainment area may not be used in any other ozone nonattainment area, except as provided in this subsection.

(4) CO, SO_2, and PM_{10} discrete emission credits must be used in the same metropolitan statistical area in which the reduction was generated.

(5) VOC and NO_x discrete emission credits generated in other counties, states, or nations can be used in any attainment or nonattainment county provided a demonstration has been made and approved by the executive director and the EPA to show that the emission reductions achieved in the other county, state, or nation improves the air quality in the county where the credit is being used.

(f) Trading discontinuation. The trading of discrete emission credits may be discontinued by the executive director in whole or in part and in any manner, with commission approval, as a remedy for problems resulting from trading in a localized area of concern.

(g) Ozone season. In areas having an ozone season of less than 12 months, VOC and NO_x discrete emission credits generated outside the ozone season may not be used during the ozone season.

(h) The registry. All required notices of discrete emission credit generators and users must be submitted to the registry. A notice submitted by a generator or user will be reviewed for credibility and when deemed certified, posted to the registry. The registry will assign a unique number to each ton of emission reductions generated. The registry will maintain current listings of all credits available or used for each ozone nonattainment area. One combined listing for all the counties or portions of counties designated as attainment or unclassified will be provided by the registry.

(i) Recordkeeping. The generator must maintain a copy of all notices and backup information submitted to the registry for a minimum of five years, following the completion of the generation period. The user must maintain a copy of all notices and backup information submitted to the registry for a minimum of five years, following the completion of the use period. Other relevant reference material or raw data must also be maintained on-site by the participating sources. The user must also maintain a copy of the generator's notice and backup information for a minimum of five years after the use is completed. The records shall include, but not necessarily be limited to:

(1) the name, emission point number (EPN), and facility identification number (FIN) of each unit using discrete emission credits;

(2) the amount of discrete emission credits being used by each unit;

(3) the specific number, name, or other identification of discrete emission credits used for each unit.

(j) Public information. All information submitted with a notice or report regarding the nature and quantity of emissions associated with the use or generation of discrete emission credits is public information and may not be submitted as confidential. Any claim of confidentiality for this type of material or failure to submit all information may result in the rejection of the emission reduction. All non-confidential notices and information regarding the generation, use, and availability of discrete emission credits may be obtained from the registry.

(k) Authorization to emit. A discrete emission credit created under this division is a limited authorization to emit the specified pollutants in accordance with the provisions of this section, the Federal Clean Air Act, and the Texas Clean Air Act, as well as regulations promulgated thereunder. A discrete emission credit does not constitute a property right. Nothing in this division should be construed to limit the authority of the commission or the United States Environmental Protection Agency to terminate or limit such authorization.

(l) Program participation. The executive director has the authority to prohibit a company from participating in discrete emission credit trading either as a generator or user, if the executive director determines that the company has violated the requirements of the program or abused the privileges provided by the program.

§101.373. Protocols.

(a) All discrete emission credit source categories must use an United States Environmental Protection Agency (EPA) approved protocol if one exists for the applicable source. If the source wants to deviate from an EPA approved protocol, EPA approval is required before the protocol can be used.

(b) If an EPA approved protocol does not exist, the amount of discrete emission credits in tons will be determined and certified based on actual monitoring results, when available, or otherwise calculated using good engineering practices, including calculation methodologies in general use in new source review (NSR) permitting. The source must collect relevant data sufficient to characterize the process emissions of the affected pollutant and the process activity level for all representative phases of source operation during the period under which discrete emission credits are created or used.

(c) Discrete emission credit generation.

(1) Discrete emission reduction credits (DERCs) may be generated by any strategy that reduces a source's emission rate below its baseline and is approved by the executive director, except for the following:

(A) temporary curtailment of an activity at a source;

(B) modification or discontinuation of any activity that is otherwise in violation of a federal, state, or local law;

(C) emissions reductions required to comply with any provision under Title I of the Federal Clean Air Act (FCAA) regarding tropospheric ozone, or Title IV of the FCAA regarding acid rain;

(D) emission reductions of hazardous air pollutants, as defined in the FCAA, §112, from application of a standard promulgated under FCAA, §112;

(E) emission reductions which have occurred as a result of transferring the emissions to another source;

(F) emission reductions credited or used under any other emissions trading program;

(G) emission reductions occurring at a source which received an alternative emission limitation to meet a state reasonably available control technology requirement, except to the extent that the emissions are reduced below the level that would have been required had the alternative emission limitation not been issued; and

(H) emission reductions at a facility with a flexible permit, unless the reductions are made permanent and enforceable or the generator can demonstrate that the emission reductions were not used to satisfy the conditions for the facilities under the flexible permit.

(2) A mobile discrete emission reduction credit (MDERC) may be generated by any mobile source emission reduction strategy that creates actual mobile source emission reductions under this rule, and is subject to the approval of the commission.

(d) Discrete emission credits generation calculation.

(1) DERCs, except for shutdowns, are calculated as follows.
Figure: 30 TAC §101.373(d)(1)

(A) The amount of DERCs generated must be rounded down to the nearest ton.

(B) For shutdown emission reduction strategies, the quantity of emission reduction generated is equivalent to the baseline emissions.

(C) The generation period for a shutdown is five years. Shutdown DERCs must be generated and noticed to the registry on an annual basis.

(D) If a source's emissions exceed its allowable emission limit, the amount of emissions exceeding the limit may not be certified as DERCs.

(2) An MDERC may be calculated from the annual difference between the mobile source emissions baseline and the actual emissions level after the MDERC strategy has been put in place. The MDERC must be based on actual in-use emissions of the replacement or substitute mobile source. Emission baselines for quantifying MDERCs should include the following information and data as appropriate, but not be limited to:

(A) the emission standard to which the mobile source is subject or emission performance to which the mobile source is certified;

(B) the measured in-use emissions levels per unit of use from all significant mobile source emissions sources;

(C) the number of mobile sources in the participating group;

(D) the type or types of mobile sources by model year; and

(E) the actual activity level, hours of operation or miles traveled by type, and model year.

(e) Registration and certification.

(1) A notice of generation and generator certification (DEC-1 Form), must be submitted to the executive director no later than 90 days after the discrete emission reduction strategy activity has been completed, or no later than 90 days after the completion of the first 12 months of generation, if the generation period exceeds 12 months, whichever is sooner. Submission of the DEC-1 Form should continue every 12 months thereafter for each subsequent year of generation.

(2) In the notice for a stationary source, including area source, the generator must include the following information for each pollutant reduced at each applicable emission point:

(A) the name, address, county, telephone number, contact person, permit or standard exemption numbers, account number of the generator, and the unique facility identification number (FIN) and emission point number (EPN) of the applicable emission points;

(B) the name of the owner and/or operator of the generator source;

(C) the generation period;

(D) a complete description of the generation activity;

(E) for shutdown emission reduction strategies, an explanation as to whether production shifted from the shut down facility to another facility in the same nonattainment area;

(F) the amount of emission credits generated;

(G) for volatile organic compound (VOC) reductions, a list of the specific compounds reduced;

(H) the baseline emission activity, baseline emission rate, emission reduction strategy emission rate, emission reduction strategy activity, emissions inventory data from the most recent year of emissions inventory used for state implementation plan determinations and emissions inventory data for the two consecutive years used to determine the baseline activity for each applicable pollutant and emission point;

(I) the most stringent emission rate for the applicable emission point, considering all the local, state, and federal applicable regulatory requirements;

(J) a complete description of the protocol used to calculate the emission reduction generated;

(K) the actual calculations performed by the generator to determine the amount of discrete emission credits generated; and

(L) a statement that the emission reductions on which the emission credits DERCs are based are real, surplus, and not based on an emission reduction strategy that is prohibited.

(3) The notice for a mobile source generator must include the following information to verify the credit calculation, but is not limited to:

(A) the name, address, county, telephone number, and contact person;

(B) the name of the owner and/or operator of the generator source;

(C) the date of the reduction;

(D) a complete description of the generation activity;

(E) the amount of discrete mobile source emission credits generated;

(F) the mobile source baseline emission activity, mobile source baseline emission rate, mobile source baseline total emissions, and the mobile source strategy;

(G) a complete description of the protocol used to calculate the discrete mobile source emission reduction generated;

(H) the actual calculations performed by the generator to determine the amount of discrete mobile source emission credits generated; and

(I) a statement that the discrete mobile source emission reductions on which the MDERCs are based are real, surplus, and not based on a mobile source emission reduction strategy that is prohibited.

(4) Registrations will be reviewed in order to determine the credibility of the reductions. Reductions determined to be creditable will be certified by the executive director.

(5) The applicant will be notified in writing if the executive director denies the notification. The applicant may submit a revised notification at any time.

(f) Discrete emission credit practices.

(1) The amount of DERCs, in tons, will be determined and certified based on actual monitoring results, when available, or otherwise calculated using good engineering practices, including calculation methodologies in general use in NSR permitting. The source must collect relevant data sufficient to characterize the process emissions of the affected pollutant and the process activity level for all representative phases of source operation during the period under which DERCs are created or used.

(2) The amount of MDERCs will be quantified in tons. MDERCs will be determined and certified based on: EPA methodologies, when available; actual monitoring results, when available; otherwise calculated using the most current EPA MOBILE model; or otherwise calculated using creditable emission reduction measurement or estimation methodologies which satisfactorily address the analytical uncertainties of mobile source emissions reduction strategies. The generator must collect relevant data sufficient to characterize the process emissions of the affected pollutant and the process activity level for all representative phases of source operation during the period under which the MDERCs are created or used.

(3) All discrete emission credits are deposited in the registry and reported as available credits until they are used, withdrawn, or expire.

(4) Compliance burden and enforcement.

(A) The generator is responsible for assuring that the discrete emission credits generated are certified.

(B) The user is responsible for ensuring that discrete emission credits which currently reside in the registry and are not certified are certified prior to use.

(5) Discrete emission credits may be used if the following requirements are met.

(A) The user must have ownership of a sufficient amount of discrete emission credits before the use period for which the specific discrete emission credits are to be used.

(B) The user must hold sufficient discrete emission credits to cover the user's compliance obligation at all times.

(C) The user shall acquire additional discrete emission credits during the use period if the user determines that he does not possess enough discrete emission credits to cover the entire use period. The user must acquire additional credits as allowed under this section prior to the shortfall, or the user will be in violation of this section.

(D) Source operators may acquire and use only discrete emission credits listed on the registry.

(6) With the exception of uses prohibited in paragraph (7) of this subsection or strictly prohibited in other rules or regulations, discrete emission credits may be used to meet or demonstrate compliance with any mobile or stationary regulatory requirement including the following:

(A) to exceed any allowable emission level, if the following conditions are met:

(i) in ozone nonattainment areas, permitted facilities may use discrete emission credits to exceed permit allowables by no more than 25 tons for nitrogen oxides (NO_x) or five tons for VOC in a 12-month period as approved by the executive director. This use is limited to one exceedance up to 12 months, within any 24-month period per use strategy. The use must extend beyond a 24-hour period; or

(ii) at permitted facilities in counties or portions of counties designated as attainment or unclassified, discrete emission credits may be used to exceed permit allowables by values not to exceed the prevention of significant deterioration significance levels as provided in 40 Code of Federal Regulations, §52.21(b)(23), as approved by the executive director prior to use. This use is limited to one exceedance up to 12 months, within any 24-month period per use strategy. The user must demonstrate that there will be no adverse impacts from the use of discrete emission credits at the levels requested;

(B) as NSR offsets if the following requirements are met:

(i) the user must obtain the executive director's approval prior to the use of specific discrete emission credits to cover, at a minimum, one year of operation of the new or modified source in the NSR permit;

(ii) the NSR permit must contain an enforceable requirement that the source obtain at least one additional year of offsets before continuing operation in each subsequent year;

(C) compliance with NO_x cap and trade requirements as provided in §101.356(d)of this title (relating to Allowance Banking and Trading).

(D) compliance with §115.950 of this title (relating to Emissions Trading) and §117.570 of this title (relating to Use of Emission Credits for Compliance), as allowed.

(7) A discrete emission credit, under this division, may not be used:

(A) before it has been acquired by the user;

(B) for netting to avoid the applicability of federal and state NSR requirements;

(C) to meet FCAA requirements for:

(i) new source performance standards under FCAA, §111;

(ii) lowest achievable emission rate standards under FCAA, §173(a)(2);

(iii) best available control technology standards under FCAA, §165(a)(4);

(iv) hazardous air pollutants standards under FCAA, §112, including the requirements for maximum achievable control technology;

(v) standards for solid waste combustion under FCAA, §129;

(vi) requirements for a vehicle inspection and maintenance program under FCAA, §182(b)(4) or (c)(3);

(vii) ozone control standards set under FCAA, §183(e) and (f);

(viii) clean-fueled vehicle requirements under FCAA, §246;

(ix) motor vehicle emissions standards under FCAA, §202;

(x) standards for nonroad vehicles under FCAA, §213;

(xi) requirements for reformulated gasoline under FCAA, §211(k); or

(xii) requirements for Reid vapor pressure standards under FCAA, §211(h) and (i).

(D) to allow an emissions increase of an air contaminant that exceeds the limitations of §106.261(3) or (4) or §106.262(3) of this title (relating to Facilities (Emission Limitations) and Facilities (Emission and Distance Limitations)) except as approved by the executive director;

(E) to authorize a source whose emissions are enforceably limited to below applicable major source threshold levels, as defined in §122.10 of this title (relating to General Definitions), to operate with actual emissions above those levels without triggering applicable requirements that would otherwise be triggered by such major source status;

(F) to exceed an allowable emission level where the exceedance would cause or contribute to a condition of air pollution as determined by the executive director.

(8) Calculation of discrete emission credits.

(A) A user may use the following equation to calculate the amount of discrete emission credits necessary to comply with §117.223 of this title (relating to Source Cap) instead of the equations in §117.223(b)(1) and (2) of this title.
Figure: 30 TAC §101.373(f)(8)(A)

(B) Otherwise, the amount of discrete emission credits needed to demonstrate compliance or meet a regulatory requirement is calculated as follows.
Figure: 30 TAC §101.373(f)(8)(B)

(C) The amount of discrete emission credits needed must be rounded up to the nearest ton.

(D) The user must possess 10% more discrete emission credits than are needed, as calculated in subparagraph (B) of this paragraph, to ensure that the source's environmental contribution retirement obligation will be met.

(E) If the amount of discrete emission credits needed to meet a regulatory requirement or to demonstrate compliance is greater than ten tons, an additional 5.0% of the discrete emission credits needed, as calculated in subparagraph (B) of this paragraph, must be acquired to ensure that sufficient discrete emission credits are available to the user with an adequate compliance margin.

(F) The amount of discrete emission credits needed for NSR offsets equals the quantity of tons needed to achieve the maximum allowable emission level set in the user's NSR permit. The user must also purchase and retire enough discrete emission credits to meet the offset ratio requirement in the user's ozone nonattainment area. The user must purchase and retire either the environmental contribution of 10% or the offset ratio, whichever is higher.

(G) Discrete emission credits that are not used during the use period are surplus and remain available for transfer or use by the holder. In addition, any portion of the calculated environmental contribution not attributed to actual use is also available.

(g) Notice of intent to use. A notice of intent to use, DEC-2 Form, must be submitted to the executive director in accordance with the following requirements:

(1) discrete emission credits may be used only after the user has submitted the notice to the registry;

(2) the notice must be submitted at least 45 days prior to the first day of the use period if the generator is a stationary source, and 90 days if the generator is a mobile source, and every 12 months thereafter for each subsequent year if the use period exceeds 12 months;

(3) a copy of the notice must also be sent to the federal land manager 30 days prior to use if the user is located within 100 kilometers of a Class I area;

(4) the notice for a stationary or area source user must include the following information for each use:

(A) the name, address, county, telephone number, contact person, permit or standard exemption numbers, and account number of the user, and the unique FIN and EPN identification numbers for each emission point;

(B) the name of the owner and/or operator of the user source;

(C) the applicable state and federal requirements that the discrete emission credits will be used to comply with and the intended use period;

(D) the amount of discrete emission credits needed;

(E) the baseline emission rate, activity level, and total emissions for the applicable emission points;

(F) the actual emission rate, activity level, and total emissions for the applicable emission points;

(G) the most stringent emission rate and the most stringent emission level for the applicable emission points, considering all applicable regulatory requirements;

(H) a complete description of the protocol used to calculate the amount of discrete emission credits needed;

(I) the actual calculations performed by the user to determine the amount discrete emission credits needed;

(J) the date on which the discrete emission credits were acquired or will be acquired;

(K) the discrete emission credit generator and the serial numbers of the discrete emission credits acquired or to be acquired;

(L) the price of the discrete emission credits acquired or the expected price of the discrete emission credits to be acquired; and

(M) a statement that due diligence was taken to verify that the discrete emission credits were not previously used, that the discrete emission credits were not generated as a result of actions prohibited under this regulation, and that the discrete emission credits will not be used in a manner prohibited under this regulation.

(5) the notice for a mobile source user must include the following information:

(A) the name, address, county, telephone number, and contact person;

(B) the name of the owner and/or operator of the user source;

(C) the applicable state and federal requirements that the discrete emission credits will be used to comply with and the intended use period;

(D) the amount of discrete emission credits needed;

(E) the mobile source baseline emission rate, mobile source activity level, and total mobile source emissions for the applicable mobile sources;

(F) the actual mobile source emission rate, activity level, and total emissions for the applicable mobile source;

(G) the most stringent mobile source emission rate and the most stringent mobile source emission level for the applicable emission points, considering all applicable regulatory requirements;

(H) a complete description of the protocol used to calculate the amount of MDERCs needed;

(I) the actual calculations performed by the user to determine the amount MDERCs needed;

(J) the date on which the MDERCs were acquired or will be acquired;

(K) the MDERC generator and the serial numbers of the MDERCs acquired or to be acquired;

(L) the price of the MDERCs acquired or the expected price of the MDERCs to be acquired;

(M) a statement that due diligence was taken to verify that the MDERCs DERCs were not previously used, that the MDERCs were not generated as a result of actions prohibited under this regulation, and that the MDERCs will not be used in a manner prohibited under this regulation; and

(N) a certification of use, which must contain certification under penalty of law by a responsible official of the user source of truth, accuracy, and completeness. This certification must state that based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete;

(6) a user may submit a notice late in the case of an emergency, but the notice must be submitted before the discrete emission credits can be used. The user must include a complete description of the emergency situation in the notice of intent to use. All other notices submitted less than 45 days prior, or 90 days prior for a mobile source, to use will be considered late and in violation;

(7) the user is responsible for determining the credits it will purchase and notifying the executive director of the selected generating source in the notice of intent to use. If the generator's credits are rejected or the notice of generation is incomplete, the use of discrete emission credits by the user may be delayed by the executive director. The user cannot use any discrete emission credits that have not been certified by the executive director. The executive director may reject the use of discrete emission credits by a source if the credit and use cannot be demonstrated to meet the requirements of this section.

(A) Actual discrete emission credits use.

(i) The user shall calculate:

(I) the amount of discrete emission credits used, including the amount of discrete emission credits retired to cover the environmental contribution associated with actual use; and

(II) the amount of discrete emission credits not used, including the amount of excess discrete emission credits that were purchased to cover the environmental contribution but not associated with the actual use, and available for future use.

(ii) A report of use, DEC-3 Form, must be submitted to the registry in accordance with the following requirements:

(I) a report of use must be submitted within 90 days after the end of the use period;

(II) the report must be submitted within 90 days of the conclusion of each 12-month use period, if applicable;

(III) the report is to be used as the mechanism to update or amend the notice of intent to use and must include any information different from that reported in the notice of intent to use, including, but not limited to, the following items:

(-a-) purchase price of the discrete emission credits obtained prior to the current use period;

(-b-) the actual amount of discrete emission credits possessed during the use period;

(-c-) the actual emissions during the use period for VOC and NO_x;

(-d-) the actual amount of discrete emission credits used;

(-e-) the actual environmental contribution; and

(-f-) the amount of discrete emission credits available for future use.

(iii) The user is in violation of this section if the user submits the report of use later than the allowed 90 days following the conclusion of the use period.

(iv) The registry shall not contain proprietary information.

(B) Compliance burden and enforcement.

(i) The user is responsible for assuring that a sufficient quantity of discrete emission credits is acquired to cover the applicable source's emissions for the entire use period. The user should ensure that the credits are real, surplus, and properly quantified discrete emission credits for purchase.

(ii) The user is in violation of this section if the user does not possess enough discrete emission credits to cover the credit need for the use period. If the user possesses an insufficient quantity of discrete emission credits to cover its compliance need, the user will be out of compliance for the entire use period, unless the user can demonstrate otherwise. Each day the user is out of compliance may be considered a violation.

(iii) Users may not transfer their compliance burden and legal responsibilities to a third party participant. Third party participants may only act in an advisory capacity to the user.

(C) Discrete emission credits are freely transferable in whole or in part, and may be traded or sold to a new owner anytime before the expiration date of the discrete emission credit. The Emissions Banking and Trading Program must be notified by means of an DC-4 Form prior to the transfer. The executive director will issue a letter to the discrete emission credit purchaser reflecting the discrete emission credits purchased by the new owner, and a letter to the discrete emission credit seller showing any remaining discrete emission credits available to the original owner. Discrete emission credits may be transferrable only after the executive director grants approval of the transaction.

§101.374. Program Audits.

(a) No later than three years after the effective date of this division section, and every three years thereafter, the executive director will audit this program.

(b) The audit will evaluate the timing of credit generation and use, the impact of the program on the state's attainment demonstration and the emissions of hazardous air pollutants, the availability and cost of credits, compliance by the participants, and any other elements the executive director may choose to include.

(c) The executive director will recommend measures to remedy any problems identified in the audit. The trading of discrete emission credits may be discontinued by the executive director in part or in whole and in any manner, with commission approval, as a remedy for problems identified in the program audit.

(d) The audit data and results will be completed and submitted to the United States Environmental Protection Agency and made available for public inspection within six months after the audit begins.

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

Filed with the Office of the Secretary of State on December 29, 2000

TRD-200009074
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-6087

♦ ♦ ♦

CHAPTER 114. CONTROL OF AIR POLLUTION FROM MOTOR VEHICLES

The Texas Natural Resource Conservation Commission (commission) adopts amendments to §114.6, Low Emission Fuel Definitions; §114.312, Low Emission Diesel Standards; §114.313, Designated Alternate Limits; §114.314, Registration of Diesel Producers and Importers; §114.315, Approved Test Methods; §114.316, Monitoring, Recordkeeping, and Reporting Requirements; §114.317, Exemptions to Low Emission Diesel Requirements; and §114.319, Affected Counties and Compliance Dates. The commission adopts these amendments to Chapter 114, Control of Air Pollution From Motor Vehicles, and corresponding revisions to the state implementation plan (SIP) in order to control ground-level ozone in the Houston/Galveston (HGA), Dallas/Fort Worth (DFW), and Beaumont/Port Arthur (BPA) ozone nonattainment areas. Sections 114.6, 114.312, 114.313, 114.315, 114.316, 114.317, and 114.319 are adopted *with changes* to the proposed text as published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8169). Section 114.314 is adopted *without changes* to the proposed text and will not be republished.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

The HGA ozone nonattainment area is classified as Severe-17 under the Federal Clean Air Act (FCAA) Amendments of 1990 (42 United States Code (USC), §§7401 et seq.), and therefore is required to attain the one-hour ozone standard of 0.12 parts per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined by Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties, has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of its Post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base-case episodes, proposed rules to achieve a 9% rate-of-progress (ROP) reduction in volatile organic compounds (VOC), and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary nitrogen oxide (NO_x) waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base-case episodes which marginally exhibited model performance in accordance with the United States Environmental Protection Agency (EPA) modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data-gathering exercise known as the COAST study. The state believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, the EPA policy regarding SIP elements and timelines went through changes. Two national programs in particular resulted in changing deadlines and requirements. The first of these programs was the Ozone Transport Assessment Group (OTAG). This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in this study, and it has been concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that has impacted the SIP planning process is the revisions to the national ambient air quality standard (NAAQS) for ozone. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, the EPA proposed an interim implementation plan (IIP) that it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development timelines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, that standard would continue to apply until it is attained. The FCAA requires that HGA attain the standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998 a revision to the HGA SIP which contained the following elements in response to the EPA guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by Subpart 2 of Title I of the FCAA to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the state eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs as well as an acceleration simulation mode equivalent motor vehicle inspection and maintenance program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory state-wide programs proposed or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon Scenario VIf); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review; and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-99 ROP plan by December 31, 2000; to perform a mid-course review by May 1, 2004; and to perform modeling of mobile source emissions using the EPA mobile source emissions model (MOBILE6), to revise the on-road mobile source budget as needed, and to submit the revised budget within 24 months of the model's release. In addition, if a conformity analysis is to be performed between 12 months and 24 months after the MOBILE6 release, the state will revise the motor vehicle emissions budget (MVEB) so that the conformity analysis and the SIP MVEB are calculated on the same basis.

In order for the state to have an approvable attainment demonstration, the EPA indicated that the state must adopt those strategies modeled in the November submittal and then adopt sufficient controls to close the remaining gap in NO_x emissions. The modeling and other analysis supporting these rules and the HGA SIP indicate a gap of approximately an additional 91 tons per day (tpd) of NO_x reductions is necessary for an approvable attainment demonstration. The predicted emission reductions is necessary to successfully demonstrate attainment.

The emission reduction requirements included as part of this SIP revision represent substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, have worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area have formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

This rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register,* or were included in the HGA SIP considered by the commission on December 6, 2000 and planned to be submitted to EPA by December 31, 2000.

The amount of NO_x reductions required for the area to attain the ozone NAAQS has 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 reduction strategies. The FCAA, 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 oversight committee. Commission staff have continued to improve the air quality modeling technology and refine emission inventory data. Numerous emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources, on-road and non-road mobile sources, and area sources were analyzed in multiple iterations of modeling, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling and other analysis submitted for public hearing and comment concurrently with the HGA SIP show that a significant amount of NO_x reductions practicably achievable are necessary from ozone control strategies in order for the HGA nonattainment area to achieve the ozone NAAQS by 2007, including reductions from surrounding counties included in the HGA consolidated metropolitan statistical area (CMSA).

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies. At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The current SIP revision contains rules, enforceable commitments, photochemical modeling analyses, and calculation of the remaining NO_x reductions required to reach attainment (gap calculation) in support of the HGA ozone attainment demonstration. In addition, this SIP contains Post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contains enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit a mid-course review.

The HGA ozone nonattainment area will need to ultimately reduce NO_x more than 750 tpd to reach attainment with the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of the low emission diesel fuel (LED) program will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area. The extension of these rules to all counties in the state should also contribute to maintenance of the one-hour standard in the rest of the state. A LED program also should contribute to a successful demonstration of transportation conformity in the HGA area and other nonattainment areas.

These rules are one element of the control strategy for the HGA Attainment Demonstration SIP. The purpose of these rules is to establish a LED air pollution control strategy that reduces NO_x emissions necessary for the HGA nonattainment area to be able to demonstrate attainment with the ozone NAAQS. Additional benefits will be achieved in the BPA, El Paso, and DFW ozone nonattainment areas, the 95-county central and eastern Texas region, as well as the remainder of the state.

The adopted revisions to the LED rules will require LED fuel statewide for on-road use. In addition, the revisions to the LED rules will require LED fuel for both on-road and non-road use in the eight counties in the HGA ozone nonattainment area which includes Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties; the four counties of the DFW ozone nonattainment area which includes Collin, Dallas, Denton, and Tarrant Counties; the three counties of the BPA ozone nonattainment area which includes Hardin, Jefferson, and Orange Counties; and 95 additional central and eastern Texas counties including Anderson, Angelina, Aransas, Atascosa, Austin, Bastrop, Bee, Bell, Bexar, Bosque, Bowie, Brazos, Burleson, Caldwell, Calhoun, Camp, Cass, Cherokee, Colorado, Comal, Cooke, Coryell, De Witt, Delta, Ellis, Falls, Fannin, Fayette, Franklin, Freestone, Goliad, Gonzales, Grayson, Gregg, Grimes, Guadalupe, Harrison, Hays, Henderson, Hill, Hood, Hopkins, Houston, Hunt, Jackson, Jasper, Johnson, Karnes, Kaufman, Lamar, Lavaca, Lee, Leon, Limestone, Live Oak, Madison, Marion, Matagorda, McLennan, Milam, Morris, Nacogdoches, Navarro, Newton, Nueces, Panola, Parker, Polk, Rains, Red River, Refugio, Robertson, Rockwall, Rusk, Sabine, San Jacinto, San Patricio, San Augustine, Shelby, Smith, Somervell, Titus, Travis, Trinity, Tyler, Upshur, Van Zandt, Victoria, Walker, Washington, Wharton, Williamson, Wilson, Wise, and Wood Counties.

The commission's current understanding, based upon national studies as well as the commission's own studies, is that ozone must be controlled at two levels: the regional level and the urban level. Historically, the FCAA has states focusing on the ozone problem at the local level. Recently, however, this has begun to change. The EPA has started to incorporate the findings of the OTAG, the Southern Oxidant Study, and the advice of stakeholders (e.g., the Federal Advisory Committee Act Subcommittee on Ozone, Particulate Matter, and Regional Haze Implementation) into recent policy guidance, encouraging states to factor regional reductions into their control plans.

On a national level, the OTAG study and its findings are particularly noteworthy. OTAG was established by the EPA to work with states in the eastern portion of the country to develop strategies to address the regional ozone problem. Among the OTAG determinations were that ozone is pervasive; ozone and the compounds that form it are transported both at lower levels of the atmosphere and aloft from one day to the next; and ozone precursors reductions over a large area are beneficial in the lowering of regional ozone background levels.

The commission's own studies provided evidence that there is regional transport of ozone and ozone precursors in Texas, and that regional reductions of ozone precursors are beneficial. The commission's own modeling studies have shown that pollutant sources across Texas contribute to regional ozone background levels, and that regional ozone precursor reductions will lower those background levels. These studies and upper air monitoring have found that regional air pollution should be considered when studying air quality in the Texas ozone nonattainment areas. This work is supported by the OTAG study which is the most comprehensive attempt ever undertaken to understand and quantify the transport of ozone. Both the commission and OTAG study results point to the need to take a regional approach to control air pollutants, such as that described in the regional control strategy adopted by the commission.

Reducing regional background ozone levels through a regional strategy will serve three purposes. It will give existing nonattainment areas the flexibility to design optimal local control strategies to help them attain the one-hour and eight-hour ozone standards. It will help areas, which are currently close to violating the standards, to avoid actually violating. Finally, over the longer term, it will help prevent the developing areas of the state from ever violating the standards.

The regional aspect of the state LED fuel program was developed to provide LED fuel for use in areas of the state that could potentially have a negative air quality impact on current ozone nonattainment areas, near nonattainment areas, and future areas of concern. For example, the HGA ozone nonattainment area currently needs every possible emission reduction to demonstrate attainment; the BPA nonattainment area attainment goals are heavily influenced by transport from HGA; the DFW ozone nonattainment area is also impacted by transport and has little leeway to handle additional emissions based on their current attainment demonstration modeling; and several near-nonattainment areas for the new eight-hour standard are seeking immediate reductions to preclude a nonattainment area designation. All of these areas will benefit from the reductions attributed to the regional aspect of the state-wide LED fuel program.

The main attractiveness of the fuel-based strategy is that it has a more immediate impact than other controls. Once the fuel is in the marketplace, it begins having an immediate air quality impact as both old and new vehicles and non-road equipment begin using the new fuel.

A state-wide LED fuel requirement facilitates distribution. The state-wide coverage area for on-road use will create a large enough market to ease the costs of distribution. Supplies can be co-mingled in the pipeline, trading can take place, and tracking compliance will be simplified. Because a federal reformulated gasoline is already distributed to the DFW and HGA ozone nonattainment areas, and the state's low-Reid vapor pressure (RVP) gasoline is already distributed to the 95-county central and eastern Texas regional area, diesel producers and importers will be able to use the current distribution system to distribute state LED fuel to the affected areas beginning in 2006 when the sulfur content in LED is limited to 15 ppm for the HGA, BPA, and DFW ozone nonattainment areas and the 95-county central and eastern Texas region.

A state-wide LED fuel requirement also reduces non-compliant fuel usage within the nonattainment areas due to out-of-area refueling by pass-through truck traffic. According to data shown on a 1997 truck traffic flow map published by the Texas Department of Transportation (TxDOT), over 10,000 trucks per day traverse the HGA nonattainment area. In addition, according to a TxDOT report, *Effect of the North American Free Trade Agreement on the Texas Highway System,* December 1998, the volume of truck traffic through the HGA nonattainment area directly associated with the North American Free Trade Agreement ranges between 1,001 and 2,500 trucks per day. Therefore, state-wide coverage for on-road LED use will ensure that higher volumes of pass-through truck traffic will be refueling with LED within the state, and will be using this fuel when traveling within the state's nonattainment areas.

The LED fuel will lower the emissions of NO_x and other pollutants from fuel combustion. Because NO_x is a precursor to ground-level ozone formation, reduced emissions of NO_x will result in ground-level ozone reductions. To comply with the state LED regulations, diesel fuel producers and importers must ensure that diesel fuel distributed to the LED fuel zone meets the specifications stated in these adopted rules. These rules require that, beginning May 1, 2002, diesel fuel produced for delivery and ultimate sale to the consumer in the affected area shall not exceed 500 ppm sulfur, must contain less than 10% by volume of aromatic hydrocarbons, and must have a cetane number of 48 or greater. In addition, these rules will require the sulfur content in the diesel fuel supplied to the DFW, BPA, and HGA ozone nonattainment areas and 95 central and eastern Texas counties, be reduced to 15 ppm sulfur beginning June 1, 2006. Also, these rules require diesel fuel producers and importers who provide fuel to the affected areas to register with the commission and provide quarterly status reports.

These rules will also revise definitions that will impact who is affected by the adopted state LED fuel program as well as who is impacted by the current requirements of the regional low-RVP gasoline program, specified in §§114.301, 114.304 - 114.307, and 114.309. These rules will restrict the registration, reporting, and testing requirements of these programs to those persons who have direct control over changes in fuel content, i.e., those persons who produce fuel or import fuel into the state.

The commission is aware that the EPA is currently proposing revised nationwide diesel fuel sulfur controls. If a new federal diesel fuel sulfur rule is adopted that covers the areas in Texas impacted by this rule, and the federal rule is at least as stringent as these rules, then the commission may consider compliance with the national rule equally effective and may repeal the state sulfur requirements for diesel fuel.

The commission is expanding the LED fuel ozone control strategy which was developed for the DFW area and requiring diesel fuel content limits more restrictive than federal diesel fuel regulations. The current federal regulations governing diesel fuel quality in Title 40 Code of Federal Regulations (40 CFR) Part 80, Regulation of Fuels and Fuel Additives, §80.29, Controls and Prohibitions on Diesel Fuel Quality, establish limits for fuel content for diesel fuel used in on-road motor vehicle applications. These federal regulations limit sulfur in on-road diesel fuel to 500 ppm and allow the producer to choose between meeting a minimum cetane number of 40 or a maximum aromatic hydrocarbon content of 35% by volume. The state's LED regulations limit on-road diesel to 500 ppm sulfur, 10% aromatic hydrocarbons, and a 48 cetane minimum, and with a more restrictive limit on sulfur being implemented on-road and non-road in the HGA, DFW, BPA ozone nonattainment areas and 95 central and eastern Texas counties in June 2006. As such, the commission is submitting, as part of the SIP, concurrent with this rulemaking, a request for a waiver in accordance with the 42 USC, §7545(C)(4)(c), for the on-road portion of these rules. Although the EPA regulates diesel fuel content for on-road use, it does not regulate the fuel content for non-road diesel fuel. Therefore, because there is currently no federal limit on the content of non-road diesel, the state has independent authority to place controls on the composition of non-road diesel fuel and the commission does not believe that a waiver is needed for the non-road portion of these rules. This adopted SIP submittal is available to the public by contacting Heather Evans at (512) 239-1970.

Modeling performed for the commission assessing the benefits of this NO_x emission reduction strategy demonstrated that significant emission reductions could be achieved by using a low aromatic hydrocarbon/high cetane diesel fuel as specified by the commission's LED fuel requirements. By the year 2007, the LED fuel program will reduce statewide NO_x emissions from on-road vehicles and non-road equipment by 30 tpd, of which 6.67 tpd of reductions will be achieved in the HGA ozone nonattainment area. The commission anticipates production cost will increase from $.04 to $.08 per gallon of diesel fuel to comply with rules.

The commission developed this NO_x emission control strategy to cover the eight counties contained in the HGA ozone nonattainment area. The coverage area also includes all counties in the state for on-road diesel fuel use; and the four DFW ozone nonattainment counties, the three BPA ozone nonattainment counties, as well as 95 central and eastern Texas counties for both on-road and non-road diesel fuel use. The involvement of the statewide and regional counties as part of the NO_x emission control strategy is necessary for the HGA and DFW areas to demonstrate attainment of the ozone NAAQS. These rules are intended to help bring the ozone nonattainment areas into compliance and to help keep attainment and near nonattainment areas from going into nonattainment by reducing emissions in those areas and by reducing transport of emissions into those areas. The state-wide and regional coverage will also provide a greater market for diesel fuel producers and importers to provide the fuel required by these regulations and avoid a patchwork of multiple requirements within the state. Additionally, the state-wide and regional coverage should help alleviate concerns regarding out-of-area refueling practices by making it difficult to refuel outside the covered area for use within a nonattainment or near nonattainment area.

The commission is open to considering future substitution of this measure if a federal program is completed and achieves substantially equivalent emission reductions. In addition, the commission is open to future agreements with entities for emission reductions from other fuel-related strategies. In order for agreements to be used, the commission may have to revisit these rules and the SIP to enable agreements to be considered for substitution of these rules.

The commission solicited comment regarding the possible benefits of reducing sulfur content to 15 ppm prior to the 2006 federal deadline as a possible alternative to controls on aromatics and cetane as proposed. There were two comments received which are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

The commission also solicited comment on additional flexibilities relating to rule content and implementation which have not been addressed in this or other concurrent rulemakings. These flexibilities may be available for both mobile and stationary sources. Additional flexibilities may also be achieved through innovative and/or emerging technology which may become available in the future. Additional sources of funds for incentive programs may become available to substitute for some of the measures considered here. There were two comments received which are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

SECTION BY SECTION DISCUSSION

The adopted amendments to §114.6 contain revisions to the following definitions: bulk plant, imported, import facility, importer, produce, and production facility. The amendment to the definition of bulk plant is needed for clarification of the definition and will insert the word "fuel" that was inadvertently left out of the original rulemaking. The phrase "solely by truck" is also amended to "by truck or pipeline" to account for those bulk plants that have pipeline delivery. These amendments to the definitions of imported, import facility, and importer are necessary to clarify that only those persons, except persons acting as common carriers, who import fuel into the state are covered by these definitions. These amendments will impact who is affected by the current requirements of the regional RVP gasoline program, specified in §§114.301, 114.304 - 114.307, and 114.309, as well as the amendments to the LED fuel program and will restrict the registration, reporting, and testing requirements of these programs to those persons who have direct control over changes in fuel content, i.e., those persons who produce fuel or import fuel into the state. The amendments to definitions of produce and production facility are necessary for clarification of these terms upon the repeal of the definitions of refiner and refinery. In addition, the amendments to §114.6 contain new definitions for common carrier, motor vehicle, and non-road equipment. The amendments to §114.6 also repealed the definitions of refiner and refinery. These definitions were repealed as being redundant with the terminology already being used for producer and production facility. Also, as a result of the new definitions, the other existing definitions are to be renumbered accordingly.

These amendments to §114.312 revise subsection (b) to modify the sulfur content standard for diesel fuel to provide for the phase down of sulfur content in certain affected areas from 500 ppm to 15 ppm. Subsection (b)(2) was deleted and subsection (b)(3) was renumbered in order to be consistent with anticipated federal rulemaking. The deadline for meeting 15 ppm sulfur has been changed from May to June to match the deadline proposed in the federal sulfur regulations. Subsection (b) has also been revised to clarify that 15 ppm fuel is not required until the compliance date identified in §114.319. The amendments to §114.312 also revise subsection (e) to provide clarifying changes to replace the terms, "refiner" and "refiner's refinery" with the term, "producer" and "production facility," as newly defined in §114.6. In addition, the amendments to §114.312 revise subsection (g) to provide reference to the testing methods prescribed in the adopted amendments to §114.315 and to change the reference prescribing which requirements may be satisfied by subsection (g) from subsection (a) to subsections (c) and (d) which was the original intent at proposal.

The amendments to §114.313 clarify the language of subsection (c) by adding commas in two locations.

The amendments to §114.314 clarify language by adding the word "fuel" after the phrase "low emission diesel (LED)." The amendments also change the word "chapter" to "division" to clarify that LED producers and importers shall comply with the requirements of the subchapter division regarding LED.

The amendments to §114.315 revise subsection (a) to establish the American Society for Testing and Materials (ASTM) Test Method D287-92(1995) as the approved test method for determining the American Petroleum Institute (API) gravity, ASTM Test Method D445-97 as the approved test method for determining viscosity, ASTM Test Method D93-99c as the approved test method for determining the flash point, and ASTM Test Method D86-00 as the approved test method for determining the distillation temperatures of the diesel fuel. The amendments to §114.315 also contain a new subsection (c) which establishes the test procedures and approval process for obtaining the executive director's approval of an alternative diesel fuel formulation, and a new subsection (d) which establishes the approval process for alternative diesel fuel formulations which are intended only for use in non-road equipment.

The amendments to §114.316 revise subsection (e) to require the California Air Resources Board (CARB) executive order number, or the approval notification number as issued by the executive director, to be included on the product transfer documents if the diesel fuel being transferred complies with one of those alternatives.

The amendments to §114.317 contain a new subsection (a) which establishes an exemption from the requirements of these rules for diesel fuel used for research, development, or testing purposes; new subsection (b) establishes an exemption for diesel fuel used for racing purposes; new subsection (c) exempts the owner or operator of a retail fuel dispensing outlet from all monitoring, recordkeeping, and reporting requirements of the rule, except for the requirement to maintain product transfer documents; the previous subsection (b) is renumbered to subsection (d); the language of subsection (d) is revised to provide an exemption that stipulates diesel fuel not meeting the LED requirements is not prohibited in the affected counties as long as it is not ultimately used to power a diesel fueled compression-ignition engine in a motor vehicle or non-road equipment in the affected counties, except for that fuel used in conjunction with research, development, or testing purposes, or as competition racing fuel. These exemptions were added to more closely match federal motor fuel regulations and are not expected to have a significant impact on air quality.

The amendments to §114.319 contain a new subsection (a) which establishes the compliance date for statewide coverage of the LED program for on-road diesel fuel use, a new subsection (b) which establishes the compliance date and coverage area for the use of LED for both on-road and non-road use, and a new subsection (c) which establishes the compliance date and coverage area for the sulfur content phase down to 15 ppm sulfur. Subsection (a) has also been revised to clarify that some requirements of §114.312 will not be applicable statewide. Finally, the proposed new subsection (c) which would have established a compliance date of May 1, 2004 and coverage area for the sulfur content to phase down to 30 ppm sulfur has been deleted in order to be consistent with anticipated federal rulemaking, and the proposed new subsection (d) has been renumbered to (c).

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed the rulemaking action 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 114 are intended to protect the environment or reduce risks to human health from environmental exposure to ozone and could affect in a material way, a sector of the economy, competition, and the environment due to its impact on the fuel manufacturing and distribution network of the state. The amendments are intended to implement an LED air pollution control program as part of the strategy to reduce emissions of NO_x necessary for the counties included in the HGA ozone nonattainment area to be able to demonstrate attainment with the ozone NAAQS.

These adopted rules do not meet any of the four applicability criteria for requiring a regulatory analysis of "major environmental rule" as defined in the Texas Government Code. Section 2001.0225 applies only to a major environmental rule the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

As discussed earlier in this preamble, this rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register,* or were included in the HGA SIP considered by the commission on December 6, 2000, and planned to be submitted to EPA by December 31, 2000.

The amendments are intended to implement an LED air pollution control program as part of the strategy to reduce emissions of NO_x necessary for the counties included in the HGA ozone nonattainment area to be able to demonstrate attainment with the ozone NAAQS. Specifically, the LED fuel requirements within these rules were developed in order to meet the ozone NAAQS set by the EPA under 42 USC, §7409, and therefore meet a federal requirement. This is based on the analysis provided in the rule proposal preamble which was published in the August 25, 2000 issue of the *Texas Register,* including the discussion in the Public Benefit and Costs section.

These rules do not exceed an express standard set by federal law, since they implement requirements of the FCAA. Provisions of 42 USC, §7410, require 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. These rules were specifically developed as part of an overall control strategy to meet the ozone NAAQS set by the EPA under 42 USC, §7409. 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 42 USC, Chapter 85, Air Pollution Prevention and Control). It is true that 42 USC 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 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. In order to avoid federal sanctions, 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. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commissions photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to achieve reductions in ozone precursor emissions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. By policy, the EPA requires photochemical grid modeling to demonstrate whether the 42 USC, §7511a(f), NO_x measures would contribute to ozone attainment. The commission has performed photochemical grid modeling which predicts that NO_x emission reductions, such as those required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The 42 USC, §7511a(f), exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under 42 USC, §7511a(f), was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

During the 75th Legislative Session, Senate Bill (SB) 633 amended the Texas Government Code to require agencies to perform a regulatory impact analysis (RIA) of certain rules. The intent of SB 633 was to require agencies to conduct an RIA of extraordinary rules. 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 adopted rules from the full analysis unless the rule was a major environmental rule that exceeds a federal law. As previously discussed, 42 USC 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 proposes and adopts SIP rules. The legislature is presumed to understand this federal scheme. If each rule adopted 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. Because 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. The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp,* 919 S.W.2d 485. 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue,* 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.,* 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert,* 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd,* Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor,* 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.,* 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore, in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, 382.017, 382.019, 382.037(g), and 382.039 authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

The commission solicited public comment on the draft RIA and received ten comments. These comments are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

TAKINGS IMPACT ASSESSMENT

The commission evaluated this rulemaking action and performed an analysis of whether the rules are subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. The specific purpose of the rulemaking action is to establish an LED fuel program which will act as an air pollution control strategy to reduce NO_x emissions necessary for the eight counties included in the HGA ozone nonattainment area and other nonattainment and near nonattainment areas of the state to be able to demonstrate attainment with the ozone NAAQS.

Texas Government Code, §2007.003(b)(4), provides that Chapter 2007 does not apply to these rules since they are reasonably taken to fulfill an obligation mandated by federal law. The rules fulfill federal mandates under the 1990 Amendments to 42 USC, §7410. 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 42 USC, §7409. States are primarily responsible for ensuring attainment and maintenance of NAAQS once the EPA has established them. Under 42 USC, §7410, 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. Any NO_x reductions resulting from the current rulemaking are no greater than what scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard. Consequently, one exemption which applies to these adopted rules is that of an action reasonably taken to fulfill an obligation mandated by federal law; therefore, these adopted rules do not constitute a takings under the Texas Government Code, Chapter 2007.

In addition, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. This action is taken in response to the HGA and other areas of the state exceeding the federal ambient air quality standard for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ozone levels in HGA. Consequently, these rules meet the exemption in §2007.003(b)(13).

The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking therefore meets the requirements of Texas Government Code, §2007.003(b)(4) and (13). For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

Comments received during the comment period regarding the TIA are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission determined that the rulemaking action relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et seq.), and the commission rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with the CMP. As required by 30 TAC §281.45(a)(3) and 31 TAC §505.11(b)(2), 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 reviewed this action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and determined that the action is consistent with the applicable CMP goals and policies. The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(1)). No new sources of air contaminants will be authorized and NO_x air emissions will be reduced as a result of these rules. The CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations in 40 CFR, to protect and enhance air quality in the coastal area (31 TAC §501.14(q)). This rulemaking action complies with 40 CFR 51, National Primary and Secondary Ambient Air Quality Standards, and with 40 CFR 52, Requirements for Preparation, Adoption, and Submittal of Implementation Plans. Therefore, in compliance with 31 TAC §505.22(e), the commission affirms that this rulemaking action is consistent with CMP goals and policies.

The commission solicited comments on the consistency of the proposed rules with the CMP during the public comment period, and received no comments.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000.

The following commenters provided oral testimony and/or submitted written testimony: AAE Technologies, Inc. (AAE); Ato Fina Petrochemicals (Ato Fina); Air Surrey Natural Gas Vehicles, Inc. (Air Surrey); Alliance of Automobile Manufacturers (Alliance); American Road and Transportation Builders Association (ARTBA); Associated General Contractors of Texas (AGC-Texas); Association of American Railroads (AAR); American Short Line and Regional Railroad Association (ASLRRA); Baker Botts LLP (Baker Botts); British Petroleum-Amoco (BP); Business Coalition for Cleaner Air (BCCA); CITGO Petroleum Corporation (CITGO); Canal Barge Company, Inc. (CBC); City of Baytown (Baytown); City of Corpus Christi (Corpus Christi); City of Fort Worth (Fort Worth); City of Lake Jackson (Lake Jackson); City of Missouri City (Missouri City); Clean Diesel Technologies, Inc. (CDTI); Corpus Christi Air Quality Committee (CCAQC); Corpus Christi City Councilman Arnold Gonzales (Councilman Gonzales); Dow Chemical Company (Dow); Dynegy, Inc. (Dynegy); Environmental Defense (ED); Ethyl Corporation (Ethyl); ExxonMobil Corporation (ExxonMobil); Galveston-Houston Association for Smog Prevention (GHASP); Grandparents of East Harris County (GEHC); Harris County Judge Robert Eckels (Harris County); Houston Metropolitan Transit Authority (Metro); Houston-Galveston Area Council (HGAC); Houston-Galveston Metropolitan Planning Organization's Transportation Policy Council (Houston MPO); Intercoastal Towing and Transportation Corporation (ITT); Kirby Inland Marine, Inc. (KIMI); Koch Petroleum Group LP (Koch); League of Women Voters of Texas (LWV-TX); Liberty County Sheriff Gregg Arthur (Liberty County Sheriff); Lyondell-CITGO Refining Company, Ltd (Lyondell-CITGO); Manufacturers of Emission Controls Association (MECA); RMT, Inc. on behalf of Montgomery County (Montgomery Co.); Mothers for Clean Air (MCA); National Association of Truck Stop Operators (NATSO); National Petrochemical and Refiners Association (NPRA); Paso del Norte Clean Cities Coalition (Paso del Norte); Phillips 66 Company (Phillips 66); Port Industries of Corpus Christi (Port Industries); Port of Corpus Christi Authority (PCCA); Texas Public Citizen (Public Citizen); Regional Air Quality Consensus Group (RAQCG); Reliant Energy, Inc. (REI); Sierra Club, Galveston Region (Sierra-Galveston); Sierra Club, Houston Regional Group (Sierra-Houston); State Representative Jaime Capelo (Representative Capelo); State Representative Vilma Luna (Representative Luna); State Senator Carlos F. Truan (Senator Truan); Suderman and Young Towing Company, Inc. (Suderman); Texas Association of Business and Chambers of Commerce (TABCC); Texas Citizens for a Sound Economy

(TCSE); Texas Department of Agriculture (TDA); Texas Motor Transportation Association (TMTA); Texas Oil and Gas Association (TxOGA); Texas Petroleum Marketers and Convenience Store Association (TPCA); Texas Waterway Operators Association (TWOA); United States Department of Defense (DoD); EPA; Ultramar Diamond Shamrock Corporation (UDS); Union Pacific Railroad Company (Union Pacific); Valero Refining Company - Texas (Valero); Wesly Community Center (Wesly); Western Towing Company (WTC); Willis Independent School District (WISD); and 57 individuals.

The following persons generally supported the proposal: AAE, Air Surrey, Alliance, Baker Botts, BP, CDTI, CCAQC, Councilman Gonzales, DoD, ED, EPA, Ethyl, Fort Worth, GEHC, GHASP, HGAC, Sierra-Houston, ITT, Lake Jackson, LWV-TX, MECA, MCA, Public Citizen, Representative Capelo, Representative Luna, Senator Truan, Houston MPO, Wesly, WISD, and 38 individuals.

The following persons generally opposed the proposal: ARTBA, Ato Fina, AGC-Texas, AAR, ASLRRA, BCCA, CITGO, CBC, Baytown, Corpus Christi, Missouri City, Dow, Dynegy, ExxonMobil, Sierra-Galveston, Harris County, KIMI, Koch, Lyondell-CITGO, Liberty County Sheriff, Metro, Montgomery Co., NATSO, NPRA, Phillips 66, Port Industries, PCCA, Paso del Norte, RAQCG, REI, Suderman, TABCC, TCSE, TDA, TMTA, TPCA, TWOA, TxOGA, UDS, Union Pacific, Valero, WTC, and 19 individuals.

The following persons suggested changes to the proposal as stated in the ANALYSIS OF TESTIMONY section of this preamble: AAE, AAR, ASLRRA, AGC-Texas, Air Surrey, ARTBA, Ato Fina, Baker Botts, Baytown, BCCA, BP, CBC, CITGO, Corpus Christi, Houston MPO, DoD, Dow, Dynegy, EPA, Ethyl, ExxonMobil, Sierra-Galveston, GEHC, GHASP, Harris County, HGAC, Sierra-Houston, KIMI, Koch, Lyondell-CITGO, Liberty County Sheriff, MECA, Montgomery Co., NATSO, NPRA, Phillips 66, Port Industries, PCCA, Paso del Norte, RAQCG, REI, Suderman, TABCC, TCSE, TDA, TMTA, TPCA, TWOA, TxOGA, UDS, Union Pacific, Valero, WTC, and 15 individuals.

ANALYSIS OF TESTIMONY

AGC-Texas, Ato Fina, Baytown, BCCA, CITGO, Corpus Christi, Dow, Dynegy, ExxonMobil, Harris County, Koch, Lyondell-CITGO, NATSO, NPRA, Phillips 66, RAQCG, REI, TABCC, TxOGA, TPCA, UDS, Valero, and eight individuals expressed opposition to all region-specific, patchwork, or boutique fuel control strategy methods and requested that the commission refrain from implementing the proposed rules. Instead, they supported and encouraged the adoption of new federal diesel fuel regulations which are forthcoming in the near future. The new federal regulations will provide virtually identical NO_x emission reduction benefits at a much lower cost to the public. Koch recommended that the commission withdraw this proposed rule and refrain from seeking a waiver from EPA to regulate diesel in Texas. TxOGA commented that the proposed federal low sulfur diesel fuels should supercede these proposed rules if they are adopted by the commission. TxOGA strongly recommended that the commission repeal all portions of these rules, including the rules regarding aromatics and cetane, as soon as the federal rule is adopted.

The HGA ozone nonattainment area is required to have three years of emissions monitoring data demonstrating compliance with the NAAQS to support the 2007 attainment demonstration. Therefore, implementing the LED standards in May 2002 provides the area the necessary time to allow the results of this control strategy to be realized through ozone monitoring data. In addition, these rules provide state requirements for non-road diesel fuel use which is not currently addressed by federal regulation. The commission is also aware that the EPA has issued a notice of proposed rulemaking (NPRM) for new heavy-duty engine and vehicle emission standards and new diesel fuel standards. If the outcome of this EPA proposal is a federal rule which covers the areas in Texas impacted by these adopted rules, and the federal rule is at least as stringent as any rules adopted as a result of this rulemaking, then the commission will consider compliance with the national rule equally effective and may repeal all or portions of the state requirements for diesel fuel. However, based on the NPRM, it is quite likely that the EPA will only mandate sulfur reductions for on-road use, leaving aromatics and cetane values at their current levels. Because the EPA believes that the 2004 emission standards can be met without recourse to NO_x after-treatment devices, sulfur reductions alone are not expected to generate further NO_x reductions beyond the engine standards themselves. The commission has made no change to the rule language in response to this comment.

NPRA commented that the United States House of Representatives Committee on Science recently requested the United States Department of Energy (DOE), Energy Information Administration (EIA) to conduct a study of the EPA proposed 15 ppm sulfur cap on highway diesel and that the EIA indicated that this study will not be completed until April 2001, and therefore NPRA recommended that the commission either withdraw the LED proposal or defer promulgation of this proposal until after the commission has received and considered next year's EIA report.

The commission believes that there is currently adequate information available to support the adoption of these rules. The timeline deemed necessary by the commission to allow fuel producers sufficient time to comply with these rules and to allow the commission to meet SIP submission requirements has made adoption of the rules necessary at this time. The commission has pledged to reconsider all of it rules concerning the HGA attainment strategies during the mid-course review in the 2003 to 2004 time frame. Since the 15 ppm sulfur requirement does not begin until 2006 under these rules, the current timeline would allow the commission to reconsider the rules in light of new information which may be contained in the EIA report.

One individual commented that these proposed rules appear to be set up to embarrass Texas and the Governor and that these proposed rules go far beyond anything necessary to protect the environment. This individual further added that the basis and analysis behind these proposed rules is flawed and should be reevaluated.

The commission intent is not to embarrass Texas and the Governor, but instead to comply with the timelines provided in 1990 FCAA amendments and subsequent EPA guidance for submitting rules to demonstrate ozone attainment in HGA. Accordingly, the commission has committed to adopting the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000.

As noted in the rule preamble, the purpose of these rules is to establish an LED air pollution control strategy that reduces NO_x emissions necessary for the HGA nonattainment area to be able to demonstrate attainment with the ozone NAAQS. The science behind cleaner-burning fuels is well established. The emission reductions anticipated by the implementation of these rules are necessary to the success of the area in reaching attainment and therefore the commission deemed it necessary for inclusion in the SIP. As demonstrated in the SIP, the strategies do not require more reductions than necessary to meet federal air quality standards.

NPRA recommended that implementation of new diesel fuel sulfur standards should not occur before 2010. CITGO commented that reducing sulfur prior to the introduction of the new heavy-duty engine vehicles, and to a level lower than that required to enable technology, will provide minimal benefit in reducing NO_x and is certainly not cost effective.

The commission disagrees with this comment. Advanced diesel engine emission control systems needed by the diesel engine manufacturers to comply with the proposed 2007 federal heavy-duty diesel engine emission standards will require ultra-low sulfur diesel fuel to operate efficiently. Therefore, the commission is requiring reductions in diesel fuel sulfur beginning in June 2006. The commission removed the requirement for 30 ppm sulfur in calendar year 2004 for the reasons specified in the SECTION BY SECTION DISCUSSION.

The Liberty County Sheriff expressed his concerns over who is going to enforce these proposed regulations. One individual commented that the commission needs to convey the strategies it plans to use to enforce these proposed rules and that an efficient quality-assurance and enforcement program must be developed and be part of the SIP document for reformulated liquid fuels to be a credible component in the SIP.

As with all of its rules, the commission will enforce the requirements after the rule compliance date and take appropriate action for noncompliance situations, including situations in which a grandfathered source has modified its operations without first obtaining the required permit authorization under 30 TAC Chapter 116 or Chapter 106. The rules are enforced by staff in the commission's regional offices, as well as local air pollution control programs. Local governments have the same power and are subject to the same restrictions as the commission under TCAA, §382.015, Power to Enter Property, to inspect the air and to enter public or private property in its territorial jurisdiction to determine if the level of air contaminants in an area in its territorial jurisdiction meet levels set by the commission. Local governments are not required to enforce commission rules, but may sign cooperative agreements with the commission to enforce the rules under TCAA, §382.115, Cooperative Agreements. Local programs can also enforce commission rules without signing a cooperative agreement. The authority of local governments to enforce air pollution requirements is specified in detail in TCAA, §§382.111 - 382.115, and local governments can institute civil actions in the same manner as the commission under Texas Water Code (TWC), §7.351.

The commission will work with local officials to ensure enforcement of the SIP and SIP rules. The commission has existing relationships with pollution control authorities in the City of Houston, Harris County, and Galveston County for enforcement of other commission rules. The agency will continue enforcement relationships with these entities and develop relationships with other local officials as needed to create effective enforcement mechanisms for the SIP and SIP rules.

The EPA commented that the commission should explain how the proposed rules prohibit transport, supply, etc. of non-complying diesel fuel, and make any person in the distribution system liable for such a violation.

The rules require all parties in the distribution chain to maintain copies or records of product transfer documents for a minimum of two years. It is clear in the rules that each party in the distribution chain is required to comply with the rules, and, as with any rule, is subject to enforcement action for a violation. As with all of its rules, the commission will enforce the requirements after the compliance date and will take appropriate action for noncompliance situations. The commission made no change to the rule language in response to these comments.

HGAC and Sierra-Houston commented that the proposed rules should be implemented statewide to provide adequate market and to maximize emission benefits for the 2007 attainment data. Four individuals commented that the proposed rule should be applied statewide. One individual commented that the proposed low-sulfur diesel should be delayed until the federal mandate applies across the country or it should be applied across the entire state since there is a high likelihood of shortages due to refinery limitations. GHASP commented that the sulfur concentration in all fuel be reduced to 15 ppm.

As noted in the rule preamble, the rules do apply statewide regarding the requirement for the use of diesel fuel with 500 ppm maximum sulfur, 10% maximum aromatics, and 48 minimum cetane, for on-road use in motor vehicles. In this rulemaking, the commission cannot revise these proposed rules upon adoption to apply the reductions of sulfur in 2006 for both on-road and non-road use statewide or to other counties in Texas because the additional affected parties would not have had adequate notice and opportunity to comment. Additionally, requirements on any fuel but diesel is outside the scope of this rulemaking. However, the commission will consider the need to expand the rules during the mid-course review scheduled to be completed by May 1, 2004. The commission made no change to the rule language in response to these comments.

HGAC commented that the commission should encourage introduction of cleaner fuels nationally, including cleaner diesel fuel.

The commission provided comments to the EPA in support of the proposed federal heavy-duty diesel engine standards and low sulfur diesel fuel rules.

Paso del Norte commented that studies conducted on improved diesel, so-called clean diesel, have shown that improving diesel causes other problems, including other types of cancers and other related health problems, that the commission should analyze before adopting this proposal.

The commission disagrees with this comment. The differences between conventional diesel fuel and the clean, or "reformulated," diesel fuel are that clean diesel fuel contains less sulfur, less polycyclic aromatic compounds (PAC), and an increase in cetane. The commission has conducted a literature search and has not discovered any studies supporting the claim that the clean diesel causes different types of cancers or other related health problems. However, the literature does indicate that fuels with lower sulfur and PAC levels are potentially less biologically hazardous. The commission is of the opinion that a clean diesel formulation, such as the LED required by these rules, will reduce the overall hazard potential. The commission made no change to the rule language in response to this comment.

Koch commented that the commission should request the EPA to allow the state to take credit in the SIP for reductions that will be achieved through the implementation of the proposed federal heavy-duty diesel engine standards and low sulfur diesel fuel program.

Because the EPA is still in the NPRM stage of this rulemaking process, the commission cannot claim credit for this proposed initiative. In addition, based on the NPRM, it is likely that the EPA will only mandate sulfur reductions, leaving aromatics and cetane values at their current levels. Because the EPA believes that the 2004 emission heavy-duty diesel emission standards can be met without recourse to NO_x after-treatment devices, sulfur reductions alone are not expected to generate further NO_x reductions beyond the engine standards themselves. With regard to obtaining credit for "low emission diesel vehicles," the commission has modeled the effects of heavy diesel vehicles meeting the 2004 emission standards, and included these results in the 2007 emission projections. For these reasons the commission believes the SIP modeling effort has already claimed the maximum amount of NO_x reduction credits available from diesel vehicles and fuels, given the current federal rulemaking status.

Koch and TxOGA responded to the commission's request for comments regarding the possible benefits of reducing sulfur to 15 ppm prior to the 2006 federal deadline as a possible alternative to controls on aromatics and cetane by commenting that Koch and TxOGA do not recommend the early implementation of ultra-low sulfur diesel prior to the introduction of advanced technology engines and catalysts that must utilize low sulfur diesel. Koch and TxOGA further added that early introduction of ultra-low sulfur diesel fuel will not provide the intended air quality benefits, nor will it make any difference in the SIP accounting that is to take place in 2007.

The commission appreciates the response to our request for comments and has revised the rule to delete the proposed requirements which would have required 30 ppm sulfur by May 1, 2004 in order to provide greater flexibility for producers to comply with these rules and to be consistent with anticipated federal rulemaking.

Koch and TxOGA responded to the commission's request for comments regarding additional flexibility relating to rule content and implementation. Commenters indicated that the flexibility embodied in the proposed federal diesel rule that allows adequate time to make changes to their refineries to reduce sulfur levels is an excellent example of allowing industry to reasonably comply with the rule and to smooth supply transitions for cleaner burning fuels. The flexibility allowed by the federal rule is the critical reason Koch and TxOGA opposed the proposed rules and supported the federal proposal for the HGA area.

The commission appreciates the response to our request for comments and has taken these comments into consideration.

BCCA and TxOGA expressed opposition to the waiver request being submitted to the EPA by the commission in accordance with 42 USC, §7545(c)(4)(C) to implement the on-road portion of the proposed rules and expressed support for the proposed federal low sulfur diesel rules.

The commission contends that the waiver request is necessary for implementation of the on-road portion of the rules and that the rules will provide greater emission reduction benefits than the proposed federal low sulfur diesel rules from the reduction in aromatic content and an increase in cetane level. Therefore, the commission is requesting this waiver from the EPA.

The EPA commented that the commission should provide further explanation in the 42 USC, §7545(c)(4)(C) waiver request for what other control measures were examined and the reasons for discarding these measures.

The commission believes that sufficient data are being provided in Appendix L of the HGA Post-1999 ROP/Attainment Demonstration SIP regarding the various alternate control strategies that were reviewed to determine whether the proposed implementation of the LED fuel control strategy is justified to be included as part of the attainment demonstration. The commission revised Appendix L to ensure that the waiver request addresses the EPA concerns.

The EPA commented that the commission should better address in the 42 USC, §7545(c)(4)(C) waiver request the reasoning for expanding the on-road measure of the proposed rules statewide and why it is necessary for attainment. UDS expressed opposition to the state-wide coverage of the proposed rules and asked why the commission is requiring all of the citizens of Texas to share the cost burden associated with the proposed rules when their additional costs provides so little real benefit to the HGA area. UDS further added that this strategy should not be extended to other areas that are currently in attainment, or who may be designated nonattainment this summer, and that the commission should examine all potential cost effective strategies before implementing a regulation mandating a fuel standard as stringent as the proposed LED standard. ExxonMobil commented that the commission has not shown a scientific basis for requiring state-wide coverage for the proposed rules, nor has it demonstrated that state-wide boutique fuels are necessary to attain the ozone standard in the HGA area. ExxonMobil further added that the commission has shown no demonstration that the proposed fuel is necessary to maintain air quality in attainment areas. Koch commented that state-wide application of a rule designed to bring a nonattainment area into attainment is inappropriate from outright lack of air quality need. BCCA commented that a boutique fuel is not needed to maintain attainment outside of the HGA area and that requiring a special, boutique fuel for areas of Texas that are in attainment with all air quality standards has no technical, regulatory, or legal basis.

As noted in the rule preamble, the commission expanded the rules to cover the entire state as a means to help alleviate concerns regarding out-of-area refueling practices in relation to the nonattainment counties and to reduce the regional transport of ozone precursors. Federal and state studies have shown that pollution from one area can affect ozone levels in another area. This work is supported by the findings of the OTAG study, which is the most comprehensive attempt ever undertaken to understand and quantify the transport of ozone. Both the commission and the OTAG study results point to the need to take a regional approach to control air pollutants, such as that prescribed in the rules. The state-wide implementation of LED fuel will help reduce the amount of NO_x being transported into the HGA, BPA, and DFW ozone nonattainment areas and other areas of the state having concerns over air quality. The state-wide coverage will also provide a greater market for diesel fuel producers and importers to provide the fuel required by these regulations. The commission and local area evaluated over 250 possible strategies while developing the attainment demonstration. These were identified in Appendix L of the SIP submittal. Modeling assessing the benefits of these rules demonstrated that by the year 2007, the use of LED will reduce NO_x emissions in the HGA ozone nonattainment area by 6.48 tpd, and statewide by 30 tpd. The commission clarified the SIP language to ensure the waiver request addresses the EPA concerns.

Koch commented that the commission should consider allowing marketable credit for the use of premium diesel fuels, which use advanced performance additives to achieve superior deposit control and corresponding in-use emission benefits, instead of mandating a low emission diesel fuel. AAE commented that its OxyDiesel clean diesel fuel formulation should be included in the proposed rules among the options for the HGA area for on-road and nonroad diesel-powered vehicles and equipment.

The rules allow the use of alternative formulations that provide emission reductions equivalent to the specified fuel content standards for aromatics and cetane. However, the alternative formulation must comply with the sulfur standard as specified in the rule. The commission made no change to the rule language in response to this comment.

Corpus Christi expressed opposition to the commission proposal to include Nueces and San Patricio Counties in the coverage area of the proposed rules and requested comment on how the boundaries of the coverage area were determined and justified. Corpus Christi further requested comment on how the commission's accelerated implementation schedule, as compared to the proposed federal implementation schedule, can be justified in Nueces and San Patricio Counties. These counties are remote from the HGA area, are currently in attainment of the ozone NAAQS, and any benefit to the air quality of the HGA area from the fuel purchased in Corpus Christi would be non-detectable. PCCA and Port Industries commented that unless sound science demonstrates that emissions from the Corpus Christi area, an attainment area, contribute to the nonattainment status of the HGA or other nonattainment areas, the commission should refrain from imposing controls on Nueces and San Patricio Counties and recommended that Nueces and San Patricio Counties be removed from the proposed coverage area. Port Industries further added that the commission should support a renewal of the Flexible Attainment Region agreement that has proven successful in the Corpus Christi area and that the commission should support initiatives for voluntary efforts instead of the proposed mandatory requirements.

These rules are an element of an integrated regional ozone control strategy. The commission has expanded the rules to cover the entire state as a means to help alleviate concerns regarding out-of-area refueling practices in relation to the nonattainment counties and to reduce the regional transport of ozone precursors. Federal and state studies have shown that pollution from one area can affect ozone levels in another area. This work is supported by the findings of the OTAG study, which is the most comprehensive attempt ever undertaken to understand and quantify the transport of ozone. Both the commission and the OTAG study results point to the need to take a regional approach to control air pollutants, such as that prescribed in the rules. The state-wide implementation of LED fuel will help reduce the amount of NO_x being transported into the HGA, BPA, and DFW ozone nonattainment areas and other areas of the state having concerns over air quality. As such, the commission is not removing the Corpus Christi area from the clean diesel regulations. The state-wide coverage will also provide a greater market for diesel fuel producers and importers to provide the fuel required by these regulations. The commission revised the rule to delete the proposed requirements which would have required 30 ppm sulfur by May 1, 2004 in order to be consistent with anticipated federal rulemaking and implementation schedules.

Montgomery County commented that the elimination of Montgomery County from the proposed rule coverage area would result in a difference of 1/200th of a ppb (0.005 ppb) of ozone and recommended that Montgomery County be exempted from the proposed rules. The Liberty County Sheriff commented that the commission should exempt Liberty County from the proposed rules.

The FCAA Amendments of 1990 provided new requirements for areas that had not attained the NAAQS for ozone, carbon monoxide, particulate matter, sulfur dioxide, nitrogen dioxide, and lead, and new requirements for SIPs in general. The EPA was authorized to designate areas failing to meet the NAAQS for ozone as nonattainment and to classify them according to severity. FCAA, §107(d)(4)(A)(iv) mandated that areas designated as serious, severe or extreme for ozone that were within a metropolitan statistical area (MSA) or CMSA must have boundaries that include the entire MSA or CMSA. This requirement is supported by the legislative history for the FCAA Amendments in Senate Report No. 101-228, page 3399, "Because ozone is not a local phenomenon but is formed and transported over hundreds of miles and several days, localized control strategies will not be effective in reducing ozone levels. The bill, thus, expands the size of areas that are defined as ozone nonattainment areas to assure that controls are implemented in an area wide enough to address the problem." The FCAA Amendments did provide the ability to exclude portions of the entire MSA or CMSA prior to designation, if the state conducted a study that EPA agreed proved that the geographic portion did not contribute significantly to violation of the NAAQS.

Montgomery County is a nonattainment county. Redesignation has not occurred for any portion of the HGA nonattainment area, and is not currently being considered. For existing areas currently included within a nonattainment area, the specific area must be redesignated as attainment to be removed from a nonattainment area. FCAA, §107(d)(3) provides that EPA may not redesignate a nonattainment area, or a portion thereof, to attainment unless several criteria are met, which include: a determination that the area has attained the NAAQS; there is a fully approved SIP for the area; there is a determination that the improvement in air quality is due to permanent and enforceable reductions in emissions; there is an approved maintenance plan for the area; and the state has met all requirements for the area under FCAA, §110 and Part D.

However, even if a specific area within the HGA nonattainment area was redesignated by the EPA as attainment for ozone, reductions associated from all adopted ozone control strategies would still be necessary because of the requirements of FCAA, §107(d)(3) and §175A which require maintenance plans for all redesignated areas. The maintenance plan must include the measures specified in §107(d)(3) and any additional measures that are necessary to ensure that the area continues to be in attainment with the NAAQS for ten years after the redesignation. Eight years after the redesignation, the state is required to submit an additional revision to the SIP for maintaining the NAAQS for ten years after the end of the first ten-year period.

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies.

At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The commission conducted air quality modeling and upper air monitoring that found regional air pollution should be considered when studying air quality in Texas' ozone nonattainment areas. This work is supported by research conducted by the OTAG, the most comprehensive attempt ever undertaken to understand and quanitfy the transport of ozone. Both the commission and the OTAG study point to the need to take a regional approach to controlling air pollutants.

The AAR, ASLRRA, and Union Pacific commented that there is no data showing that diesel fuel meeting the proposed fuel parameters would have a beneficial effect when used in locomotives, especially considering the significant increase in costs that would occur. The AAR, ASLRRA, and Union Pacific further added that while EPA is considering adoption of stringent sulfur limitations for the purpose of enabling new engine and after-treatment technologies that are sensitive to sulfur, it has not suggested that railroads would be subject to these new requirements since locomotive manufacturers are not expected to rely on the technologies the EPA has identified as being sensitive to sulfur, such as catalysts and particulate filters, for the foreseeable future.

The commission believes that the reduced sulfur and aromatic content level and the increased cetane level in the LED fuel will provide an emissions benefit when used in locomotive engines and that the control of non-road diesel fuel is necessary in terms of retrofit technology for demonstrating attainment with the ozone NAAQS. The use of LED fuel will be beneficial to areas of the state that are currently seeking voluntary actions from the railroad industry to use newer technology engines while operating in their areas. There are additional reductions of emissions when the low sulfur level is coupled with a reformulation that has lower diesel fuel aromatic content regardless of engine technology. The commission made no change to the rule language in response to this comment.

Two individuals commented that mandates for cleaner buses and big trucks are also necessary. Two individuals commented that the commission should require all city buses, big trucks, and other transportation to use 'clean fuel,' by 2007.

There are many federal and state mandates for reducing emissions from transit buses and large trucks, including the EPA Urban Bus Rebuild Program, the EPA 2004 heavy-duty engine standards, the EPA expanded Tier II engine standards (up to 14,000 pounds (lbs) GVWR), and the Texas Clean Fleet Program (up to 26,000 lbs GVWR). The EPA is also proposing new 2007 heavy-duty diesel engine standards. Regarding clean fuel, the state rules will require ultra-low sulfur LED for on-road and non-road use in the DFW and HGA nonattainment areas and an additional 95 central and eastern Texas counties by 2007. The commission made no change to the rule language in response to this comment.

Paso del Norte commented that the commission should be moving toward the use of cleaner alternative fuels rather than requiring cleaner diesel fuel. One individual commented that the commission should provide incentives for the use of compressed natural gas (CNG), liquified natural gas, ultra-low emission vehicles, and catalysts and filters on all internal combustion engines and that the state road tax should be used to fund the incentives. One individual commented that the commission should promote the use of propane as a transportation fuel. One individual commented that the commission should promote the use of CNG. Air Surrey commented that it had a software tool the commission could use to justify and speed up the switch over from gasoline and diesel to relatively non-polluting compressed natural gas motor vehicle fuel in the state's urban areas. One individual commented that alternative fuels have not been fully proven.

The commission acknowledges that the use of alternative fuels in specific situations may provide air quality benefits and that tax credits are one of many incentive strategies that could be used to promote the use of alternative fuels. The commission chose to regulate diesel because the greater penetration of the fuel in heavy-duty market will result in faster reductions of NO_x. In addition, LED allows for the implementation of retrofit technologies which will result in even greater reductions of NO_x from existing diesel engines. However, as no provisions concerning the use of alternative fuels were included in the proposed rules, these comments are outside the scope of this rulemaking.

TWOA commented that the proposed rule would be ineffective in regard to tug/towboat applications due to the fact that 15 ppm sulfur diesel would be more expensive, causing tug/towboat operators to avoid fueling in the HGA area. WTC commented that the commission cannot enforce the proposed rules on tug/towboat operations as the majority of its fuel is purchased outside of the state and the commission's jurisdiction.

The commission acknowledges that there could be an estimated $.08 per gallon increase in fuel costs as a result of these rules. The commission also acknowledges that it has no jurisdiction outside the borders of this state. These rules are enforced against the diesel fuel suppliers, not the users. The commission recognizes that some out-of-state refueling may occur and has therefore broadened the program area to lower the likelihood that will occur.

TWOA commented that requiring tug/towboats operating in the HGA to utilize 15 ppm sulfur diesel fuel creates safety risks because many tug/towboat engines utilize diesel fuel as a lubricant and the drier ultra-low sulfur diesel could cause failures of these engines thereby creating collision and pollution hazards.

The commission disagrees with this comment. All currently used or proposed low sulfur diesel fuels are designed to meet the ASTM viscosity specification or the ASTM standard for lubricity. The low sulfur diesel fuels currently in use, such as CARB diesel (15 ppm), Swedish diesel (10 ppm), ARCO-BPAmoco (9 ppm), have not demonstrated any lubricity problems with the fuel injection and/or supply systems. Since the low sulfur diesel fuels are designed to meet the specification for lubricity based on ASTM standards, there should be no lubricity problem associated with fuel systems due to their ultra-low sulfur contents. The commission made no changes to the rule language in response to this comment.

TWOA requested comment on how does the commission propose to overcome the mixing of multiple fuels with multiple sulfur contents, from multiple tug/towboats coming from multiple states and how is the commission going to assure the EPA that the proposed rule will actually reduce the sulfur level of fuels to 15 ppm. TWOA further requested comment on how has the commission accounted for the sulfur contents of oils that enter the engine and increase the sulfur content of the fuel beyond 15 ppm. Three individuals commented that the commission should consider measures to ensure trucks crossing borders into Texas, or from other Texas regions, are also running on low sulfur diesel. One individual commented that the commission needed to implement a widely deployed field-test system to rapidly determine if a vehicle's fuel is contaminated with high-sulfur fuel.

The commission acknowledges that it cannot control out-of-state or country fuel purchases and that there may be commingling of fuel with differing sulfur levels in individual vessels and vehicles. The rules apply to the distribution of LED within the covered area, not whether individual vehicles may have noncompliant fuel within their fuel tanks. However, the rules will ensure that local fuel purchases comply with the LED sulfur requirements. In addition, the proposed EPA 2007 heavy-duty diesel engine and vehicle standards and highway diesel fuel sulfur control requirements which require the nationwide use of 15 ppm sulfur for on-road motor vehicles in June 2006 will help alleviate concerns over commingling.

While diesel engine lubricating oils do indeed have a relatively high concentration of sulfur (2,500 - 8,000 ppm by weight), these oils do not appear to have a large impact on exhaust sulfur levels. According to EPA's *Draft Heavy-Duty Standards Regulatory Impact Analysis* of May 2000, the equivalent fuel sulfur level increase resulting from a 5,000 ppm lubricant is approximately one ppm. Therefore even at fuel sulfur levels as low as 15 ppm, incremental increases remain quite low.

In addition, the sulfur standard is proposed primarily for the purposes of technology enablement, allowing aftertreatment devices such as selective catalytic reduction (SCR) to operate properly in the future. However, the commission's emission benefit calculations do not account for the effect of such devices by 2007. Since an increase in sulfur does not increase NO_x unless aftertreatment devices are involved, any increase in sulfur from lubricants would not affect the total NO_x reduction estimates. The commission made no changes to the rule language in response to these comments.

TWOA strongly recommended that the commission remove the tug/towboat industry from the proposed rule because of the insurmountable issues associated with engine performance and the fact that the majority of the diesel fuel used by this industry is purchased outside of the area under the jurisdiction of the commission.

The control strategies being implemented by the commission in the HGA nonattainment area are necessary to the area's federal requirement to demonstrate attainment by 2007 and all possible reductions are needed. The commission believes that tug/tow boats are a contributing emission source in the HGA area and that it would not be appropriate to exclude them from these rules. The commission made no change to the rule language in response to this comment.

Sierra-Galveston commented that the commission should adopt the California standards for low sulfur fuels.

The commission believes that the LED fuel program will provide more emission reductions benefits than California diesel fuel standards, mainly due to the addition of minimum cetane requirements in the Texas rules. The commission made no change to the rule language in response to this comment.

GEHC commented that the commission could solve a lot of the pollution reduction problems with airport ground equipment, large trucks, locomotives, and marine vessels by requiring cleaner-burning diesel fuel.

As noted in the rule preamble, the rule requires LED for on-road use statewide and for both on-road and non-road use in the DFW and HGA nonattainment areas and an additional 95 central and eastern Texas counties in the regional area. The requirement for non-road use of LED will impact airport ground equipment, locomotives, and marine vessels equipped with diesel fueled engines and large diesel fueled trucks will be impacted by the on-road LED use requirement. The commission made no change to the rule language in response to this comment.

One individual commented that the commission should consider other options that should include forcing refineries to change diesel formulations to remove more toxins.

The commission shares the commenter's concern regarding toxins. The commission anticipates that the limits on aromatics in the rules will result in reductions in toxics in diesel fuel. The commission made no changes in the rule language in response to these comments.

One individual commented that requiring the use of low sulfur/low aromatic fuels for all types and forms of internal combustion (I/C) engine use has been delayed too long and that Sweden and Germany are moving to ten ppm sulfur liquid fuels and expect to market five ppm fuel.

The commission is aware of the diesel fuel standards that are being proposed for Europe. However, the NO_x benefits of ultra-low sulfur diesel fuels are dependent upon advanced emission control technologies, such as NO_x catalytic converters and particulate filters. Requiring such fuels before the technology is available does not guarantee NO_x emission reductions. The commission's timing of the sulfur requirement is to ensure that it is available when federal diesel engine standards are implemented.

One individual commented that the cost of plant modification distributed over 20 years of plant life must be considered against the reduced costs of child and adult health care accruing from breathing cleaner air with reduced ozone and PM concentrations.

The commission evaluated previous studies, such as those conducted by the EPA and the DOE, regarding the estimated economics of producing low sulfur diesel fuel and believes that these studies provide sufficient cost benefit analysis to justify the data included in the fiscal impact section of the rule preamble. The commission agrees with the commenter that the benefits of these rules include public health improvements.

Three individuals commented that low sulfur/low aromatic gasoline and diesel fuels are essential for the effective use of current catalytic and filter technologies to reduce I/C engine exhaust-gas pollutants and be consistent with an acceptable catalyst life, avoiding catalyst poisoning.

The commission agrees with this comment.

One individual commented that a tax relief credit for conversion to, and use of, low sulfur fuels should be made available for three years. Alternatively the excise tax on this fuel must make it cheaper per gallon at the pump than non-reformulated equivalent fuel. A well-funded Carl Moyer type program would help the multiple small firms make the conversion. One individual commented that the commission should promote the use of low sulfur, low aromatic fuels and subsidize the cost so that these fuels are less expensive than the standard fuels.

The commission agrees that economic incentive programs can potentially be an effective tool for achieving air quality. One such program is the Carl Moyer program in California. That program appears to be successful in providing flexibility to the regulated industry while still achieving reductions in air emissions. The California program is authorized by and funded through the state legislative process and such legislative approval does not currently exist for a similar Texas program. The commission will continue to try to identify economic incentives which it has authority to implement. Because the commission agrees that market-based incentive programs can be an important component in encouraging development of new technologies and/or greater or more cost-effective emission reduction strategies, the commission provided for the inclusion of economic incentive programs as a component of the HGA SIP in the future.

The commission does not have the authority to make changes to any state taxes or offer fuel tax credits. Only the legislature has the authority to modify state tax regulations. Currently, 30 TAC Chapter 117, Tax Relief for Property Used for Environmental Protection, is the commission's program that provides tax relief for the purchase of pollution control property. On November 2, 1993, the voters of Texas approved a constitutional amendment, commonly referred to as "Proposition 2," that provides an exemption from property taxation for pollution control property. The intent of the constitutional amendment was to ensure that capital investment undertaken to comply with federal, state, or local environmental mandates did not result in an increase in a facility's property taxes. Legislation implementing that amendment, House Bill 1920, was passed during the 73rd Texas Legislative Session which added a new §11.31 and §26.045 to the Texas Tax Code (Tax Code). The Tax Code provides that pollution control property could include any land purchased after January 1, 1994, or any structure, building, installation, excavation, machinery, equipment, or device and any attachment or addition to or reconstruction, replacement, or improvement of property that is used, constructed, acquired, or installed wholly or partly to meet or exceed rules or regulations adopted by any federal, state or local environmental agency for the prevention, monitoring, control or reduction of air, water, or land pollution. Motor vehicles are specifically noted as being ineligible for an exemption under this provision of the Tax Code. The Tax Code contains a two-step process for securing an exemption from property taxes for pollution control property. An applicant must first receive a determination from the commission that the property is used for pollution control purposes. The applicant then can use this determination to apply to the local appraisal district for a property tax exemption. The commission made no change to the rule language in response to this comment.

Koch and TxOGA expressed strong concerns that LED product availability was not given proper consideration in the proposed rulemaking and the timing is out of sync with the proposed federal diesel requirements. CITGO, ExxonMobil, Koch, Lyondell-CITGO, NPRA, TxOGA, and Valero expressed concern that the proposed rule will lead to supply disruptions and product outages as well as price volatility which will have a severe negative impact on supplies of on-road and non-road diesel fuel in the state. BCCA commented that the proposed LED presents a much higher market risk and uncertainty for diesel supplies throughout east Texas than the proposed federal low sulfur diesel fuel rule because the proposed LED rule will reduce regional diesel fuel supplies, reduce incentives for refiners to invest in low sulfur diesel facilities, and limit refiner's ability to build new facilities. TCSE commented that requiring the sale of more costly low emission diesel will cause tremendous economic disruption in the state and hurt the public.

The commission revised the rule to delete the proposed requirements which would have required 30 ppm sulfur by May 1, 2004 in order to provide greater flexibility for producers to comply with these rules and to be consistent with anticipated federal rulemaking and implementation schedules.

TxOGA commented that even if the refiners willing to comply with the proposed LED requirements can manufacture sufficient supplies of LED, it does not believe that the existing distribution system can provide continuous and ample supplies of a 15 ppm diesel fuel for Texas while products containing significantly higher sulfur levels are being shipped in the same delivery system. BCCA commented that the existing fuels distribution infrastructure is not currently sufficient to deliver Texas boutique fuels to the marketplace in a timely fashion. NATSO and NPRA expressed opposition to the proposed reduction in sulfur to 30 ppm in 2004, a full two years ahead of the proposed federal standard, and commented that it would seriously jeopardize the integrity of the region's fuel supply and delivery system and place both supply and demand for the ultra-low sulfur fuel at risk, thereby seriously jeopardizing the success and viability of the proposal. NATSO further added that the proposed rule requiring 30 ppm sulfur levels in 2004 could seriously disrupt the travel plaza and truck stop industry's ability to consistently and reliably acquire highway diesel fuel for retail sales and would place those diesel retailers in the covered areas under the 2004 proposal at a significant competitive disadvantage when compared to those diesel retailers in other area of Texas and neighboring states not covered by the proposal by requiring them to sell a fuel that would be almost impossible to acquire. NATSO commented that the proposed 30 ppm sulfur diesel required in 2004 would need to be segregated from the 500 ppm fuel throughout the state's distribution chain to prevent cross contamination and the added costs to segregate these fuels would further drive up fuel prices. Valero commented that the logistics of distributing "boutique" fuels ahead of the federal regulations to the eastern half of Texas is a practical impossibility. CITGO commented that refiners that supply both the Texas market and the Colonial/Explorer pipeline systems will have to have separate tanks to store the ultra-low diesel required in the Texas market in 2004 from the federal diesel being supply to the rest of the nation and that the tankage does not exist today to support an additional grade of diesel fuel that will only serve the Texas market. CITGO further added that the current tankage and logistics systems in refiners were not designed to protect product qualities down to the significantly ultra-low sulfur levels being proposed, especially when higher sulfur products are being handled in the same system. CITGO, Phillips 66, and TxOGA commented that a study conducted by the National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels,* June 2000, concluded that there was a doubt on whether the distribution system can handle ultra-low sulfur product and maintain the integrity of the sulfur level as long as higher sulfur products are being shipped in the same system. TMTA commented that the proposed rule will fragment the diesel fuel supply by requiring multiple types of diesel fuel within the state: a Western, an Eastern/Central, and a Houston/Galveston diesel, and this fragmentation will strain the state's diesel production and distribution system, leading to supply shortages and exorbitant prices. BCCA commented that the proposed LED rule will create an additional grade of diesel to be blended and distributed through systems that are already stretched beyond design and that there are serious and real concerns that it will not be possible to blend and distribute the boutique fuels throughout Texas while providing the rest of the country with EPA-specified fuels.

The commission acknowledges that the distribution system may have difficulties in segregating ultra-low sulfur diesel from other higher sulfur products. However, the commission believes that these issues can be overcome, as was shown by the industry's previous experiences with reformulated gasoline and low sulfur highway diesel fuel. The commission is confident that the industry will be able to provide compliant fuel in sufficient quantities to supply the Texas market and do so in a timely fashion to prevent major supply disruptions. The commission revised the rule to delete the proposed requirements which would have required 30 ppm sulfur by May 1, 2004 in order to provide greater flexibility for producers to comply with these rules and to be consistent with anticipated federal rulemaking and implementation schedules.

NATSO also commented that the proposed rule requiring 30 ppm in 2004 would essentially prohibit influx of foreign supplies of diesel fuel, which could otherwise be used to ease shortages in domestic production and supply, since the highway diesel fuel required in the covered areas would have a lower sulfur level than highway diesel produced in most other countries.

The commission revised the rule to delete the proposed requirements which would have required 30 ppm sulfur by May 1, 2004 in order to provide greater flexibility for producers to comply with these rules and to be consistent with anticipated federal rulemaking and implementation schedules.

Ato Fina and BCCA commented that the proposed implementation schedule does not allow sufficient time for the refining industry design, engineer, permit, procure equipment, construct, and begin production of the new fuel. ExxonMobil, Koch, NPRA, and UDS commented that the implementation schedule is unrealistic since refinery and infrastructure changes are not only costly but time consuming and it is not realistic to stipulate that major fuel property changes occur slightly more than a year after promulgation of regulations. Koch further added that a minimum of four years lead time is necessary in the best of times to plan, engineer, permit, construct, and test the additional diesel refining units needed to comply with the proposed fuel standard and that the unprecedented changes in gasoline properties that have been promulgated by the EPA as well as other voluntary actions that have been adopted by various refiners has extended engineering design and construction as never before and the time schedule for any other requirements can be expected to be longer than usual because of the enormous demand on finite resources. CITGO and NPRA commented that implementing new diesel fuel sulfur standards in 2002, 2004, and 2006 will certainly exceed the capacity of the industry's engineering and construction resources. CITGO, NPRA, and UDS commented that the proposed implementation date of May 1, 2002 does not allow adequate lead time for refiners to build the facilities needed to comply with the LED specifications and that the commission should not implement a diesel fuel standard that will require engineering and construction schedules for diesel desulfurization facilities to overlap with those of refinery facilities that will be built to meet the federal Tier II and other gasoline requirements. CITGO further added that overlapping the schedules for the federal and state gasoline and diesel fuel projects will increase the costs of both programs, as these projects will compete for the same scarce resources and both projects will be competing for permit approvals from state agencies, which are unlikely to have the resources to expedite the approvals even if they wished to do so. NPRA commented that the 30 and 15 ppm sulfur caps proposal exacerbates the competition for scarce construction and engineered equipment resources and that the commission should take these concerns into account and develop a more rational schedule for fuel specification changes. Valero recommended that the proposed rules be harmonized with the federal rules to prevent supply disruptions in Texas. ExxonMobil recommended that the commission use the maximum implementation schedule allowed by federal law and EPA policy as an alternative to the 2004 schedule and allow the installation of controls up until the HGA ozone attainment year of 2007 to alleviate much of the projected labor, material, and equipement shortfall and reduce the number of unscheduled shutdowns.

The commission acknowledges that the implementation schedule may be difficult for some producers to comply with if major refinery modifications are required. However, the 2002 implementation date does not require any further reductions in sulfur than required by current federal regulations and the rules allow the producer to use an approved alternative diesel fuel formulation if it is equivalent in emission reduction benefits to fuel meeting the rules' aromatic and cetane standards. The commission acknowledges that refinery modification will be required to comply with the 2006 sulfur standards and made all permit requests regarding facilities modifications or new construction to comply with the LED rules or the EPA Tier II low sulfur gasoline regulations top priority within the commission permitting process. The commission anticipates these types of permits will be processed within nine months of receipt, if uncontested. The commission believes that the industry is already planning refinery changes to meet both the EPA Tier II low sulfur gasoline and the proposed federal ultra-low sulfur diesel rules and should be able to complete these projects within the frame work of the rules' implementation schedule.

TMTA requested that the commission provide the public with the substantive materials that were used to develop the proposed rule and that the materials used to determine the feasibility and cost of distributing, storing, and retailing this stew of diesel fuels should also be provided to the public so that the industry can determine how the commission expects the Texas distribution system to respond when shortages or strong demand tax the fuel supply in different parts of the state.

The commission believes that sufficient fiscal impact information was provided in the fiscal note section of the rule proposal preamble. The commission believes that the current diesel fuel distribution system is adequate to handle the requirements of the rules and does not anticipate major supply shortages as a result of these rules. The commission is confident that the petroleum industry will be able to provide compliant fuel in sufficient quantities to supply the Texas market and do so in a timely fashion to prevent major supply disruptions. The commission has made no change to the rule language in response to these comments.

MECA expressed support for the proposed rules and commented that the availability of diesel fuel with very low sulfur levels is critical in maximizing the effectiveness of exhaust PM control technologies on the widest range of engines and that the proposed 30 ppm cap followed by the 15 ppm cap on diesel fuel for both non-road and on-road engines will greatly facilitate the utilization and optimization of the full range of control technologies for maximum control efficiency and will insure reliable and durable operation.

The commission appreciates the support. However, the commission revised the rule to delete the proposed requirements which would have required 30 ppm sulfur by May 1, 2004 in order to provide greater flexibility for producers to comply with these rules and to be consistent with anticipated federal rulemaking and implementation schedules.

Valero commented that it has no plans to upgrade its Texas refineries ahead of the federal rules to produce "boutique" fuels and will be forced to participate in the Texas market only as economics dictate. CITGO and ExxonMobil expressed concern that Texas refiners who are unable or unwilling to make the significant investments to address cetane and aromatics will find alternate deposition for the diesel volume they currently supply to Texas and that product availability will diminish significantly, creating fuel supply disruptions and dramatic price increases. UDS commented that Texas refineries currently export a large portion of their diesel outside of Texas and thus, have an alternative to supplying a boutique fuel to Texas markets.

The commission acknowledges that some producers may make the decision not to compete in the Texas market based on their inability or unwillingness to comply with the requirements of the rules. However, the commission is confident that the market will be supplied by existing producers that do make the investment to supply the market and by producers that may not have entered the Texas market in the past.

Koch and NATSO commented that the investment costs are underestimated and that fuel prices are estimated to be at least two to three times more than the commission's estimates. Metro commented that the estimated increase cost of $.08 per gallon is too optimistic and it is more likely that the cost of diesel fuel will increase in more severe increments and with higher frequency than considered in the proposed rule. AAR, ASLRRA, and Union Pacific commented that the commission significantly underestimated the effect this proposed rule will have on fuel prices because the infrastructure to produce and distribute diesel fuel meeting the proposed specifications is not in place in Texas, there have been no analysis of whether the prices that railroads and other ultimate purchasers of diesel fuel would pay for this special diesel and the price comparisons commensurate with increased production costs, and the price comparisons fail to consider actual differences in fuel prices or the recent spikes in fuel prices. CITGO commented that their experiences with producing maximum 15 ppm LED fuel has shown that the more frequent catalyst replacement needed to maintain the 15 ppm sulfur cap raises the cost of production by about $.07 per gallon, excluding capital recovery, and if CITGO is required to decrease aromatics and/or raise the cetane levels, the investment and operation costs will increase even more. TABCC commented that the proposed fuel is estimated to cost consumers and businesses $.12 to $.14 more per gallon and will be subject to price spikes like those observed in the Chicago area this past summer. NPRA commented that the cost of the first phase of the proposal may be understated since California diesel, which is similar to the proposed LED, has maintained a retail price difference much higher than the $.04 per gallon estimated by the commission. BCCA commented that the production cost of the proposed LED fuel in 2002 to be in the same league as CARB diesel, or about $.09 per gallon, based on the CARB diesel market place experience, since the two fuel specifications are similar. BCCA further added that the production cost to go from the 500 ppm sulfur level in the proposed LED in 2002 to the 15 ppm sulfur LED proposed for 2006 will be comparable to the cost to produce the proposed federal ultra-low sulfur diesel (15 ppm sulfur), or about $.10 per gallon, and therefore, unless there is a desulfurization technology breakthrough, or new refining process synergies developed, the combined cost for the proposed LED program in 2006 is estimated to be over two times higher than the commission estimate of $.08 per gallon. Five individuals commented that ultra clean fuels will carry high prices. PCCA commented that from the standpoint of cost to produce, benefits derived versus the increased costs to make the fuel makes the proposed requirements cost-prohibitive and worthy of reconsideration by the commission. ExxonMobil commented that the commission not provided valid and adequate cost estimates and economic impact analyses for the proposed 2004 implementation schedule.

According to a CARB publication entitled, *California Diesel Fuel Factsheet,* published in March 1997, a gallon of California diesel fuel costs approximately $.01 to $.04 more to produce than diesel fuel in other states. While other factors beside production costs can and do affect the retail prices of diesel fuel in California, the commission contends that production costs are the most stable measure for comparison analysis. A recent report published by the California Attorney General's Office entitled, *Preliminary Report to the Attorney General Regarding California Gasoline Prices,* dated November 22, 1999, stated that differences between fuel prices in California and most of the rest of the states can be attributed to a relative lack of competition within the California refining and marketing structure, California's unique fuel specifications and the distances from major refining centers and potential supply sources outside the state, and somewhat higher state taxes.

A comparison of the weekly average retail prices for on-highway diesel fuel published by the DOE for the week ending October 16, 2000 showed retail prices of California diesel to be $.16 more expensive than the retail prices of diesel fuel sold in the Gulf Coast region and $.10 more expensive than the national average. However, the commission contends that the $.04 increase in production costs is a valid determination of the costs associated with the proposed rules since other factors which could affect retail prices, as indicated above, are not the same in Texas as those in California.

The commission agrees with the comments that the actual retail price could be more expensive than just the difference in production costs. However, the commission is not aware of any firm method of determining what the actual retail price of LED fuel will be in May 2002 or in June 2006 and what factors will be affecting the price difference to that of conventional diesel fuel. In addition, the commission believes that new refining technologies for reducing sulfur, such as the recently introduced Phillips 66 "S Zorb" technology and BP's OATS process, could significantly reduce production costs and could help alleviate concerns over supply availability. The commission revised the rule to delete the proposed requirements which would have required 30 ppm sulfur by May 1, 2004 in order to provide greater flexibility for producers to comply with these rules and to be consistent with anticipated federal rulemaking and implementation schedules.

BCCA commented that based on learning from the CARB diesel experience and recent estimates made by the EPA and Charles Rivers Associates for very low sulfur diesel, it is estimated that the capital cost for statewide 2002 LED will be $500 million.

The commission acknowledges that significant capital costs could be incurred by some producers to meet the requirements of the rules and that the $500 million state-wide capital costs estimated by the commenter is comparable to the calculations estimated by the EPA. According to the EPA analysis found in the *Notice of Proposed Rulemaking on the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements,* the estimated capital costs for a typical refinery will be approximately $31 million.

TDA commented that the commission should consider the financial impact of the proposed rule on agriculture producers and that TDA would not like to see more government regulations placed on this industry if they are not necessary. BCCA commented that the commission has not considered the cost of the proposed rule on operators of non-road diesel equipment.

As noted in the rule proposal preamble, the fiscal analysis only considered on-road diesel vehicles because vehicle counts for non-road diesel vehicles were not available. However, the commission believes that costs will be similar for both on-road and non-road diesel vehicle users. The commission made no change to the rule language in response to these comments.

UDS commented that many formulations covering the production of California specification diesel are either patented or proprietary and therefore the cost to produce this fuel by non-California refiners may be even higher than in California itself.

The commission acknowledges that there may be issues with some producers over patent infringement. However, the rules allow the use of California-certified diesel fuel formulations as an option for compliance flexibility, not as a requirement. The rules do not prohibit diesel fuel producers from submitting their own diesel fuel formulations to California for certification and possibly preventing any patent infringement issues. The commission is unable to adequately address the issue of cost in this comment because the commenter did not provide any estimates toward the possible cost of patent infringement issues. The commission made no change to the rule language in response to this comment.

The Houston MPO commented that the commission should re-examine the NO_x benefit of the proposed rule because the commission's calculation of the NO_x benefit for the effect of using LED for on- and non-road vehicles produces less NO_x reductions than those calculated by the CARB.

The commission is aware that CARB claims a higher potential emission reduction (about 12%) for electronically-controlled diesel engines, using an equivalent fuel specification. However, this estimate is based on limited testing of a single engine from the early 1990's, using a simple fuel test matrix. The commission's estimate of NO_x benefits for the proposed rules is based on extensive testing under the EPA Heavy-Duty Engine Work Group (HDEWG), utilizing a sophisticated fuel matrix and a late-technology engine using exhaust gas recirculation, representative of engines meeting the upcoming 2004 standards. In addition, the 5.7% benefit estimate is more in line with other recent findings for similar fuels, including a 4.1% value obtained for 1998-equivalent engines under the European Auto-Oil study in 1999. Therefore, the commission believes the 5.7% value to be reasonable, and representative of those late model, electronically-controlled engines having the greatest emissions impacts in 2007. The commission made no changes to the rule language in response to this comment.

NPRA commented that the commission's estimate of 30 tpd of NO_x reduction in 2007 is too high and is a overstatement of the benefits in Texas that can be realized by changing diesel fuel formulation and that changing diesel fuel specifications without adding yet-to-be-commercialized retrofit pollution control to existing vehicles results in limited NO_x emission reductions from the existing fleet of heavy-duty trucks and buses.

The commission disagrees with this comment. The EPA proposed 2007 heavy-duty diesel engines standards will require engine manufacturers to utilize advanced emission control systems to achieve the standards and these systems will require the use of an ultra-low sulfur diesel fuel to be effective. The modeling associated with these rules used the estimated emission reductions from 2004 model heavy-duty engines using low sulfur diesel to estimate the claimed emission reductions for existing diesel engines. The commission made no change to the rule language in response to this comment.

UDS commented that emission benefits from boutique fuels may be overstated since some diesel vehicles that are not centrally fueled and have sufficient fuel capacity range will choose to purchase diesel outside of Texas, not only in Louisiana, New Mexico, and Oklahoma, but also Mexico, especially if the price differential between the EPA diesel and the proposed Texas LED is substantial. TMTA requested the commission to expand its analysis to more thoroughly address how freight contracts will shift to out-of-state companies offering cheaper rates using cheaper non-compliant diesel fuel and how this will reduce the rule's effectiveness. TMTA commented that given the proximity of the state's nonattainment areas to adjacent state borders, any state diesel fuel requirement can and will be avoided due to the higher cost of compliant fuel and that this will lead to a proliferation of out-of-state trucking companies serving the state.

The commission acknowledges that the possibility of out-of-state refueling by diesel truck traffic does exist. The commission is not aware of any estimates of the fraction of vehicle miles traveled (VMT) attributable to such "pass through" truck traffic. Therefore, without additional information, the commission is not able to estimate a reasonable offset factor for this effect. However, the rules apply to all diesel sales for on-road use statewide and the commission does not anticipate the impact of out-of-state refueling will be significant. Nevertheless, the intent of the rules is to impact as large a fraction of area-wide diesel VMT as is reasonable, which the commission believes will be accomplished through these rules. The commission made no change to the rule language in response to these comments.

BCCA, Koch, and TxOGA commented that the emission benefits of the proposal are overestimated because the two prediction models, the HDEWG model for post 1990 engines and the CARB model for earlier engines, used by ERG to predict emission benefits are extremely limited in scope and focus exclusively on advanced technology engines meeting the 2004 and later emission standards. Koch and TxOGA further added that the HDEWG study utilized large amounts of cetane improver in the diesel used to conduct the study and that most diesel fuel used in the HGA area does not contain cetane enhancers. Koch and TxOGA commented that the commission should consider the conclusions drawn in the Society of Automotive Engineers (SAE) Paper 982649, *Fuel Quality Impact on Heavy Duty Diesel Emission: A Literature Review,* in determining the benefits associated with the proposal.

The commission believes that while the uncertainty of the estimates from mechanically-controlled diesel engines provided by the ERG study, which was based on a small CARB data set operating on California diesel, is greater than the uncertainty of the estimates for newer, electronically-controlled engines, the claimed reductions are indeed reasonable and conservative. The 7.0% NO_x emission reduction value is only slightly higher than the 5.7% figure used for electronically-controlled engines in this analysis. Also, the mechanically-controlled engines make up less than 2.0% of the on-road VMT by 2007, based on local registration distributions and MOBILE5 default mileage accumulation rates. Therefore, for the on-road sector the impact of any uncertainty in these figures is diminished by the small size of the fleet under consideration.

In Phase I of the HDEWG testing, five to six fuel blends were sent to several different engine manufacturers, including Cummins and Detroit Diesel, for baseline testing. The EPA determined that the Caterpillar 3176 engine had emissions typical of equivalent technology engines from other manufacturers. These engines were selected to be representative of upcoming engines meeting 1998/2004 standards, according to the Southwest Research Institute (SwRI) program manager. Therefore, the Caterpillar 3176 engine was deemed an appropriate selection for further testing. This was the consensus among participating manufacturer representatives as well.

While it is true that the fuel set used in the HDEWG test program is atypical, the study could not have achieved its objective of determining parameter-specific effects without some sort of manipulations of the blends involved. In addition, SwRI technical staff involved in the test program point out that, by and large, the fuel set parameters were selected to mimic the fuel properties anticipated from advanced diesel fuel production in the near future. Finally, in regard to cetane enhancers, the test program clearly demonstrated that there was no significant difference in the interaction between natural or boosted cetane levels and other effects such as aromatics-induced reductions. Therefore, the pervasive presence of boosted cetane in the fuel matrix did not bias the outcome of the test program.

The SAE Paper 982649, which summarizes the available research up to that point on diesel fuel property impacts on emissions, cites a less than 5.0% impact for total aromatic reductions from 30% - 10% by weight. However, the authors of the paper themselves acknowledge that "on a percent basis, polyaromatics should contribute more to NO_x than a corresponding amount of mono-aromatics." Thus, if polyaromatics are reduced disproportionately compared to mono-aromatics, the reductions could be even greater than stated above. Since the HDEWG predictive model accounts for both poly- and mono-aromatic levels, the commission believes that the modeled result of 5.7% is within the range of reasonable reductions. In addition, the SAE authors themselves reference the ongoing work by the HDEWG as a source of future data concerning the differential effect of aromatic species. The commission made no change to the rule language in response to these comments.

Koch and TxOGA commented that the 2.5% emission reduction benefit claimed by the ERG study, and used by the commission to estimate the NO_x benefit of the proposed LED program, should be reduced to a 1.75% NO_x reduction benefit because the modeling in the ERG study assumed a typical alternative diesel formulation at 20% aromatics, compared to 10% aromatics required by the California diesel fuel standards. Information provided in the SAE Paper 982649 showed 2.5% to be a reasonable estimate only if aromatics were reduced from 30% - 10%.

The commission disagrees with this comment because all CARB certified alternative diesel formulations must demonstrate equivalent emissions performance to the base standard at 10% aromatics, and other parameters, such as cetane number, are usually raised to compensate for an increase in aromatics. Accordingly, the commission accounted for the modified parameters specified in the certified alternative diesel formulations, including relative contributions of poly- and mono-aromatics, in its modeling. Therefore, the fact that California diesel fuels were modeled by the commission at 20% aromatics levels to emulate the diesel fuel currently being used in California does not warrant the proposed correction factor. The 0% - 5.0% range cited in the SAE Paper 982649 may also be somewhat biased by the model year of the engines tested. Specifically, of approximately ten engines used to generate the 0% - 5.0% estimate, all but two were 1995 or older models (as old as 1991). Although more detailed research would be needed to quantify the effect, the commission believes that these engines most likely featured a higher pre-mix burn fraction than is found in the most advanced engines today, such as the Caterpillar 3176 engine tested by the HDEWG. This factor would tend to decrease the impact of aromatic reductions somewhat for the relatively older engines. The commission made no change to the rule language in response to this comment.

BCCA recommended that the commission remove the aromatic and cetane specifications associated with the proposed rule since these specifications are much less relevant when the new federal ultra-low sulfur diesel enters the market in 2006 followed by the low emission heavy-duty diesel engines in 2007. Ethyl commented that raising the minimum cetane number of diesel fuel in Texas to 50 would meet or exceed the emission reduction targets presented in the proposal and that no other fuel property changes, such as limiting aromatic hydrocarbons, are needed. Ethyl further added that this strategy is an inexpensive NO_x reduction proposal, that implementation is quick and easy, it requires no significant capital expense, it allows refiners flexibility in meeting the commission's target NO_x reductions, it will not disrupt supply since refiners can meet the cetane target through either refinery processing or readily available additives, the 50 cetane proposal can be accomplished within the commission's time frame, the new fuel can be easily monitored for compliance, and it would not require significant recordkeeping. UDS commented that replacing the proposed aromatics requirement with an increase in diesel cetane is the only realistic solution currently available to improve diesel quality and that this alternative would achieve the targeted NO_x reductions at a lower cost than requiring refinery modifications and could be implemented in accordance with the regulatory timetable without increased risk of supply disruptions.

The federal low-sulfur diesel proposal only generates significant NO_x reductions if used in conjunction with aftertreatment devices such as SCR. While such devices are anticipated in order to meet the proposed 2007 emission standards, there will be relatively little penetration of these engines into the fleet by calendar year

2007. Therefore, in order to generate the required NO_x reductions by this time, aromatics reductions (or equivalent formulations) are needed to affect the large portion of the on-road fleet unaffected by the 2007 standards.

The commission agrees that increasing cetane number appears to have a beneficial impact on NO_x emissions for current engine technologies. However, the HDEWG study is the best (and only) study to date evaluating fuel changes in 2004-compliant engines. This study found that cetane has a negligible effect on these engines. Considering the "pull-ahead" of the 2004 standards to the 2002 model year, and the disproportionately large contribution to total VMT from heavy-duty trucks six years of age and newer, 2004-compliant engines will have a very significant impact on on-road NO_x emissions in 2007. Therefore fuel specifications must affect this portion of the fleet as well as those engines meeting earlier standards. In order to achieve the required reductions, fuel strategies will most likely have to address both aromatics and cetane. While the commission is eager to evaluate additional studies involving 2004-compliant engines when they become available, judgements regarding fuel effects must be made given currently available information.

The commission agrees that manipulation of cetane number is likely to be less expensive than aromatics changes. However, the commission does not agree that cetane changes are the "only realistic solution" to the goal of NO_x reduction. The availability of low-aromatic diesel fuel in California and other markets clearly indicates that aromatic control is a realistic formulation strategy. In addition, the rules do allow alternative formulations of diesel fuel to be used, including diesel fuel with a higher cetane content than specified in the rules, as long as the emission reduction performance of the alternative formulation is equivalent to the specified LED fuel. The commission made no change to the rule language in response to these comments.

TxOGA commented that the proposed 10% aromatics limit may adversely affect the seals used within diesel engines resulting in possible seal failures and increased costs to the diesel engine user from otherwise unnecessary downtime and the substantial labor and materials involved in engine repairs. One individual commented that the commission should not implement the proposed rule if it will cause damage to diesel engines. One individual commented that the commission should make sure to adequately test new fuel formulas before imposing them on Houston to ensure against seal failures.

Investigation by the EPA and the CARB has shown that the reduced aromatic contents of low aromatic diesel fuels has contributed to fuel leaks in older diesel engines and vehicles, mainly from the shrinkage and possible cracking of the elastomeric seals, commonly known as O-rings, in some older diesel engines, but not in every case. The change from a higher to a lower aromatic fuel may cause elastomeric seals found in some older engines to shrink and possibly crack, especially those seals made of nitrile rubber that have seen long service at high temperatures. Commonly, the seals that failed were worn considerably and due for replacement. Thus, the cost for the worn seal or O-ring replacement would have to be incurred by the vehicle operator at some point, regardless of the change in fuel. The commission suggests that proper seal replacement and maintenance schedules will help prevent untimely equipment failures. Studies have shown that after the replacement of these seals, the occurrence of leaks was virtually eliminated.

In addition, the rules do allow alternative formulations of diesel fuel to be used, including diesel fuel with a higher aromatic content than specified in the rules, as long as the emission reduction performance of the alternative formulation is equivalent to the specified LED fuel. The commission made no change to the rule language in response to this comment.

Koch commented that the State of Texas seek any and all extensions to the attainment deadline that might be available under law to allow enough time for the federal fuel programs to deliver the emission reductions that are so critically needed by the HGA area. Koch further added that Texas should not be "forced" to adopt short-term stopgap measures that add enormous cost, and essentially inconsequential benefits.

The FCAA requires that a state have no more than one exceedance of the NAAQS in the year preceding the extension year, and that the state has complied with all requirements and commitments in the applicable implementation plan, prior to EPA granting such an extension. There is no provision in the FCAA or EPA guidance for EPA granting an extension in the absence of this data. However, the commission is committed to working with EPA and all interested parties to provide opportunities for new, low-emission equipment availability within the HGA nonattainment area.

The EPA commented that 42 USC, §7545(c)(4) preemption does not apply to fuel content for non-road diesel engines and therefore no waiver request is needed for the non-road portion of the proposed rule.

The commission agrees with the comment and has submitted its waiver request for the on-road portion of the rules only.

ARTBA, ExxonMobil, Koch, Lyondell-CITGO, Phillips 66, Union Pacific, and TxOGA commented that the commission failed to follow the requirements for adopting a major environmental rule as required by Texas Government Code, §2001.0225 (i.e. no cost benefit analysis performed; no draft impact analysis performed; no description of why identified reasonable alternative were rejected; and no final RIA performed). BCCA, CITGO, Lyondell-CITGO, Phillips 66, and REI commented that the proposed rule meets the definition of a major environmental rule and that the RIA requirements of Texas Government Code, §2001.0225 are triggered because the proposed rule exceeds standards set by federal law and exceeds an express requirement of state law. BCCA, REI, and Union Pacific further commented that the commission's efforts to avoid an RIA by asserting that the proposed rules are exempt from the RIA requirements because federal law mandates the rules is legally flawed and may render the rules invalid. UDS commented that the commission is required to perform a RIA since these proposals will require significant capitol investments by refiners.

The commission agrees with the commenters that the proposed rules meet the definition of a major environmental rule; however, the commission disagrees that its interpretation of the exemption for federally mandated standards is legally flawed. While the rules may require significant capital investments by refiners, that alone is not enough to trigger the RIA requirements. The Texas Government Code, §2001.0225 only applies to a major environmental rule adopted by a state agency, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

This rulemaking action does not meet any of these four applicability requirements, and is adopted in substantial compliance with the RIA requirements. Texas Government Code, §2001.035. These rules do not exceed an express standard set by federal law because the LED requirements are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. Title 42 USC, §7410 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 42 USC, §7410 does not specifically prescribe programs, methods, or reductions to meet the federal 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 42 USC, Chapter 85, Air Pollution Prevention and Control). The FCAA does require some specific measures for SIP purposes, such as an inspection and maintenance program, but those programs are the exception, not the rule, in the federal SIP structure. 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. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Failure to develop control strategies to demonstrate attainment can result in federal sanctions. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commissions photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to achieve reductions in ozone emissions in the HGA nonattainment areas. Specifically, as noted elsewhere in these rules preamble, the emission reductions associated with this rule are a necessary element of the attainment demonstration required by the FCAA.

This conclusion is supported by the legislative history for Texas Government Code, §2001.0225. During the 75th Legislative Session, SB 633 amended the Texas Government Code to require agencies to perform a RIA of certain rules. The intent of SB 633 was to require agencies to conduct a RIA of 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. 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. Because of the ongoing need to address nonattainment demonstrations required by federal law, the commission routinely proposes and adopts SIP rules. If each rule proposed for inclusion in the SIP was incorrectly considered as exceeding federal law, every SIP rule would require the full RIA contemplated by SB 633. This result would be inconsistent with the cost estimates and fiscal notes prepared by the commission and by the LBB. 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 meet the requirements under §2001.0225(a). 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. In other words, the proposed rules are intended to meet federal and state law, and do not go above and beyond what is required to meet federal or state statutes.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp,* 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue,* 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.,* 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert,* 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd,* Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor,* 24 S.W.3d 581 (Tex. App. - Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.,* 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the APA by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified §2001.0225 as falling under this standard. The commission substantially complied with the requirements of §2001.0225.

Therefore in addition to not exceeding an express standard set by federal law, these rules does not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, 382.017, 382.019, 382.037(g), and 382.039 authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

ExxonMobil and Union Pacific commented that the proposed rules were proposed without adequate notice as required by Texas Government Code, §2002.024. The commenters stated that Texas Government Code, §2001.024, requires adequate notice of a proposed rule, including information about its public benefits and costs. The commenters stated that adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule, and that courts have considered notice "adequate" only if: interested persons can confront the agency's factual suppositions and policy preconceptions; and the agency provides interested parties the opportunity to challenge the underlying factual data relied upon by the agency. The commenters asserted that the proposal included insufficient information and analysis regarding costs and impacts. The commenters asserted that in proposing the rules, the commission failed to provide interested parties with sufficient information to constitute adequate notice.

The commenters stated that it has identified a number of critical gaps in the underlying factual data, methodology, and analysis in support of the proposed rules. The commenters asserted that the commission has not adequately responded to requests for additional information from stakeholders. The commenters stated that the following requests for information were outstanding: information regarding the modeling of emissions; information regarding the corrected emissions inventory database; and information supporting the estimated costs of control. The commenters stated that this information is necessary in order to comment effectively on the proposed rules and that data gaps in the proposal hindered effective comment.

The commission disagrees with the commenters and made no change in response to these comments. Texas Government Code, §2001.024 requires of the notice of a proposed rule include certain information. Subsection (a)(5) requires that the notice state the public benefits expected as a result of the adoption of the proposed rule and the probable economic cost to persons required to comply with the rule. Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn,* 955 S.W.2d 649, 651 (Tex. App - Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of the proposed rules. The commission received intelligent comments which were substantial in both number and in scope, regarding the costs as well as the benefits. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the notice must include the cost of a reasonable method of compliance. Mere disagreement with cost estimates does not render notice inadequate.

The proposed rules meet the requirement to include sufficient information explaining the fuel concentration requirements, to whom they apply, the compliance schedule, the anticipated cost of compliance, and the anticipated reduction in emissions. To simply state that the proposal failed to provide sufficient information does not provide the commission with sufficient information to propose changes or alternative strategies. The commenters did not say how the notice is insufficient, merely that it is insufficient. Nevertheless, the commission reviewed the notice, determined it to be adequate, and responded to comments regarding costs associated with compliance with these rules elsewhere in this ANALYSIS OF TESTIMONY.

Similarly, the comments which state there are critical gaps did not identify what those gaps are or how that results in inadequate notice. The commission is unaware of any requests for additional information to which it was not completely responsive.

BCCA, ExxonMobil, Lyondell-CITGO, Phillips 66, REI, and Union Pacific commented that the commission proposed these rules without an adequate TIA as required by Texas Government Code, §2007 and that, although the commission asserted an exemption from performing a TIA based on the assertion that the proposal does not impose a greater burden than necessary to advance a health and safety propose and that the proposal "reasonably" fulfills federal mandates, the commission failed to provide the public a basis to infer that a cost/benefit analysis or a reasonableness determination was, in fact, performed as necessary to support the commission's exemption claim. The commenters stated that the TIA provision mandates that covered agencies "take a 'hard look' at the private real property implications of the actions they undertake . . . ," according to the Office of the Attorney General, *Private Real Property Rights Preservation Act Guidelines,* (21 TexReg 387, January 12, 1996). The commenters stated that under §2007.043, a TIA must describe the specific purpose of the proposed action, determine whether engaging in the proposed governmental action will constitute a taking, and describe reasonable alternative actions that could accomplish the specified purpose. The commenters stated that the agency must also explain whether these alternative actions also would constitute takings.

The commenters stated that agencies must also comply with guidelines developed by the Texas Attorney General when developing the TIA and that according to these guidelines, agencies must carefully review governmental actions that have a significant impact on the owner's economic interest. The commenters stated that these guidelines include the statement: "Although a reduction in property value alone may not be a 'taking,' a severe reduction in property value often indicates a reduction or elimination of reasonably profitable uses." (21 TexReg 392, January 12, 1996).

The commenters stated that the proposed rule preamble acknowledged that some of the rules may "burden" private real property, including these rules, but claimed an exemption from performing a TIA based on the assertion that the proposal does not impose a greater burden than necessary to advance a health and safety purpose and that the proposal "reasonably" fulfills a federal mandate. The commenters stated that the commission provided the public no basis to infer that a cost/benefit analysis or a reasonableness determination was, in fact, performed as necessary to support the TIA exemption claim because the preamble contains only the bare assertions. The commenters asserted that the proposed rules will impose a greater burden than is necessary, and are not reasonably taken to fulfill a federal mandate. The commenters believed that according to the Attorney General's Guidelines, a full TIA was required to be completed with the proposal, and that failure to perform a TIA could invalidate the rules.

As stated previously in the preamble, the purpose of the adopted rules is to ensure that LED is in place for all areas of the state in order to conform with the air quality standards established under federal law as NAAQS for ozone. The commission noted in the proposal that the rules may require the installation of control systems at refineries in some cases. The acknowledgment that the rules may require a capital investment or the installation of controls, is simply that, an acknowledgment. The commission understands that the rules may have an impact on real property and in noting this, sought comments on any potential impact to ensure that the adopted rules are technically and economically feasible. The commission believes that this acknowledgment has caused the commenters to misunderstand the commission's interpretation of the requirements of Texas Government Code, Chapter 2007. The commission does not believe that the assessment required by Chapter 2007 begins with a determination of whether or not the proposed rules could result in a capital investment. Rather, the commission believes that before an assessment is required, the commission must determine whether Chapter 2007 applies to the government action. If the proposed action is subject to an exception to Chapter 2007, the analysis is complete. Section 2007.003(b) provides that "this chapter does not apply to the following governmental actions. . . ." Because the commission believes the adopted rules meet the two exceptions to Chapter 2007, the full TIA is not required for the rules.

The commission believes the adopted rules are exempt under Texas Government Code, §2007.003(b)(4) because they are reasonably taken to fulfill an obligation mandated by federal law. While several governmental actions are subject to being reviewed under Chapter 2007, including the adoption of rules, §2007.003(b)(4) specifically excludes an action that is reasonably taken to fulfill an obligation mandated by federal law. The purpose of this rulemaking is to meet the air quality standards established under federal law as NAAQS.

The commission also believes that the adopted rules meet an additional exception to the requirements of Texas Government Code, Chapter 2007. First, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rule revisions 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 significantly advance the health and safety purpose. This action is taken in response to the HGA area exceeding the federal ambient air quality standard for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient VOC and ozone levels in HGA. Consequently, these rules meet the exemption in §2007.003(b)(13).

The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking therefore meets the requirements of Texas Government Code, §2007.003(b)(4) and (13). For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

BCCA, ExxonMobil, Lyondell-CITGO, Phillips 66, REI, and Union Pacific commented that the commission proposed these rules without an adequate small and micro-business assessment as required by Texas Government Code, §2006.002 and that it is not sufficient for the commission to merely state that the costs for small and large businesses with be the same or that the costs to small businesses cannot be determined, but that the commission is required to provide a cost comparison using an established standard to determine whether there is a disparate impact on small business. BCCA and REI further added that the commission did not publish the information mandated by Texas law and as a result, it is impossible for the public to comment on whether the commission adequately considered the effect of the proposed rules on small businesses.

The agency has estimated, to the extent possible, the costs to small businesses and has determined that the cost depends more upon the amount of diesel fuel consumed by the business and that it is not dependent upon the number of employees, hours of labor, or amount of sales income. Some small businesses use large amounts of diesel fuel while other use none. Large businesses vary in the same way. The commission provided the estimated cost per gallon of fuel and argues that this is the only meaningful way to provide sufficient notice of the cost to small business and therefore that it meets the objective of the Texas Government Code, Chapter 2006. This assertion is supported by the fact that no small businesses provided comments which include cost of compliance in terms of the number of employees, hours of labor, or amount of sales income.

BCCA, ExxonMobil, Lyondell-CITGO, Phillips 66, REI, and Union Pacific commented that the commission proposed these rules without a Local Employment Impact Statement as required by Texas Government Code, §2001.022 and that the commission failed to make the required initial determination, apparently ignoring that there is a great potential for the proposed rules to adversely affect the local economy.

The commission agrees with the commenters that the proposed rules may affect a local economy, however, does not agree that it is the responsibility of the commission to provide the local employment impact analysis. The APA requires state agencies to determine whether a rule may affect a local economy before proposing a rule for adoption. If the agency determines that a proposed rule may affect a local economy, the agency must send a copy of the proposed rule and other information to the Texas Workforce Commission (Workforce Commission) before the agency files notice of the proposed rule with the secretary of state. The APA requires the Workforce Commission to prepare a local employment impact statement for proposed rules, if a state agency requests the statement. The commission determined that the proposed rules might affect a local economy, and sent the proposed rules and other requested information to the Workforce Commission. The commission received a letter from the Workforce Commission, indicating that the Workforce Commission did not have the ability to determine the potential local employment impacts from the proposed rules.

BCCA, Koch, Lyondell-CITGO, REI, Phillips 66, and TxOGA commented that the proposed fuel rule is specifically prohibited by the Texas Health and Safety Code, §382.037(g) which prohibits state regulation of fuel content to a level more stringent than required by federal law unless a determination is made that a more stringent fuel-content rule is necessary to meet the ozone NAAQS. Phillips 66 and TxOGA further added that this prohibition would especially apply toward the attainment areas proposed to be affected by the proposal. BCCA and REI added that the commission therefore lacks the authority to require fuel controls in attainment areas. ExxonMobil commented that the commission must resolve several legal issues including the commission exceeding federal requirements without justification and the lack of financial and risk assessments as required by state law.

Texas Health and Safety Code, §382.037(g) authorizes the commission to regulate fuel content under certain circumstances, including the situtation where the regulation is necessary for the attainment of the federal ozone ambient air quality standards. In its request for a federal waiver from the EPA, the commission demonstrates that the rules are a necessary component of the SIP and that there are no other reasonable or practicable alternatives available. This demonstration applies statewide and also satisfies the condition of §382.037(g) that the rules are necessary to meet the NAAQS.

ExxonMobil commented that the commission has not provided valid and adequate scientific and technical analysis or justification, nor legal justification for the proposed 2004 implementation schedule, which exceeds federal requirements.

The commission revised the rule to delete the proposed requirements which would have required 30 ppm sulfur by May 1, 2004 in order to provide greater flexibility for producers to comply with these rules and to be consistent with anticipated federal rulemaking and implementation schedules.

Phillips 66 and TxOGA commented that the proposed rules violate FCCA, §211(c) which is a federal preemption of state regulation of fuel content to more stringent level than as regulated by the EPA unless a waiver has been applied for and approved in the SIP. Phillips 66 and TxOGA further added that the commission simply made conclusory statements about the need to control NO_x emissions on a regional basis and described how the commission's model determined the amount of NO_x reductions attributable to the proposed rules instead of evaluating all reasonable and feasible alternatives to the fuel-content rules. ExxonMobil commented that implementing the proposed rules statewide or regionally, solely to benefit the HGA nonattainment area counties, raises a number of federal preemption issues since there is no demonstration that these fuels are necessary to maintain air quality in attainment areas, especially when forthcoming federal fuel programs will be implemented throughout Texas and nationwide. Koch and UDS commented that the state may be preempted under the FCAA from adopting more stringent sulfur limits than the federal standards, especially in attainment counties.

The commission is approving simultaneously with these rules a SIP submittal which includes a FCAA, 211(c)(4)(C) waiver request and demonstration. This submittal includes all required components including a justification for the area of coverage. The commission is confident that the submittal meets the requirements for such a waiver and that the waiver will be approved by the EPA.

Baker Botts, BCCA, Dynegy, Dow, ExxonMobil, and Union Pacific commented that since EPA-regulated sources account for about 40% of the NO_x emissions in the affected areas, and that these sources are federally preempted and only the EPA, not the state, can effectively regulate them, the commission should incorporate an appropriate level of "federal assignments" into the proposal to restore it balance and to address the proposal's undue reliance on state-regulated sources. The commenters stated that the EPA issued a number of regulations for some federally preempted sources, such as land-based spark engines, marine, recreational and land-based diesel engines, aircraft and locomotive engines, well after the FCAA deadlines, and that the EPA recently strengthened rules for on-road and non-road vehicles and fuels, such as low sulfur gas and diesel, Tier II motor vehicles, heavy-duty highway vehicle standards, and non-road Tier II/Tier III heavy-duty engine standards. The commenters stated that delays in implementing these rules have prompted the commission to propose technically and economically infeasible emission reductions from sources in HGA that the state has authority to regulate to make up for the missing federal reductions. The commenters stated that these delays have forced the commission to propose expensive regional fuels and significant use restriction regulations. The commenters stated that the commission and the EPA can ensure an equitable distribution of the compliance burdens necessary to meet mandated air quality improvement in HGA only by allowing the SIP to capture anticipated emission reductions from federally preempted sources. Baker Botts noted that the EPA demonstrated a willingness to assume responsibility for a portion of emission reductions by creating a process in Los Angeles called a "public consultative process," that would resolve issues related to emissions from national and international sources, and that the EPA has also provided flexibility in obtaining offsets by allowing states to provide offsets to refiners based on emission reductions that the EPA projected would result from mobile sources using Tier II gasoline. Baker Botts suggested that this same sort of prospective crediting should be used to develop a more rational HGA SIP, and that the EPA should allow the commission to credit in the SIP the prospective emission reductions that will result from implementation of the Tier II gasoline rule and from other federally preempted sources. Finally, Baker Botts cited two cases wherein the District of Columbia Circuit has approved the EPA flexibility with respect to statutory deadlines under the FCAA when the EPA has failed to meets its own deadlines, and this failure was deemed to upset the balanced federal/state responsibilities under the FCAA. ExxonMobil commented that it supports the commission and the EPA crediting the HGA SIP with an additional 60 tpd of federally preempted emission reductions that will occur over the next ten years. Harris County commented that the commission should work with the EPA to accelerate the implementation schedule for federally preempted emissions so that at least one-half of the related emission reductions are achieved by 2007, and that as a part of this process, the commission should delineate federal assignments detailing the engine standards and emission reductions necessary to achieve real and sustainable pollution reductions.

The commission agrees with the commenters that emission reductions from federally preempted sources would provide benefits for the HGA SIP demonstration, and the inability of the commission to regulate certain source categories has necessitated the use of other ozone control strategies. However, the commission understands that the EPA SIP approval process does not provide a mechanism for credit for emission reductions that occur after the attainment date. The commission understands that the EPA is not currently considering accelerating implementation schedules for existing federal rules. The commission is working with the EPA to determine the availability of SIP credit for many non-traditional control strategy mechanisms, like economic incentive programs and flexibility for preempted source categories.

Additionally, the commission is working with the EPA to determine an appropriate federal contribution credit available for the HGA SIP.

Lyondell-CITGO, Phillips 66, and TxOGA commented that the proposed rules are being promulgated under improper rulemaking procedures due to the lack of a reasoned justification for the rules as required by Texas Government Code, §2001.033(a) and that the commission has not provided a reasonable justification for the application of the proposed rule in attainment areas. Phillips 66 and TxOGA further added that the FCAA evidences a clear congressional purpose to have nonattainment areas bear the economic burdens and sanctions of not being in compliance with NAAQS and that the commission is superceding this principle by seeking a regional solution to local nonattainment conditions. TMTA and Koch commented that the commission does not have the authority to require cleaner diesel fuel beyond the nonattainment area and requested that the commission identify the regulatory authority under which it is requiring cleaner diesel fuel in attainment counties.

The commission adopts these rules pursuant to authority TCAA, §§382.011, 382.012, 382.017, 382.019, 382.037(g), and 382.039. The underlying reason for adopting the rules is that they are necessary to achieve and to maintain attainment in the State of Texas especially in the nonattainment areas and the near nonattainment areas. The authority cited is not limited to nonattainment areas. As noted in the rule preamble, the commission expanded the rules to cover the entire state as a means to help alleviate concerns regarding out-of-area refueling practices in relation to the nonattainment counties and to reduce the regional transport of ozone precursors. Federal and state studies have shown that pollution from one area can affect ozone levels in another area. This work is supported by the findings of the OTAG study, which is the most comprehensive attempt ever undertaken to understand and quantify the transport of ozone. Both the commission and the OTAG study results point to the need to take a regional approach to control air pollutants, such as that prescribed in the rules. The state-wide implementation of LED fuel will help reduce the amount of NO_x being transported into the HGA, BPA, and DFW ozone nonattainment areas and other areas of the state having concerns over air quality. The state-wide coverage will also provide a greater market for diesel fuel producers and importers to provide the fuel required by these regulations. The commission and local area evaluated over 250 possible strategies while developing the attainment demonstration. These were identified in Appendix L of the SIP submittal. Modeling assessing the benefits of these rules demonstrated that by the year 2007, the use of LED will reduce NO_x emissions in the HGA ozone nonattainment area by 6.48 tpd, and statewide by 30 tpd.

The commission has demonstrated in the SIP that these rules are necessary to achieve the NAAQS. The commission disagrees with the comment that these rules circumvent the intent of Congress to limit the burden of non-compliance with the NAAQS to those areas specifically designated nonattainment. If Congress had intended SIP strategies to be implemented only in nonattainment areas it could have specified so in the FCAA. And if Congress intended a fuel waiver request only to be granted for implementation in nonattainment area it could have specified so in FCAA, §211(c)(4)(C). However, Congress used the broad language allowing waivers of federal preemption if the fuel strategy "is necessary to achieve the national primary or secondary ambient air quality standard which the plan implements." Congress did provide additional limitation to this waiver, although they do not limit the waiver as far as the commenters suggest. The additional limitation has to do with whether there are other reasonable and practicable measures which can be used instead. The commission has fulfilled all of the limitations which Congress placed on the waiver of federal preemption for fuel strategies and has demonstrated this in its SIP submittal. Therefore, the commission disagrees that this strategy circumvents the intent of Congress.

CBC, KIMI, Suderman, TWOA, and WTC commented that the commission lacks authority to regulate tug/towboat sources under the Commerce Clause of the United States Constitution and federal preemption of marine vessels as non-road mobile sources. TWOA further added that the commission lack authority under Texas Health and Safety Code, §382.019(a) to regulate marine vessels and engines since this regulation is specific to engines used to propel land vehicles.

The commission disagrees that the rules are preempted as regulations of non-road mobile sources. The commission points out that the regulated entities under these rules are the suppliers of diesel fuel, not the users. These rules do not require anything of tug/towboat sources. The commenter's interpretation of §209(e) would contradict the clear authority under §211(c)(4)(C) for states to adopt fuel regulations under certain circumstances. Therefore, these rules are not preempted as non-road engine standards.

The rules do not violate the Interstate Commerce Clause for a number of reasons. The rules do not impose different burdens on out-of-state entities, they do not impose any requirement on the equipment operator, either directly or indirectly, and they do not actually regulate what fuel may be used, only what fuel is available for sale. These rules will not require marine vessels to have different equipment to operate in Texas. The rules do not regulate the design, construction, alteration, repair, maintenance, operation, equipping, personnel qualification, and manning of marine vessels. The rules promulgated by the commission are specifically designed to attain a federal standard which applies equally in all states. Texas must comply with these limits like all states, and in so doing must choose which sources to regulate. The commission's actions do not place burdens on interstate commerce, they simply regulate local activities within the H/GA area, and thus do not violate the Commerce Clause of the United States Constitution.

Although the commission disagrees that there is any burden placed on interstate commerce by these rules and the corresponding SIP, any burdens that might be found are merely incidental and thus the regulations are allowable exercises of the state's police powers to promote health and safety. The United States Supreme Court has consistently held that the Commerce Clause is not an absolute bar to state regulation. "The limitation imposed by the Commerce Clause on state regulatory power is by no means absolute, and the states retain authority under their general police powers to regulate matters of legitimate local concern, even though interstate commerce may be affected." *Maine v. Taylor,* 477 U.S. 131, 138 (1986) *citing Lewis v. BT Investment Managers, Inc.,* 447 U.S. 27, 36 (1980). The Court has also consistently ruled that states may impose incidental burdens on interstate commerce, so long as the burdens are not "clearly excessive in relation to the putative local benefits." *Pike v. Church,* 397 U.S. 137 (1970). It has also been held that "{t}he protection of the environment and conservation of natural resources . . . are areas of legitimate local concern" justifying incidental burdens on interstate commerce. *New York*

State Trawler's Assoc. v. Jorling, 16 F.3d 1303, 1308 (2d Cir. 1994). The instant regulations and SIP will promote attainment of the ozone NAAQS in the HGA area, benefitting the health of hundreds of thousands of residents of that airshed. The minimal burdens, if any, imposed on interstate commerce clearly pale in comparison to these real gains in air quality.

Finally, Texas Health and Safety Code, §382.019 specifically authorizes rules to reduce emissions from engines used to propel land vehicles. Engines which use fuel subject to these rules are used, at least in part, to propel the equipment. The statute doesn't limit the commission's authority to control emissions from engines which are used solely or primarily to propel engines. Therefore the commission asserts that §382.019 does provide authority for the adoption of these rules. Additionally, the presence of this authorization does not imply a lack of authority to control emissions from other types of vehicles or equipment. For these reasons, the commission disagrees that this rulemaking exceeds its statutory authority.

KIMI, Suderman, and WTC commented that the commission proposed regulations that adversely affect their equipment while at the same time poses a direct threat to the safety of its operations and that the commissions should specifically exempt tug and tow boats from all proposed regulations because the proposed rules impose standards that unreasonably interfere with interstate commerce and impose an uniquely local standard in violation of the federal government's intent to regulate the maritime industry and under the Commerce Clause and require tug and tow boats to use unproven technology and fuel which could create a significant risk of substantial marine casualty and a threat of adverse impact to the environment and health and safety of the crew and surrounding population.

The control strategies being implemented by the commission in the HGA nonattainment area are necessary to the area's federal requirement to demonstrate attainment by 2007 and all possible reductions are needed. The commission believes that tug/tow boats are a contributing emission source in the HGA area and that it would not be appropriate to exclude them from these rules. As previously mentioned, the commission does not have any evidence to support the assertion that the LED fuel will adversely affect the commenters' equipment.

These rules do not directly apply to the user of the fuel but to the supplier. The rules simply regulate which fuel is available to those who purchase it in the state. Marine vessels which travel interstate are free to obtain fuel outside the state. For the reasons mentioned in a previous response, these rules do not violate the Interstate Commerce Clause. Additionally, these rules are not a regulation of the maritime industry.

ARTBA commented that the state is preempted under FCAA, §209(e) from adopting or attempting to enforce any standard or other requirement relating to the control of emissions from new farm or construction vehicles or engines under 176 hp or locomotives and as such the proposed fuel rules are not legally defensible.

The commission disagrees with the commenter's interpretation of FCAA, §209(e). This statutory provision is aimed at preventing manufacturing standards for new engines. See *Engine Manufacturers Association v. EPA,* 88 F.3d 1075, 1079 (D.C. Cir. 1996). Under the court's interpretation, only standards which apply to the non-road vehicles or engines are preempted by §209(e). States retain authority to promulgate in-use restrictions. Under this rule, no manufacturer will have to create a special vehicle for Texas which is what Congress intended to prohibit. The commenter's interpretation of §209(e) would contradict the clear authority under §211(c)(4)(C) for states to adopt fuel regulations under certain circumstances.

DoD commented that military equipment and fuel used to power the equipment should be exempted from these proposed rules under FCAA, §203(b)(1) and under the definition of motor vehicles specified in 40 CFR §85.1703 and under the exemption allowed in §85.1708 to exempt tactical wheeled vehicles from meeting the new 2007 emission standards.

DoD requested that the commission add a new subsection (c) to §114.317 which states as follows:

Equipment, which may otherwise be subject to this chapter, but used by any Department of Defense component, (including but not limited to the Departments of the Army, Navy, Air Force, any Reserve Component or National Guard Entity), and powered by a fuel in accordance with DoD mission requirements and directives shall not be subject to the requirements of this chapter.

The commission disagrees with this comment. The commission believes that this exemption is not needed as the definition for diesel fuel as specified in §114.6 precludes the fuel normally used by the DoD in its vehicles and engines, specifically JP-5 and JP-8. The commission made no change to the rule language in response to this comment.

Union Pacific expressed concern that the definition of "importer" could be read to include a railroad acting in its capacity as a common carrier of freight, i.e. merely hauling tank cars filled with diesel fuel into the HGA area while under hire by a separate entity, and requested that the commission provide a clarification in the rule that does not require common carriers to ensure that the fuel they haul meets the requirements of this rule. TPCA commented that transporters should not be considered "importers" because they have no control over the fuel they transport beyond moving the fuel from one destination to another at the behest of a supplier and that recordkeeping and reporting requirements should only be applied to those entities exercising control over the fuel's characteristics such as refiners manufacturing fuel for sale inside the state of Texas. TxOGA supported the proposed changes to the definitions of import and importer.

The commission agrees with this comment and made clarifications to the rule to exempt common carriers and transporters from the registration, reporting, and recordkeeping requirements by adding new definitions for transport and transporter and revising the definition of importer to exclude transporters acting in their capacity as common carriers.

TPCA recommended that the definition of "importer" be amended to apply to only those persons who import motor vehicle fuel into the affected counties listed in §114.319.

The rule requires diesel fuel to meet the LED requirement statewide in 2002 and as such the definition of importer must cover all persons who import fuel into the state. The commission made no change to the rule language in response to this comment.

Koch expressed concern that since the EPA made it clear that they consider ultra-low sulfur diesel fuel (in conjunction with advanced technology after-treatment) to be the only fuel reformulation approach that they consider cost effective or appropriate, the test protocol prescribed in 30 TAC §114.315(c) for alternative diesel formulation approval would be the only viable protocol acceptable by the EPA and therefore there would be no alternative to major refinery and infrastructure modification to comply with the proposed diesel fuel rule.

As noted in the rule preamble, the rules do allow the use of alternative formulations that provide the same emissions performance as the specified fuel content standards for aromatics and cetane. The commission believes that producers should be able to provide these alternative formulations in sufficient quantities in the near term to alleviate any concerns over the availability of supply for the 2002 implementation date. The alternative formulations may be produced through existing refining practices or through the use of additives as long as the emissions performance is equivalent to the specified fuel standards. As such, if alternative formulations are used, producers should be able to begin supplying diesel fuel compliant to the rules within the specified time frame. In addition, the commission believes that new refining technologies for reducing sulfur, such as the recently introduced Phillips 66 "S Zorb" technology and BP's OATS process, could significantly reduce production costs and could help alleviate concerns over supply availability. The EPA rulemaking regarding federal sulfur requirements does not imply that there are not areas of the nation that need more stringent controls. The commission submitted a request to the EPA for a waiver under FCAA, §211(c)(4)(C) which demonstrates the need for these rules. The commission believes that the waiver requirements have been met and anticipates that the EPA will approve the waiver. The commission made changes to the rules in response to these comments to include additional flexibility for approval of alternative diesel fuel formulations which are intended only for use in non-road equipment.

The EPA commented that §114.315(c) was not clear on whether alternative diesel fuel formulations would be approved with sulfur level greater than 30/15 ppm sulfur and if they are, these formulations could cause enforcement problems by contaminating supplies of compliant diesel fuel when mixed in retail storage tanks and therefore the proposed rule should require retailers and distributors to maintain all records relevant to fuel deliveries, including daily stick readings and meter readings to be maintained, and requiring stick readings before and after every fuel delivery to be maintained. The EPA commented that §114.315(c)(4) does not seem to require the applicant to show the effects of using a product that consists of commingled candidate fuel and referenced fuel and that this raises technical concerns about the effectiveness of alternative diesel fuel formulations, if not segregated from 30/15 ppm fuel at all parts of the distribution system.

The commission agrees that the rule proposal was not clear as to the commission's intent that all alternative diesel fuel formulations approved under §114.315(c) be required to meet the sulfur standards as specified in §114.312(b) and that the alternative formulations were only intended for compliance flexibility with the aromatic and cetane standards as specified in §114.312(c) and (d). The commission made clarifying changes to §114.312(g) to specify that the sulfur standard is not covered under the alternative formulation provisions of §114.315(c), only the aromatic and cetane standards.

The EPA commented that the proposed rules should require alternative diesel fuel formulations to be segregated from 30/15 ppm diesel in terminal storage tanks, as well as at retail level, in order to make the proposed rules enforceable. The EPA commented that the definitions of import facility and importer do not necessarily facilitate allowing the commission to track fuel from a refinery to a particular import facility without a requirement to designate and segregate every batch of fuel produced by each refinery, especially batches of alternative diesel fuel formulations with sulfur levels exceeding 30/15 ppm sulfur, and that without such a requirement the alternative diesel fuel formulation will be treated by pipelines and terminal as fungible 30/15 ppm product and commingled with LED from other refineries resulting in contamination of the compliance fuel with sulfur levels exceeding the sulfur standard.

The commission made changes to the rule language based on the previous comment that no longer allows the sulfur level of the alternative formulation to deviate from the specified sulfur standard. Therefore, both alternative formulations and compliance diesel fuel will be required to meet the same sulfur standard and there will be no need to segregate the alternative formulation from other compliance diesel within the distribution system.

The EPA commented that in 30 TAC §114.315(c) the commission should set upper and lower limits to all relevant specifications when approving alternative diesel fuel formulations, especially for sulfur content.

The commission disagrees with this comment. The rule allows the use of alternative formulations that provide the same emissions reduction performance as the specified LED fuel as flexibility for producers in complying with the aromatic and cetane standards. Upper and lower limits are not required for alternative formulations since all diesel must continue to meet the minimum requirements for federal diesel fuel in order to be used on-road in Texas. As mentioned previously, the alternative formulation provision has been clarified to specify that it does not cover sulfur content. The commission made no changes in response to this comment.

The EPA commented that the commission should clarify the definition for bulk plant which seems to include all terminals and asked whether this was intended.

The commission believes that the definition of bulk plant is clearly understood to include terminals and that it was the commission intent to include these facilities under these regulations. The commission made no change to the rule language in response to this comment.

The EPA commented that it does not understand the difference between the terms, "producer" and "refiner," and asked whether it is the intent to make "refiners" a subset of the term, "producer."

The commission agrees with this comment in that there seemed to be no difference in the coverage of the terms, "producer" and "refiner," in the rule proposal. The commission made changes in the rule language to remove the definitions for refiner and refinery and incorporate their meaning into the definitions of producer and production facility and also make clarifying changes through the rules to reflect these revisions.

The EPA commented that the language in §114.314 is confusing since the person who imports the fuel is not necessarily the same person who stores the fuel in a fixed storage facility and therefore the term, "its facility," as used in conjunction with the term, "importer," will frequently not apply.

The commission disagrees with this comment. The definition of import facility in §114.6 does not specify whether the import facility has to be owned or operated by the importer, only that it is where the importer takes delivery of the imported fuel and from which this fuel is transferred into the distribution system. Therefore, the language in §114.314 will always apply to the importer regardless of whether the importer is the same person that originally stored the fuel at that facility. The commission made no change to the rule language in response to this comment.

The EPA commented that the commission does not appear to have included a test method for sulfur in §114.315.

The test method for sulfur is specified in §114.315(a)(1) as adopted by the commission on April 19, 2000. The commission made no changes in the rule language in response to this comment.

SUBCHAPTER A. DEFINITIONS

30 TAC §114.6

STATUTORY AUTHORITY

The amendment is adopted under TWC, §5.103, which authorizes the commission to adopt rules necessary to carry out its powers and duties under the TWC; and under the Texas Health and Safety Code, TCAA, §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted under TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.019, which authorizes the commission to adopt rules to control and reduce emissions from engines used to propel land vehicles; §382.037(g), which authorizes the commission to regulate fuel content if it is demonstrated to be necessary for attainment of the NAAQS; and §382.039, which authorizes the commission to develop and implement transportation programs and other measures necessary to demonstrate attainment and protect the public from exposure to hazardous air contaminants from motor vehicles.

§114.6. Low Emission Fuel Definitions.

Unless specifically defined in the TCAA or in the rules of the commission, the terms used in this subchapter have the meanings commonly ascribed to them in the field of air pollution control. In addition to the terms which are defined by the TCAA, §3.2 of this title (relating to Definitions), and §101.1 of this title (relating to Definitions), the following words and terms, when used in Subchapter H of this chapter (relating to Low Emission Fuels), shall have the following meanings, unless the context clearly indicates otherwise.

(1) Additive - Any substance, other than one composed solely of carbon and/or hydrogen, that is intentionally added to gasoline or diesel fuel, including any added to a motor vehicle fuel system, and that is not intentionally removed prior to sale or use and that is approved by and registered with the EPA in accordance with 40 Code of Federal Regulations 79.

(2) Barrel - A unit of measure equal to 42 United States gallons.

(3) Bulk plant - An intermediate motor vehicle fuel distribution facility where delivery of motor vehicle fuel to and from the facility is solely by truck or pipeline.

(4) Bulk purchaser/consumer - A person who purchases or otherwise obtains motor vehicle fuel in bulk and then dispenses it into the fuel tanks of motor vehicles owned or operated by the person.

(5) Common carrier - A person engaged in the transportation of goods or products of another person for compensation and is available to the public for hire.

(6) Designated alternative limit (DAL) - An alternative specification limit for a specific fuel standard, which is assigned by a producer or importer to a final blend of low emission diesel fuel (LED) in accordance with §114.313 of this title (relating to Designated Alternative Limits).

(7) Diesel fuel - Any fuel that is commonly or commercially known, sold, or represented as diesel fuel Number 1-D or Number 2-D, in accordance with the American Society for Testing and Materials (ASTM) Test Method D975-98b (Standard Specification for Diesel Fuel Oils), dated 1998.

(8) Final blend - A distinct quantity of LED which is introduced into commerce without further alteration which would tend to affect a regulated LED specification of the fuel.

(9) Further process - To perform any activity on motor vehicle fuel, including distillation, treating with hydrogen, or blending, for the purpose of bringing the motor vehicle fuel into compliance with the requirements of Subchapter H of this chapter.

(10) Gasoline - Any fuel that is commonly or commercially known, sold, or represented as gasoline, in accordance with ASTM Test Method D4814-99 (Standard Specification for Automotive Spark-Ignition Engine Fuel), dated 1999.

(11) Import - The process by which motor vehicle fuel is transported into the State of Texas by any means or method whatsoever, including transport via pipeline, railway, truck, motor vehicle, barge, boat, or railway tank car.

(12) Import facility - The stationary motor vehicle fuel transfer point wherein the importer takes delivery of imported motor vehicle fuel and from which imported motor vehicle fuel is transferred into the cargo tank truck, pipeline, or other delivery vessel from which the fuel will be delivered to a bulk plant or retail fuel dispensing facility.

(13) Importer - Any person, except a person acting as a common carrier, who imports motor vehicle fuel.

(14) Low emission diesel (LED) - Any diesel fuel:

(A) sold, intended for sale, or made available for sale which may ultimately be used to power a diesel fueled compression-ignition engine in the counties listed in §114.319 of this title;

(B) that the producer knows, or reasonably should know, may ultimately be used to power a diesel fueled compression-ignition engine in counties listed in §114.319 of this title; and

(C) complies with the standards specified in §114.312 of this title (relating to Low Emission Diesel Standards).

(15) Motor vehicle - Any self-propelled device powered by a gasoline fueled spark-ignition engine or a diesel fueled compression-ignition engine in or by which a person or property is or may be transported, and is required to be registered under Texas Transportation Code (TTC), §502.002, excluding vehicles registered under TTC, §502.006(c).

(16) Motor vehicle fuel - Any gasoline or diesel fuel used to power gasoline fueled spark-ignition or diesel fueled compression-ignition engines.

(17) Non-road equipment - Any device powered by a gasoline fueled spark-ignition engine or a diesel fueled compression-ignition engine which is not required to be registered under TTC, §502.002.

(18) Produce - Perform the process to convert liquid compounds which are not motor vehicle fuel into motor vehicle fuel, except where a person supplies motor vehicle fuel to a producer who agrees in writing to further process the motor vehicle fuel at the production facility and to be treated as a producer of the motor vehicle fuel, only

the final producer shall be deemed for all purposes under Subchapter H of this chapter to be the producer of the motor vehicle fuel.

(19) Producer - Any person who owns, leases, operates, controls, or supervises a production facility and/or produces motor vehicle fuel.

(20) Production facility - A facility at which motor vehicle fuel is produced or that manufactures liquid fuels by distilling petroleum.

(21) Retail fuel dispensing outlet - Any establishment at which gasoline and/or diesel fuel is sold or offered for sale for use in motor vehicles, and the fuel is directly dispensed into the fuel tanks of the motor vehicles using the fuel.

(22) Supply - To provide or transfer fuel to a physically separate facility, vehicle, or transportation system.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009080
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

SUBCHAPTER H. LOW EMISSION FUELS
DIVISION 2. LOW EMISSION DIESEL

30 TAC §§114.312 - 114.317, 114.319

STATUTORY AUTHORITY

The amendments are adopted under TWC, §5.103, which authorizes the commission to adopt rules necessary to carry out its powers and duties under the TWC; and under the Texas Health and Safety Code, Texas Clean Air Act (TCAA), §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted under TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.019, which authorizes the commission to adopt rules to control and reduce emissions from engines used to propel land vehicles; §382.037(g), which authorizes the commission to regulate fuel content if it is demonstrated to be necessary for attainment of the NAAQS; and §382.039, which authorizes the commission to develop and implement transportation programs and other measures necessary to demonstrate attainment and protect the public from exposure to hazardous air contaminants from motor vehicles.

§114.312. Low Emission Diesel Standards.

(a) No person shall sell, offer for sale, supply, or offer for supply, dispense, transfer, allow the transfer, place, store, or hold any diesel fuel in any stationary tank, reservoir, or other container in the counties listed in §114.319 of this title (relating to Affected Counties and Compliance Dates), which may ultimately be used to power a diesel fueled compression-ignition engine in the affected counties, that does not meet either the low emission diesel (LED) standards of subsections (b) - (d) of this section, or the requirements of subsection (f) or (g) of this section.

(b) Sulfur content.

(1) The maximum sulfur content of LED shall not exceed 500 parts per million (ppm) by weight per gallon in the counties specified in §114.319(a) and (b) of this title.

(2) The maximum sulfur content of LED shall not exceed 15 ppm by weight per gallon in accordance with the counties and compliance date specified in §114.319(c) of this title.

(c) The maximum aromatic hydrocarbon content of LED is 10% by volume per gallon; or the LED has been reported in accordance with all of the requirements of §114.313 of this title (relating to Designated Alternative Limits), where:

(1) the aromatic hydrocarbon content does not exceed the designated alternative limit (DAL); and

(2) the designated alternative limit exceeds 10% by volume, the excess aromatic hydrocarbon content is fully offset in accordance with §114.313 of this title.

(d) The minimum cetane number for LED is 48.

(e) Subsection (a) of this section shall not apply to a sale, offer for sale, or supply of diesel fuel to a producer where the producer further processes the diesel fuel at the producer's production facility prior to any subsequent sale, offer for sale, or supply of the diesel fuel.

(f) Diesel fuel which has been produced to comply with all specifications for a Certified Diesel Fuel Formulation as approved by an executive order by the California Air Resources Board may be used to satisfy the requirements of subsection (a) of this section.

(g) Alternative diesel fuel formulations which the producer has demonstrated to the satisfaction of the executive director and the EPA, through emissions and performance testing methods prescribed in §114.315(c) and (d) of this title (relating to Approved Test Methods), as achieving comparable or better reductions in emissions of oxides of nitrogen, volatile organic compounds, and particulate matter may be used to satisfy the requirements of subsections (c) and (d) of this section. For alternative diesel fuel formulations that incorporate additive systems, the estimated emissions benefits of the alternative diesel fuel formulation may be determined by comparing the emissions and performance characteristics of the alternative diesel fuel with the additive system versus the emissions and performance characteristics of a diesel fuel without the additive system, as determined by the testing methods prescribed in §114.315(c) and (d) of this title. The commission recognizes that fuel content specifications, additive formulation, and testing technology often include factors that can reasonably be considered proprietary or confidential. Therefore, proprietary or confidential information supplied by the producer for evaluation of an alternative diesel fuel formulation must be identified as such when submitted. Decisions regarding confidentiality will be made subject to the Texas Public Information Act, Texas Government Code, Chapter 552.

§114.313. Designated Alternate Limits.

(a) A producer or importer may assign a designated alternative limit (DAL) for aromatic hydrocarbon content to a final blend of low emission diesel fuel (LED) produced or imported by the producer or importer, except for that LED produced in accordance with §114.312(g) of this title (relating to Low Emission Diesel Standards), if the following conditions are met.

(1) In no case shall the aromatic hydrocarbon content of the final blend shown by the sample and test conducted in accordance with §114.315 of this title (relating to Approved Test Methods) exceed the assigned DAL.

(2) The producer or importer shall notify the executive director of the volume (in barrels) and the DAL of the final blend. This notification shall be received by the executive director before the start of physical transfer of the LED from the production or import facility, and in no case less than 12 hours before the producer either completes physical transfer of the final blend.

(3) Within 90 days before or after the start of physical transfer of any final blend of LED to which a producer or importer has assigned a DAL exceeding the limit for aromatic hydrocarbon content specified in §114.312(c) of this title, the producer or importer shall complete physical transfer from the production or import facility of LED in sufficient quantity and with a DAL sufficiently below the standard specified in §114.312(c) of this title to offset the volume of aromatic hydrocarbons in the LED reported in excess of the standard.

(b) No person shall sell, offer for sale, or supply LED, in a final blend to which a producer or importer has assigned a DAL:

(1) exceeding the standard specified in §114.312(c) of this title for aromatic hydrocarbon content, where the total volume of the final blend sold, offered for sale, or supplied exceeds the volume reported to the executive director in accordance with subsection (a)(2) of this section; nor

(2) less than the standard specified in §114.312(c) of this title for aromatic hydrocarbon content, where the total volume of the final blend sold, offered for sale, or supplied is less than the volume reported to the executive director in accordance with subsection (a)(2) of this section.

(c) Whenever the final blend of a producer or importer includes volumes of diesel fuel the producer or importer has produced or imported, and volumes it has not produced or imported, the producer's or importer's DAL shall apply only to the volume of diesel fuel the producer or importer has produced or imported. In such a case, the producer or importer shall report to the executive director in accordance with subsection (a)(2) of this section, both the volume of diesel fuel produced or imported and the total volume of the final blend.

§114.315. Approved Test Methods.

(a) Compliance with the diesel fuel content requirements of §114.312 of this title (relating to Low Emission Diesel Standards) shall be determined by applying the following test methods and procedures, as appropriate.

(1) The sulfur content of low emission diesel (LED) shall be determined by the American Society for Testing and Materials (ASTM) Test Method D2622-98 (Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry), dated 1998.

(2) The aromatic hydrocarbon content of LED shall be determined by ASTM Test Method D5186-99 (Standard Test Method for Determination of Aromatic Content and Polynuclear Aromatic Content of Diesel Fuels and Aviation Turbine Fuels by Supercritical Fluid Chromatography), dated 1999.

(3) The cetane number of LED shall be determined by ASTM Test Method D613-95 (Standard Test Method for Cetane Number of Diesel Fuel Oil), dated 1995.

(4) The polycyclic aromatic hydrocarbon content of LED shall be determined by ASTM Test Method D2425-99 (Standard Test Method for Hydrocarbon Types in Middle Distillates by Mass Spectrometry), dated 1999.

(5) The nitrogen content of LED shall be determined by ASTM Test Method D4629-96 (Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection), dated 1996.

(6) The American Petroleum Institute (API) gravity index of LED shall be determined by ASTM Test Method D287-92 (Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)), dated 1995.

(7) The viscosity of LED shall be determined by ASTM Test Method D445-97 (Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (the Calculation of Dynamic Viscosity)), dated 1997.

(8) The flashpoint of LED shall be determined by ASTM Test Method D93-99c (Standard Test Methods for Flash-Point by Pensky-Martens Closed Cup Tester), dated 1999.

(9) The distillation temperatures of LED shall be determined by ASTM Test Method D86-00 (Standard Test Method for Distillation of Petroleum Products at Atmospheric Pressure), dated 2000.

(b) Alternatives to the test methods prescribed in subsection (a) of this section may be used if validated by Title 40 Code of Federal Regulations (CFR), Part 63, Appendix A (related to Test Methods), Method 301 (related to Field Validation of Pollutant Measurement Methods from Various Waste Media), dated December 29, 1992. For the purposes of this subsection, substitute "executive director" in each location that Test Method 301 references "administrator."

(c) The executive director, upon application of any producer or importer, may approve alternative diesel fuel formulations as prescribed under §114.312(g) of this title in accordance with the following procedures.

(1) The applicant shall initially submit a proposed test protocol to the executive director, which shall include:

(A) the identity of the entity which will conduct the tests described in paragraph (4) of this subsection;

(B) test procedures consistent with the requirements of paragraphs (2) and (4) of this subsection;

(C) test data showing that the candidate fuel meets the specifications for Number 1-D or 2-D diesel fuel as specified in ASTM D975-98b (Standard Specification for Diesel Fuel Oils), dated 1998, and identifying the characteristics of the candidate fuel identified in paragraph (2) of this subsection;

(D) test data showing that the fuel to be used as the reference fuel satisfies the specifications identified in paragraph (3) of this subsection;

(E) reasonable quality assurance and quality control procedures; and

(F) notification of any outlier identification and exclusion procedure that will be used, and a demonstration that any such procedure meets generally accepted statistical principles. The tests shall not be conducted until the protocol is approved by the executive director. Upon completion of the tests, the applicant may submit an application for certification to the executive director. The application shall include the approved test protocol, all of the test data, a copy of the complete test log prepared in accordance with paragraph (4)(D) of this subsection, a demonstration that the candidate fuel meets the requirements for certification specified in this subsection, and other information as the executive director may reasonably require. Upon review of the certification application, the executive director shall grant or deny the application. Any denial shall be accompanied by a written statement of the reasons for denial.

(2) The applicant shall supply the candidate fuel to be used in the comparative testing in accordance with paragraph (4) of this subsection.

(A) The sulfur content, total aromatic hydrocarbon content, polycyclic aromatic hydrocarbon, nitrogen content, and cetane number of the candidate fuel shall be determined as the average of three tests conducted in accordance with the referenced test method specified in subsection (a) of this section.

(B) The identity and concentration of each additive in the candidate fuel shall be determined by a test method specified by the applicant and approved by the executive director to adequately determine the presence and concentration of the additive.

(C) The applicant may also specify any other parameters for the candidate fuel, along with the test method for determining the parameters. The applicant shall provide the chemical composition of each additive in the candidate fuel, except that if the chemical composition of an additive is not known to either the applicant or to the manufacturer of the additive (if other), the applicant may provide a full disclosure of the chemical process of manufacture of the additive in lieu of its chemical composition.

(3) The reference fuel used in the comparative testing described in paragraph (4) of this subsection shall be produced from straight-run diesel fuel by a hydrodearomatization process and shall have the following characteristics determined in accordance with the referenced test method specified in subsection (a) of this section:

(A) sulfur content - as specified in §114.312(b) of this title;

(B) total aromatic hydrocarbon content - 10% maximum, volume percent;

(C) polycyclic aromatic hydrocarbon content - 1.4%, maximum weight percent;

(D) nitrogen content - ten parts per million, maximum;

(E) cetane number - 48, minimum;

(F) API gravity index - 33 to 39 degrees;

(G) viscosity at 40 degrees Celsius - 2.0 to 4.1 centistokes;

(H) flash point - 130 degrees Fahrenheit, minimum; and

(I) distillation:

(i) initial boiling point - 340 to 420 degrees Fahrenheit;

(ii) 10% point - 400 to 490 degrees Fahrenheit;

(iii) 50% point - 470 to 560 degrees Fahrenheit;

(iv) 90% point - 550 to 610 degrees Fahrenheit; and

(v) end point - 580 to 660 degrees Fahrenheit.

(4) Exhaust emission tests using the candidate fuel and the reference fuel specified in paragraph (3) of this subsection shall be conducted in accordance with the federal test procedures as specified in Title 40 CFR, Part 86 (Control of Emissions from New and in-Use Highway Vehicles and Engines), Subpart N (Emission Regulations for New Otto-Cycle and Diesel Heavy-Duty Engines - Gaseous and Particulate Exhaust Test Procedures), dated 1998.

(A) The tests shall be performed using a Detroit Diesel Corporation Series-60 engine or an engine specified by the applicant and approved by the executive director to be equally representative of the post-1990 model year heavy-duty diesel engine fleet.

(B) The comparative testing shall be conducted by a third-party or third-parties that are mutually agreed upon by the executive director and the applicant. The applicant shall be responsible for all costs of the comparative testing.

(C) The applicant shall conduct a minimum of five exhaust emission tests on the engine with each fuel, using either of the following sequences, where "R" is the reference fuel and "C" is the candidate fuel:

(i) RC, RC, RC, RC, RC (and continuing in the same order); or

(ii) RC, CR, RC, CR, RC (and continuing in the same order).

(D) The applicant shall submit a test schedule to the executive director at least one week prior to commencement of the tests. The test schedule shall identify the days on which the tests will be conducted, and shall provide for conducting the test consecutively without substantial interruptions other than those resulting from the normal hours of operations at the test facility. The executive director or his designee shall be permitted to observe any tests. The party conducting the testing shall maintain a test log which identifies all tests conducted, all engine mapping procedures, all physical modifications to or operational tests of the engine, all re-calibrations or other changes to the test instruments, and all interruptions between tests and the reason for each such interruption. The party conducting the tests or the applicant shall notify the executive director by telephone and in writing of any unscheduled interruption resulting in a test delay of 48 hours or more, and of the reason for such delay. Prior to restarting the test, the applicant or person conducting the tests shall provide the executive director with a revised schedule for the remaining tests. All tests conducted in accordance with the test schedule, other than any tests rejected in accordance with an outlier identification and exclusion procedure included in the approved test protocol, shall be included in the comparison of emissions in accordance with paragraph (5) of this subsection.

(E) In each test of a fuel, exhaust emissions of oxides of nitrogen (NO_x), volatile organic compounds (VOC), and particulate matter (PM) shall be measured.

(5) The average emissions during testing with the candidate fuel shall be compared to the average emissions during testing with the reference fuel specified in paragraph (3) of this subsection, applying one-sided Student's t statistics as set forth in Snedecar and Cochran, *Statistical Methods* (7th edition), page 91, Iowa State University Press, 1980. The executive director shall issue a certification in accordance with this paragraph only if he or she makes all of the following determinations:

(A) the average individual emissions of NO_x, VOC, and PM, respectively, during testing with the candidate fuel do not exceed the average individual emissions of NO_x, VOC, and PM, respectively, during testing with the reference fuel; and

(B) use of any additive identified in accordance with paragraph (2)(B) of this subsection in diesel powered engines will not increase emissions of noxious or toxic substances which would not be emitted by such engines operating without the additive.

(6) If the executive director finds that a candidate fuel has been properly tested in accordance with this subsection, and makes the determinations specified in paragraph (5) of this subsection, then the executive director shall issue an approval notification certifying that the alternative diesel fuel formulation represented by the candidate fuel may be used to satisfy the requirements of §114.312(a) of this title. The approval notification shall identify all of the characteristics of the candidate fuel determined in accordance with paragraph (2) of this subsection.

(A) The approval notification shall provide that the approved alternative diesel fuel formulation has the following specifications:

(i) a sulfur content, total aromatic hydrocarbon content, polycyclic aromatic hydrocarbon content, and nitrogen content not exceeding that of the candidate fuel;

(ii) a cetane number not less than that of the candidate fuel; and

(iii) presence of all additives that were contained in the candidate fuel, in a concentration not less than in the candidate fuel.

(B) All such characteristics shall be determined in accordance with the test methods identified in subsection (a) of this section. The approval notification shall assign an identification number to the specific approved alternative diesel fuel formulation.

(d) Notwithstanding subsection (c) of this section, the executive director, upon application of any producer or importer, may approve alternative diesel fuel formulations as prescribed under §114.312(g) of this title which may be used to satisfy the requirements of §114.312(c) and (d) of this title if the formulations are intended only for use in non-road equipment and, through emissions and performance testing with supporting data, the producer or importer has demonstrated to the satisfaction of the executive director and the EPA as achieving comparable or better reductions in emissions of NO_x, VOC, and PM.

§114.316. Monitoring, Recordkeeping, and Reporting Requirements.

(a) Every producer or importer that has elected to sell, offer for sale, supply, or offer for supply low emission diesel fuel (LED) in counties listed in §114.319 of this title (relating to Affected Counties and Compliance Dates) is subject to the requirements of this section. Under these requirements LED which has been produced or imported must conform with the standards for sulfur content, aromatic hydrocarbon content, and minimum cetane number as specified in §114.312 of this title (relating to Low Emission Diesel Standards) or other standards, including the type and concentration of additive as specified in accordance with §114.312(g) of this title. All records relating to LED must contain a statement declaring whether the aromatic hydrocarbon content of the sample conforms to the basic standard, to a designated alternative limit (DAL) in accordance with §114.313 of this title (relating to Designated Alternative Limits), to a limit specified in a Certified Diesel Fuel Formulation as approved by an executive order issued by the California Air Resources Board (CARB), or whether the diesel fuel conforms to an alternative diesel fuel formulation approved under §114.312(g) of this title.

(b) Each producer or importer of a diesel fuel that conforms to §114.312(a) - (f) of this title shall sample and test for the sulfur content, aromatic hydrocarbon content, and minimum cetane number in each final blend of LED which the producer or importer has produced or imported, by collecting and analyzing a representative sample of diesel fuel taken from the final blend, using the methodologies specified in §114.315 of this title (relating to Approved Test Methods). If a producer or importer blends diesel fuel components directly to pipelines, tank ships, railway tank cars, or trucks and trailers, the loading(s) shall be sampled and tested for the sulfur content, aromatic hydrocarbon content, and minimum cetane number by the producer or importer or authorized contractor. The producer or importer shall maintain, for two years from the date of each sampling, records showing the sample date, identity of blend sampled, container or other vessel sampled, final blend volume, and the sulfur content, aromatic hydrocarbon content, and minimum cetane number. All diesel fuel produced by the producer or imported by the importer and not tested as LED by the producer or importer as required by this section shall be deemed to exceed the standards specified in §114.312 of this title, unless the producer or importer demonstrates that the diesel fuel meets those standards and limits.

(c) Each producer or importer of a diesel fuel that conforms to §114.312(g) of this title shall sample and test for the appropriate components approved by the executive director in each final blend of LED which the producer or importer has produced or imported, by collecting and analyzing a representative sample of diesel fuel taken from the final blend, using the methodologies specified in §114.315 of this title. If a producer or importer blends diesel fuel components directly to pipelines, tank ships, railway tank cars, or trucks and trailers, the loading(s) shall be sampled and tested for the appropriate components approved by the executive director by the producer or importer or authorized contractor. If the approved blend contains an additive system, the producer or importer or authorized contractor shall maintain records showing that sufficient additive was added to maintain the appropriate additive concentration as approved by the executive director. The producer or importer shall maintain, for two years from the date of each sampling, records showing the sample date, identity of blend sampled, container or other vessel sampled, final blend volume, and the appropriate fuel components. All diesel fuel produced by the producer or imported by the importer and not tested as LED by the producer or importer as required by this section shall be deemed to exceed the standards specified in §114.312 of this title, unless the producer or importer demonstrates that the diesel fuel meets those standards and limits.

(d) A producer or importer shall provide to the executive director any records required to be maintained by the producer or importer in accordance with this section within five days of a written request from the executive director, if the request is received before expiration of the period during which the records are required to be maintained. Whenever a producer or importer fails to provide records regarding a final blend of LED in accordance with the requirements of this section, the final blend of diesel fuel shall be presumed to have been sold by the producer or importer in violation of the standards specified in §114.312 of this title, to which the producer or importer has elected to be subject.

(e) All parties in the distribution chain (producer, importer, terminals, pipelines, truckers, rail carriers, and retail fuel dispensing outlets) subject to the provisions of §114.312 of this title must maintain copies or records of product transfer documents for a minimum of two years and shall upon request, make such copies or records available to representatives of the commission, EPA, or local air pollution agency having jurisdiction in the area. The product transfer documents must contain, at a minimum, the following information:

(1) the date of transfer;

(2) the name and address of the transferor;

(3) the name and address of the transferee;

(4) in the case of transferors or transferees who are producers or importers, the registration number of those persons as assigned by the commission under §114.314 of this title (relating to Registration of Diesel Producers and Importers);

(5) the volume of diesel fuel being transferred;

(6) the location of the diesel fuel at the time of transfer;

(7) the following certification statement: "This product complies with the requirements for low emission diesel fuel specified in Title 30 Texas Administrative Code, §114.312 and may be used in any Texas county requiring the use of low emission diesel fuel in compression-ignition engines."; and

(8) in the case of diesel fuel that was produced under the requirements of §114.312(f) or (g) of this title, the executive order number as issued by the CARB or the approval notification number as issued by the executive director in accordance with §114.315(c)(6) or (d) of this title.

(f) For each final blend which is sold or supplied by a producer or importer from the party's production facility or import facility, and which contains volumes of diesel fuel that the party has produced and imported and volumes that the party neither produced nor imported, the producer or importer shall establish, maintain, and retain adequately organized records containing the following information.

(1) The volume of diesel fuel in the final blend that was not produced or imported by the producer or importer, the identity of the persons(s) from whom such diesel fuel was acquired, the date(s) on which it was acquired, and the invoice(s) representing the acquisition(s).

(2) The sulfur content, aromatic hydrocarbon content, and the cetane number of the volume of diesel in the final blend that was not produced or imported by the producer or importer, determined either by:

(A) sampling and testing by the producer or importer of the acquired diesel fuel represented in the final blend; or

(B) written results of sampling and test of the diesel fuel supplied by the person(s) from whom the diesel fuel was acquired.

(3) A producer or importer subject to subsection (f) of this section shall establish such records by the time the final blend triggering the requirements is sold or supplied from the production or import facility, and shall retain such records for two years from such date. During the period of required retention, the producer or importer shall make any of the records available to the executive director upon request.

(g) Each producer or importer electing to sell, offer for sale, supply, or offer to supply LED in accordance with §114.312 of this title shall provide a report on each final blend and a quarterly summation report to the executive director no later than the fifteenth of the month following the end of the calendar quarter. The report on each final blend shall provide, at a minimum, the information required to be collected by subsections (b), (c), and (f) of this section. The quarterly report shall provide, at a minimum, reconciliation of the quarter's transactions relative to the requirements of subsections (b), (c), and (f) of this section. Updates or revisions to estimated transaction volumes required by subsections (b) and (c) of this section shall be included in this report.

(h) Each producer or importer electing to sell, offer for sale, supply, or offer to supply LED under §114.312(f) of this title shall provide to the executive director a copy of the executive order issued by the CARB for the Certified Diesel Fuel Formulation used to produce the LED and shall comply with the requirements of subsections (b) and (f) of this section using the fuel specifications for aromatic hydrocarbon, sulfur, and cetane set by this executive order.

(i) Each producer or importer electing to sell, offer for sale, supply, or offer to supply LED under §114.312(f) of this title shall sample and test for the polycyclic aromatic hydrocarbon content and nitrogen content in each final blend of LED which the producer or importer has produced or imported using the fuel specifications for polycyclic aromatic hydrocarbons and nitrogen set by the executive order issued by the CARB for the Certified Diesel Fuel Formulation used to produce the LED, by collecting and analyzing a representative sample of diesel fuel taken from the final blend using the methodologies specified in §114.315 of this title and shall include a record of these tests in the report required by subsection (g) of this section.

§114.317. Exemptions to Low Emission Diesel Requirements.

(a) Any diesel fuel that is either in a research, development, or test status; or is sold to petroleum, automobile, engine, or component manufacturers for research, development, or test purposes; or any diesel fuel to be used by, or under the control of, petroleum, additive, automobile, engine, or component manufacturers for research, development, or test purposes, is exempted from the provisions of this division (relating to Low Emission Diesel), provided that:

(1) the diesel fuel is kept segregated from non-exempt product, and the person possessing the product maintains documentation identifying the product as research, development, or testing fuel, as applicable, and stating that it is to be used only for research, development, or testing purposes; and

(2) the diesel fuel is not sold, dispensed, or transferred, or offered for sale, dispensing, or transfer from a retail fuel dispensing facility. It shall also not be sold, dispensed, or transferred, or offered for sale, dispensing, or transfer from a wholesale purchaser-consumer facility, unless such facility is associated with fuel, automotive, or engine research, development or testing.

(b) Any diesel fuel that is refined, sold, dispensed, transferred, or offered for sale, dispensing, or transfer as competition racing fuel is exempted from the provisions of this division, provided that:

(1) the fuel is kept segregated from non-exempt fuel, and the party possessing the fuel for the purposes of refining, selling, dispensing, transferring, or offering for sale, dispensing, or transfer as competition racing fuel maintains documentation identifying the product as racing fuel, restricted for non-highway use in competition racing motor vehicles or engines;

(2) each pump stand at a regulated facility, from which the fuel is dispensed, is labeled with the applicable fuel identification and use restrictions described in paragraph (1) of this subsection; and

(3) the fuel is not sold, dispensed, transferred, or offered for sale, dispensing, or transfer for highway use in a motor vehicle.

(c) The owner or operator of a retail fuel dispensing outlet is exempt from all requirements of §114.316 of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements) except §114.316(e) of this title.

(d) Diesel fuel that does not meet the requirements of §114.312 of this title (relating to Low Emission Diesel Standards) is not prohibited from being transferred, placed, stored, and/or held within the affected counties so long as it is not ultimately used:

(1) to power a diesel fueled compression-ignition engine in a motor vehicle in the counties listed in §114.319 of this title, except for that used in conjunction with purposes stated in subsections (a) and (b) of this section; or

(2) to power a diesel fueled compression-ignition engine in non-road equipment in the counties listed in §114.319(b) of this title, except for that used in conjunction with purposes stated in subsections (a) and (b) of this section.

§114.319. Affected Counties and Compliance Dates.

(a) Beginning May 1, 2002, affected persons in all counties of Texas shall be in compliance, as applicable, with §§114.312 - 114.317 of this title (relating to Low Emission Diesel Standards; Designated Alternate Limits; Registration of Diesel Producers and Importers; Approved Test Methods; Monitoring, Recordkeeping, and Reporting Requirements; and Exemptions to Low Emission Diesel Requirements) for that diesel fuel which may ultimately be used to power a diesel fueled compression-ignition engine in a motor vehicle.

(b) Beginning May 1, 2002, affected persons in the following counties shall be in compliance with §§114.312 - 114.317 of this title for that diesel fuel which may ultimately be used to power a diesel fueled compression-ignition engine in a motor vehicle or in non-road equipment:

(1) Collin, Dallas, Denton, and Tarrant;

(2) Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller;

(3) Hardin, Jefferson, and Orange; and

(4) Anderson, Angelina, Aransas, Atascosa, Austin, Bastrop, Bee, Bell, Bexar, Bosque, Bowie, Brazos, Burleson, Caldwell, Calhoun, Camp, Cass, Cherokee, Colorado, Comal, Cooke, Coryell, De Witt, Delta, Ellis, Falls, Fannin, Fayette, Franklin, Freestone, Goliad, Gonzales, Grayson, Gregg, Grimes, Guadalupe, Harrison, Hays, Henderson, Hill, Hood, Hopkins, Houston, Hunt, Jackson, Jasper, Johnson, Karnes, Kaufman, Lamar, Lavaca, Lee, Leon, Limestone, Live Oak, Madison, Marion, Matagorda, McLennan, Milam, Morris, Nacogdoches, Navarro, Newton, Nueces, Panola, Parker, Polk, Rains, Red River, Refugio, Robertson, Rockwall, Rusk, Sabine, San Jacinto, San Patricio, San Augustine, Shelby, Smith, Somervell, Titus, Travis, Trinity, Tyler, Upshur, Van Zandt, Victoria, Walker, Washington, Wharton, Williamson, Wilson, Wise, and Wood.

(c) Beginning June 1, 2006, affected persons in the counties listed in subsection (b) of this section shall be in compliance with §114.312(b)(2) of this title for that diesel fuel which may ultimately be used to power a diesel fueled compression-ignition engine in a motor vehicle or in non-road equipment.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009081
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

CHAPTER 114. CONTROL OF AIR POLLUTION FROM MOTOR VEHICLES

SUBCHAPTER C. VEHICLE INSPECTION AND MAINTENANCE

30 TAC §§114.50-114.53

The Texas Natural Resource Conservation Commission (commission) adopts amendments to §114.50, Vehicle Emissions Inspection Requirements; §114.51, Equipment Evaluation Procedures for Vehicle Exhaust Gas Analyzers; §114.52, Waivers and Extensions for Inspection Requirements; and §114.53, Inspection and Maintenance Fees. The commission adopts these amendments to Chapter 114 (Control of Air Pollution from Motor Vehicles), and to the state implementation plan (SIP) in order to control ground-level ozone in the Houston/Galveston (HGA) ozone nonattainment area. These amendments are one element of the control strategy for the HGA Post-1999 Rate-of-Progress (ROP)/Attainment Demonstration SIP. Sections 114.50, 114.52, and 114.53 are adopted *with changes* to the text published in the August 25, 2000, issue of the *Texas Register* (25 TexReg 8180). Section 114.51 is adopted *without changes* and the text will not be republished.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

The HGA ozone nonattainment area is classified as Severe-17 under the Federal Clean Air Act (FCAA) Amendments of 1990 (42 United States Code (USC), §§7401 et seq.), and therefore is required to attain the one-hour ozone standard of 0.12 parts per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined by Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties, has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of its Post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base-case episodes, adopted rules to achieve a 9% rate-of-progress (ROP) reduction in volatile organic compounds (VOC), and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary nitrogen oxides (NO_x) waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base-case episodes which marginally exhibited model performance in accordance with the United States Environmental Protection Agency (EPA) modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data-gathering exercise known as the COAST study. The state believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, EPA policy regarding SIP elements and timelines went through changes. Two national programs in particular resulted in changing deadlines and requirements. The first of these programs was the Ozone Transport Assessment Group. This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for

Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in this study, and it has been concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that impacted the SIP planning process is the revision to the national ambient air quality standard (NAAQS) for ozone. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, EPA proposed an interim implementation plan (IIP) that it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development timelines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, that standard would continue to apply until it is attained. The FCAA requires that HGA attain the standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998, a revision to the HGA SIP which contained the following elements in response to the EPA guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by Subpart 2 of Title I of the FCAA to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the state eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs as well as an acceleration simulation mode (ASM-2) equivalent motor vehicle inspection and maintenance (I/M) program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory state-wide programs adopted or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon Scenario VIf); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review; and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-99 ROP plan by December 31, 2000; to perform a mid-course review by May 1, 2004; and to perform modeling of mobile source emissions using the EPA mobile source emissions model (MOBILE6), to revise the on-road mobile source budget as needed, and to submit the revised budget within 24 months of the model's release. In addition, if a conformity analysis is to be performed between 12 months and 24 months after the MOBILE6 release, the state will revise the motor vehicle emissions budget (MVEB) so that the conformity analysis and the SIP MVEB are calculated on the same basis.

In order for the state to have an approvable attainment demonstration, the EPA indicated that the state must adopt those strategies modeled in the November submittal and then adopt sufficient controls to close the remaining gap in NO_x emissions. The modeling and other analysis supporting these rules and the HGA SIP indicates a gap of approximately an additional 91 tons per day (tpd) of NO_x reductions is necessary for an approveable attainment demonstration. The predicted emission reductions from these rules are necessary to successfully demonstrate attainment.

The emission reduction requirements included as part of this SIP revision represent substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, have worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

This rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA

SIP are being adopted concurrently in this issue of the *Texas Register,* or were included in the HGA SIP considered by the commission on December 6, 2000 and planned to be submitted to EPA by December 31, 2000.

The amount of NO_x reductions required for the area to attain the ozone NAAQS has 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 reduction strategies. The FCAA, 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 oversight committee. Commission staff have continued to improve the air quality modeling technology and refine emission inventory data. Numerous emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources, on-road and non-road mobile sources, and area sources were analyzed in multiple iterations of modeling, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling and other analysis submitted for public hearing and comment concurrently with the HGA SIP show that a significant amount of NO_x reductions practicably achievable are necessary from ozone control strategies in order for the HGA nonattainment area to achieve the ozone NAAQS by 2007, including reductions from surrounding counties included in the HGA consolidated metropolitan statistical area (CMSA).

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies. At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The current SIP revision contains rules, enforceable commitments, photochemical modeling analyses, and calculation of the remaining NO_x reductions required to reach attainment (gap calculation) in support of the HGA ozone attainment demonstration. In addition, this SIP contains post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contains enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit a mid-course review.

The HGA ozone nonattainment area will need to ultimately reduce NO_x more than 750 tpd to reach attainment with the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of the I/M program will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area. An I/M program should also contribute to a successful demonstration of transportation conformity in the HGA area.

The commission is proposing an air control strategy for NO_x reductions which requires emissions testing of motor vehicles that are registered and primarily operated in the HGA ozone nonattainment area. The testing would use ASM-2 and on-board diagnostic (OBD) technologies. This adopted I/M program was modeled to cover the eight-county region comprising the HGA nonattainment area. The adopted I/M program will reduce NO_x emissions from on-road vehicles in the HGA ozone nonattainment area by 36.20 tpd.

The adopted revisions will modify the vehicle emissions testing program by implementing ASM-2 testing in the HGA ozone nonattainment area. Unlike the current two-speed idle (TSI) test, ASM-2 technology has the ability to detect NO_x emissions. Because NO_x is a precursor to ground-level ozone formation, reduced NO_x and VOC emissions will result in ground-level ozone reduction.

The amendments addressed in these rule changes include: changing the testing technology in the HGA area to ASM-2 and OBD for Harris County beginning May 1, 2002; implementing ASM-2 and OBD in Brazoria, Fort Bend, Galveston, and Montgomery Counties beginning May 1, 2003; implementing ASM-2 and OBD in Chambers, Liberty, and Waller Counties beginning May 1, 2004, and increasing the emissions inspection fee. The commission is adopting a phased approach to make for a smoother implementation of the adopted I/M program, while still providing significant air quality improvements. In addition, the adopted rules incorporate changes to the exhaust analyzer technical specifications which will apply in every I/M program area.

The commission solicited comments on the option of Chambers, Liberty, and Waller Counties individually or collectively developing alternative air control strategies, other than an I/M program, to meet or exceed the NO_x emission reductions that are anticipated from the adopted I/M program. The initial estimated I/M NO_x emission reductions for Chambers County were .98 tpd, for Liberty County were .94 tpd, and for Waller County were .77 tpd, for a combined estimated NO_x emissions reduction of 2.69 tpd. The commission considered alternatives during the comment period and made a final determination. However, the remote sensing component implemented in Harris County will continue to cover vehicles registered in these counties even if an alternative control strategy is accepted by the commission.

The commission received thirteen comments to omit Chambers, Liberty, and Waller Counties. All comments are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

In its effort to ensure that the SIP strategies impose no more burden than necessary to protect health and welfare, the commission decided to provide Chambers, Liberty, and Waller Counties, and their respective largest municipality, the flexibility to submit by May 1, 2002, individually or collectively, a resolution that is approved by the commission and the EPA as an alternative air control strategy. The resolution should provide a control strategy that will provide modeled reductions of VOC and NO_x equivalent to the reductions that have been modeled for these counties through the implementation of the I/M program. The estimated "COAST Update October 2000" NO_x emission reductions are: Chambers County, 1.25 tpd; Liberty County, 1.06 tpd; and Waller County, .75 tpd, for a combined estimated NO_x emissions reduction of 3.06 tpd. If emission reductions from the alternative plan are in whole or part from stationary sources, appropriate ratios must be used to reflect the different impact which mobile sources have on air quality.

Based on the EPA notice of proposed rulemaking (NPRM) dated September 20, 2000, "Amendments to Vehicle Inspection Maintenance Program Equipment Requirements Incorporating the Onboard Diagnostic Check," the commission amended the I/M rules to allow OBD testing in lieu of tailpipe testing, for model year vehicles 1996 and newer, beginning May 1, 2002.

The commission solicited comment on additional flexibility relating to rule content and implementation which have not been addressed in this or other concurrent rulemakings. The flexibility may be available for both mobile and stationary sources. Additional flexibility may also be achieved through innovative and/or emerging technology which may become available in the future. Additional funding sources for incentive programs may become available to substitute for some of the measures considered here. The commission received no comments on additional flexibility relating to rule content and implementation.

SECTION BY SECTION DISCUSSION

Adopted amendments to §114.50 establish revised program requirements for the state I/M program. The adopted program amendments concern the applicability and control requirements. The result of these amendments is to incorporate the entire HGA nonattainment area into the full I/M program in a phased manner. Section 114.50(a)(1) has been amended to extend TSI testing until April 30, 2002, to allow flexibility in acquiring new test equipment for the program. This is a change from the proposed rules based upon the EPA NPRM. Section 114.50(a)(2)(A) has been amended to provide for a May 1, 2002 start date for OBD testing in Dallas/Fort Worth (DFW) program area. Also, a new requirement has been added to ensure all vehicles that cannot be OBD tested will receive an EPA-approved tailpipe test. Section 114.50(a)(2)(B) and (C) have been deleted and Subparagraph (D) has been renumbered (B). Section 114.50(a)(3) has been amended by adding vehicles which are "registered and primarily operated in the extended DFW (EDFW), area" and subsection (a)(3)(A) was amended to reflect that vehicles which cannot be OBD tested will receive an EPA-approved tailpipe test. Requirements proposed in §114.50(a)(2) and (3) for all testing stations to offer both an OBD and ASM-2 test have been deleted. Adopted §114.50(a)(4) is amended by deleting "Harris County of" the HGA program area. Section 114.50(a)(4)(A) has been amended to provide for a start date of May 1, 2002, for OBD testing in Harris County. Also, a new requirement has been added to ensure all vehicles registered and primarily operated in Harris County that cannot be OBD tested will receive an EPA-approved tailpipe test. The requirement in this section that the OBD test be conducted in conjunction with the TSI test has been deleted. Subparagraph (B) and proposed new subparagraph (C) have been deleted. New subparagraph (D) has been renumbered (B) and the requirement for emissions test stations to offer both an OBD test and ASM-2 test has been deleted. New subparagraph (E) has been renumbered (C) and the requirement of an ASM-2 test being conducted in conjunction with an OBD test was deleted. Subparagraph (F) has been renumbered (D) and the requirement for emissions test stations to offer both an OBD test and ASM-2 test has been deleted. New subparagraph (G) has been renumbered (E) and the requirement of an ASM-2 test being conducted in conjunction with an OBD test deleted. New subparagraph (H) has been renumbered (F) and the requirement of emissions test stations to offer both an OBD test and ASM-2 test has been deleted. New subparagraph (G) allows Chambers, Liberty, and Waller Counties, and their respective largest municipality to submit by May 1, 2002, individually or collectively, resolutions to implement an alternative control strategy. Should these strategies provide equivalent modeling credits that each of the counties would have received for the I/M program, and they are approved by the commission and the EPA, then subparagraphs (E) and (F) shall not apply. Subsection (a)(5)(A) has been amended to provide for a start date of May 1, 2002, for OBD testing in the El Paso program area. Also, a new requirement has been added to ensure all vehicles that cannot be OBD tested will receive an EPA-approved tailpipe test. Subparagraph (B) has been amended to provide for a start date of May 1, 2002, and the requirement that emissions test stations must offer both TSI and OBD test has been deleted.

Section 114.50(b)(3) is amended by adding "HGA" after EDFW to the program areas and deleting "or Harris County" concerning vehicle recall notification.

Section 114.51 is amended to update the equipment evaluation procedures for vehicle emissions test equipment. This section currently specifies application, certification, maintenance, and service requirements for manufacturers or distributors of vehicle emissions testing equipment seeking approval of an exhaust gas analyzer or analyzer system for use in the Texas I/M program. Section 114.51(a) currently specifies a date of March 15, 2000, for the exhaust analyzer technical specifications known as "Specifications for Preconditioned Two Speed Idle Vehicle Exhaust Gas Analyzer Systems for use in the Texas Vehicle Emissions Testing Program." In order to incorporate new and updated specifications into the program, the adopted rule amendments specify a date of November 1, 2000, for both the TSI exhaust analyzer technical specifications, and the "Specifications for Acceleration Simulation Mode Vehicle Exhaust Gas Analyzer System for use in the Texas Vehicle Emissions Testing Program."

Proposed amendments to §114.52 would have established the schedule for when motorists in specific counties become eligible for waivers and extensions. The schedule was consistent with the dates for the implementation of the annual emissions testing program in each county. However, the proposed language implied that motorists who fail an on-road test would not be able to apply for a waiver. The commission determined that the proposed revision was not needed and therefore removed the proposed language on adoption.

Adopted amendments to §114.53 establish fee schedules for the different counties which must be paid for the vehicle emissions inspection at an inspection station. Section 114.53(a)(1) has changed to reflect TSI testing will be performed through April 30, 2002, in Dallas, Tarrant, Harris, and El Paso program areas. Inspection stations conducting TSI testing through April 30, 2002, shall collect a test fee of $13 and shall remit $1.75 to the Texas Department of Public Safety (DPS). Paragraphs (2) - (5), relating to I/M inspections fees, have been deleted and replaced with language that clarifies emissions inspection test fees. The new language organizes test fees and start dates by program areas making it clear and concise. New paragraph (2) is being adopted to provide for the collection of fees by those inspection stations in El Paso County conducting TSI testing or OBD checks beginning May 1, 2002. Emission inspection stations under paragraph (2) shall collect a test fee of $14. New paragraph (3) explains that in the DFW program area beginning May 1, 2002, and in the EDFW program area beginning May 1, 2003, any emissions inspection station conducting an ASM-2 or OBD emissions test shall collect a test fee of $22.50. New paragraph (4) explains that in the HGA program area in Harris County beginning May 1, 2002, and beginning May 1, 2003 in Brazoria, Fort Bend, Galveston, and Montgomery Counties, and beginning May 1, 2004, in Chambers, Liberty, and Waller Counties any emissions inspection station conducting an ASM-2 or OBD emissions test shall collect a test fee of $22.50. The commission is still considering how much of the test fee should go to the state and will propose future rulemaking to clarify that amount.

In addition to the adopted amendments, the adopted revisions to the SIP narrative clarify the new program elements such as applicability changes; new performance standards; emissions testing network type; emissions testing; affected vehicle populations; enforcement actions related to vehicles and service providers; on-road vehicle emissions testing; and the implementation schedule.

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed the rulemaking action in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and has determined that the rulemaking does not meet 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.

These adopted rules do not meet any of the four applicability criteria for requiring a regulatory analysis of "major environmental rule" as defined in the Texas Government Code. Section 2001.0225 applies only to a major environmental rule the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

As discussed earlier in this preamble, this rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register,* or were included in the HGA SIP considered by the commission on December 6, 2000, and planned to be submitted to EPA by December 31, 2000.

The adopted amendments to Chapter 114 are intended to protect the environment or reduce risks to human health from environmental exposure to ozone. However, the inspection stations in and around nonattainment areas would not normally be considered a sector of the economy. In addition, the commission structured the fees in this program to ensure that most additional equipment costs can be recovered. Therefore, the adopted rules do not 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 adopted amendments are intended to establish a vehicle emissions testing program as part of the control strategy to reduce NO_x emissions necessary for the counties included in the HGA nonattainment area to be able to demonstrate attainment with the ozone NAAQS. The adopted amendments are one element of the HGA Post-1999 Rate-of-Progress/Attainment Demonstration SIP. As defined in Texas Government Code, §2001.0225 only applies to a major environmental rule, the result of which is to: exceed a standard set by federal law, unless the rule is specifically required by state law; exceed an express requirement of state law, unless the rule is specifically required by federal law; exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program, or; adopt a rule solely under the general powers of the agency instead of under a specific state law. This rulemaking does not meet any of these four applicability requirements of a "major environmental rule."

These rules do not exceed an express standard set by federal law, since they implement requirements of the FCAA. Specifically, the emission testing program within this proposal was developed in order to meet the ozone NAAQS set by the EPA under 42 USC, §7409, and therefore meets a federal requirement. Provisions of 42 USC, §7410, require 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. These rules were specifically developed as part of an overall control strategy to meet the ozone NAAQS set by the EPA under 42 USC, §7409. Both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling, and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to achieve reductions in ozone precursor emissions in the HGA nonattainment area. Additionally, nonattainment areas which are classified as severe are specifically required to include enhanced inspection and maintenance programs as part of their SIP under 42 USC, §7511a. These rules are adopted to meet that provision. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. By policy, the EPA requires photochemical grid modeling to demonstrate whether the 42 USC, §7511a(f), NO_x measures would contribute to ozone attainment. The commission has performed photochemical grid modeling which predicts that NO_x emission reductions, such as those required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The 42 USC, §7511a(f), exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under 42 USC, §7511a(f), was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

During the 75th Legislative Session, Senate Bill (SB) 633 amended the Texas Government Code to require agencies to perform a regulatory impact analysis (RIA) of certain rules. The intent of SB 633 was to require agencies to conduct an RIA of extraordinary rules. 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 previously discussed, 42 USC 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 proposes and 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.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp,* 919 S.W.2d 485. 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue,* 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.,* 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ); *Cf. Humble Oil & Refining Co. v. Calvert,* 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd,* Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor,* 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.,* 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore, in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, 382.017, 382.019, 382.037 - 382.038, and 382.039 authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

Comments received during the comment period regarding the draft RIA are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

TAKINGS IMPACT ASSESSMENT

The commission evaluated this rulemaking action and performed an analysis of whether the rules are subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. The specific purpose of the rulemaking action is to implement a revised I/M program in the HGA ozone nonattainment area as part of the strategy to reduce emissions of ozone precursors necessary for the area to be able to demonstrate attainment with the ozone NAAQS.

Promulgation and enforcement of the rules will not burden private, real property because this rulemaking action does not require the installation of permanent equipment. Also, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rule amendments 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 significantly advance the health and safety purpose. In addition, §2007.003(b)(4) provides that Chapter 2007 does not apply to these adopted rules since they are reasonably taken to fulfill an obligation mandated by federal law. The amendments will implement requirements of 42 USC, §7410. This action is taken in response to the HGA area exceeding the NAAQS for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient NO_x and ozone levels in HGA. Attainment of the ozone standard will eventually require substantial NO_x reductions. Any NO_x reductions resulting from the current rulemaking are no greater than what the best scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard. Additionally, these rules are adopted to meet the requirement of 42 USC, §7511a, that a severe nonattainment area include an enhanced inspection and maintenance program as part of the SIP.

The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the

HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. For these reasons the rules do not constitute a takings under Chapter 2007 and does not require additional analysis. Comments received during the comment period regarding the takings impact assessment (TIA) are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission determined that this rulemaking action relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et seq.), and the commission rules in 30 TAC Chapter 281, Subchapter B, Consistency with the CMP. 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 reviewed this rulemaking action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and determined that the action is consistent with the applicable CMP goals and policies. The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(l)). No new air contaminants will be authorized and NO_x air emissions will be reduced as a result of these rule amendments. The CMP policy applicable to this rulemaking action is the policy (31 TAC §501.14(q)) that commission rules comply with federal regulations in 40 Code of Federal Regulations (CFR) to protect and enhance air quality in the coastal area (31 TAC §501.14(q)). This rulemaking action will have a beneficial effect on SIP emissions reduction obligations relating to reasonable further progress and attainment demonstrations by making additional emissions reductions over those made by the existing I/M program. Therefore, in compliance with 31 TAC §505.22(e), this rulemaking is consistent with CMP goals and policies.

The commission solicited comments on the consistency of the proposed rules with the CMP during the public comment period and received no comments.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000.

Forty-six persons provided oral testimony at the hearings and 167 persons submitted written testimony. The following provided both oral and/or submitted written testimony: Alliance of Automobile Manufacturers (Alliance); Association of International Automobile Manufacturers (AIAM); Baker Botts (Baker Botts); Brazoria County Judge John Willy (Brazoria County); Brazoria County Commissioners Court through Brazoria County Criminal District Attorney's Office (Brazoria CCC); Business Coalition for Clean Air (BCCA); Chambers County Judge Jimmy Sylvia (Chambers County); City of Houston (Houston); City of Missouri City (Missouri City); Environmental Systems Products (ESP); ExxonMobil Corporation (ExxonMobil); Grandparents of East Harris County (GEHC); Harris County Judge Robert Eckels (Harris County); Houston-Galveston Area Council (HGAC); JB Services (JBS); Liberty County Judge Lloyd Kirkhall (Liberty County); Liberty County Sheriff Gregg Arthur (Liberty County Sheriff); Montgomery County Judge Allen Sadler (Judge Sadler); Mothers for Clean Air (MCA); National Motorists Association (NMA); Phillips 66 Company (Phillips 66); Regional Air Quality Consensus Group (RAQCG); HGAC on behalf of the RAQCG (RAQCG); Sierra Club, Houston Regional Group (Sierra-Houston); Jan Horn on behalf of State Representative Jerry Madden Representative Madden); State Representative Zeb Zbranek (Representative Zbranek); Laura Silagy on behalf of State Senator David Bernsen (Senator Bernsen), SPX Corporation (SPX); Texas Association of Business and Chambers of Commerce (TABCC); Texas Automotive Dealers Association (TADA); Texas Chemical Council (TCC); the League of Women Voters of Texas (LWV-TX); EPA, and 186 individuals.

The following commenters generally supported the proposal: Alliance, Baker Botts, BCCA, Houston, ESP, ExxonMobil, GEHC, Harris County, JBS, HGAC, MCA, Phillips 66, RAQCG, Representative Madden, SPX, TABCC, TCC, LWV-TX, the EPA, and 34 individuals.

The following commenters generally opposed the proposal: Brazoria County, Chambers County, Missouri City, Liberty County, Montgomery County, NMA, Sierra-Houston, Liberty County Sheriff, TADA, and 40 individuals.

The following commenters suggested changes to the proposal as stated in the ANALYSIS OF TESTIMONY section of this preamble: Alliance, AIMA, Chambers County, ESP, Houston, Harris County, HGAC, Sierra-Houston, Liberty County, LWV-TX, MCA, Judge Sadler, RAQCG, Representative Zbranek, Senator Bernsen, SPX, TADA, and 39 individuals.

ANALYSIS OF TESTIMONY

Emissions Testing Fees

Three individuals did not want the test fee increased. In addition, 17 individuals expressed concern that raising the test fee will place a burden on the elderly, young people, and those who are the least able to afford the probable additional cost of car repair, or replacement.

The fee increase is necessary to cover the cost of purchasing new vehicle emissions test equipment and associated costs to include, but not limited to, labor, training, warranties, insurance, and consumable items (such as calibration gases) used in conducting emissions tests. However, vehicles that are properly maintained should have no problem passing the emissions test regardless of their age. In the event that repairs are necessary, the commission acknowledges that these vehicle repairs may be costly, but there are mechanisms in place (waivers and extensions) that help alleviate the cost of emissions repairs for those who need help. The vehicle emissions testing program includes two waiver options: the minimum expenditure waiver, and the individual vehicle waiver. The minimum expenditure waiver is available to those who have made repairs to their vehicle within the established criteria and met the dollar limits established by the EPA rule. The individual vehicle waiver is for those who cannot meet emissions standards despite every reasonable effort by the motorist. In addition to these two waivers, the low-income time extension is available for those who can demonstrate a financial inability to either afford adequate repairs or meet the applicable minimum expenditure waiver amount. The waivers and time extension are a way to ensure that motorists who are making a "good faith" effort to comply with the I/M program requirements do not incur excessive repair costs and are not excessively inconvenienced. The commission made no changes to the rule in response to this comment.

Vehicle Coverage

A classic car collector wanted to know what the requirements will be for his 1974, 1975, and 1977 cars in Brazoria County starting in 2003.

Section 114.50(a) excludes antique vehicles registered with the Texas Department of Transportation (TxDOT) from emissions testing. Additionally, the program is designed with a "rolling" 24-year window with the most recent 24 model years being subject to the I/M program. The "rolling" 24-year window option was selected due to the small amount of vehicles that are on the road after 25 years and the large percentage of those on the road being classified as classics and/or antiques, which are not subject to emissions testing. In 2003, emissions testing is required only on vehicles 2 - 24 years of age, because none of the stated vehicles will be required to undergo emissions testing.

Four individuals wanted tailpipe testing for all vehicles, including gasoline-powered trucks and sport utility vehicles (SUV).

The I/M program tests all model year 2 - 24 years gasoline-powered vehicles, including trucks and SUVs. This allows a two-year exemption for the newest vehicles which are less likely to fail an emissions test. Vehicles that are 25 years and older are exempt for several reasons: many older vehicles were not required to have many of the pollution control devices now required; a large percentage of vehicles in this age group are classified as classics or antiques; and the vehicles in this age group make up a small percentage (approximately 2.5%) of the total fleet and drive fewer miles per year making their overall emissions impact relatively small. The commission made no changes to the rule in response to this comment.

The RAQCG and the HGAC supported the proposed I/M program, but recommended that the commission should consider a fee for exempting newer model year vehicles from testing, and the proceeds of such fees to be used for purchasing or removing high-emitting vehicles from the region's fleet or other emissions reduction programs.

As the requirement to test vehicles 2 - 24 years old is established by the state legislature (SB 1856 of the 75th Legislature), the commission does not have the authority to exempt some of these model years from the program. The commission made no changes to the rules in response to these comments.

Two individuals recommended exempting vehicles under five years of age. In addition, it was also recommended that vehicles over 25 years old should be exempt and should pay a fee that could be used to fund other NO_x reduction projects.

The requirement to test vehicles 2 - 24 years old is set by state statute (SB 1856 of the 75th Legislature). These vehicles account for the vast majority of vehicles on the road and the vehicle miles traveled, which have a direct correlation to the impact on air quality. The failure rate for vehicles less than five years old is approximately 1%. Because some newer models do fail the test and because vehicles subject to the testing are more likely to be properly maintained, the amount of emissions reductions benefits that can be claimed for an I/M program is reduced as more model years are exempted from the program. In addition, since many of the vehicles under five years old are still under the manufacturer's warranty, identifying emissions-related problems could be viewed as consumer protection and potentially may save the vehicle's owner future repair costs.

Vehicles that are 25 years and older are exempt for several reasons: many older vehicles were not required to have many of the pollution control devices now required; a large percentage of vehicles in this age group are classified as classics or antiques; and the vehicles in this age group make up a small percentage (approximately 2.5%) of the total fleet and drive fewer miles per year making their overall emissions impact relatively small.

It is beyond the scope of this rulemaking to charge a fee to owners of vehicles already exempt from the program. The commission made no changes to the rules in response to these comments.

One individual felt that vehicles with rotary powered engines should be exempt from emissions testing since a rotary engine does not produce NO_x emissions. Also, individuals with non-stock (aftermarket) parts that increase performance on their vehicles should be exempt from testing when they can produce less pollutants than a stock-vehicle having proper emissions equipment installed.

According to the National Center for Vehicle Emissions Control and Safety at Colorado State University, all gasoline-powered vehicles produce hydrocarbons (HC), carbon monoxide (CO), and NO_x emissions. This includes rotary engine vehicles. Therefore, these vehicles will not be exempt from emissions testing. If the use of an aftermarket part causes the vehicle tailpipe emissions to be adversely affected, then the modification is considered to be tampering. The EPA anti-tampering enforcement policy states that the EPA will not consider any modification to a certified configuration to be a violation of federal law if there is a reasonable basis that emissions are not adversely affected. Vehicles that have been modified from their original certified configuration will not be exempt from tailpipe testing. The purpose of the testing, which is to ensure that the emissions control system is working properly, is still a valid purpose for modified vehicles. The commission made no changes to the rules in response to these comments.

One individual wanted vehicles over 24 years old tested.

The requirement to test vehicles is set by state statute (SB 1856 of the 75th Legislature). Vehicles that are 25 years and older are exempt for several reasons: many older vehicles were not required to have many of the pollution control devices now required; a large percentage of vehicles in this age group are classified as classics or antiques; and the vehicles in this age group make up a small percentage (approximately 2.5%) of the total fleet and drive fewer miles per year making their overall emissions impact relatively small. The commission made no changes to the rules in response to this comment.

One individual recommended I/M inspections must cover all mobile vehicles (cars to heavy diesel) under conditions realistically simulating in-use operating conditions by mid-year 2002, as well as including tests for catalyst integrity.

The commission is adopting a phased approach to make for a smooth implementation while still providing significant air quality improvements. All gasoline-powered motor vehicles 2 - 24 years old are subject to an annual emissions inspection. Military tactical vehicles, motorcycles, diesel-powered vehicles, dual-fueled vehicles which cannot operate using gasoline, and antique vehicles registered with the TxDOT are excluded from the program. While the commission is currently researching the feasibility of heavy-duty diesel vehicle testing, diesel testing is outside the scope of this rulemaking. The catalytic converter is a major emission control component for the control of NO_x. The ASM-2 test will identify vehicles with excessive NO_x emissions which is usually caused by a malfunctioning catalytic converter or exhaust gas recirculation (EGR) valve. The ASM-2 test, which is required in the HGA nonattainment area, closely simulates in-use operating conditions by using a dynamometer. The commission made no changes to the rules in response to these comments.

One individual recommended all vehicles that are used inside private plants should be required to pass an emissions test.

According to the Texas Transportation Code (TTC), §502.002, the vehicle emissions testing program affects vehicles registered with TxDOT to be driven on public roads. Since the plant's roads are privately-owned, vehicles driven only inside the plant are not required to undergo emissions testing. Since these vehicles are not subject to the safety inspection and vehicle registration program, enforcement of an inspection and maintenance program for these vehicles would not be feasible. The commission made no changes to the rules in response to this comment.

Waivers

One individual wanted to do away with waivers and extensions.

Waivers are a way to ensure that motorists making every "good faith" effort to comply with I/M program requirements do not incur excessive repair costs and/or are not excessively inconvenienced. Waivers are not extended beyond one test cycle. Vehicle owners must meet all requirements and reapply, if necessary, the following year to receive a new waiver for that test cycle.

The minimum expenditure waiver is available to those who have made repairs to their vehicle within the established criteria (to include repairs made within 60 days of an inspection) and have met the dollar limits established by the EPA.

The commission committed to limit all waivers to no more than 3.0% in each program area. Since the inception of the current program, the waiver rate has not exceeded 0.4%. The commission will continue to monitor waiver rates in all program areas. The commission made no changes to the rules in response to this comment.

Remote Sensing

Harris County wanted to work toward utilizing remote sensing as a replacement to tailpipe testing and expanding exemptions to a broader range of late model cars throughout the region. In addition, one individual wanted to know why random monitoring is ineffective in identifying gross polluters.

The commission agrees that remote sensing has a useful role to play in detecting high-emitting vehicles in the I/M program areas. However, currently available remote sensing technologies are not as accurate as a tailpipe test in identifying vehicles that are near the established emissions standards. The commission will continue to evaluate technological advances in remote sensing to ensure the best possible testing methodologies and equipment are considered in future program development. As remote sensing technology improves, it may be considered for expanded use in the I/M program.

The requirement to test vehicles 2 - 24 years old is established by the state legislature (SB 1856 of the 75th Legislature). These vehicles account for the vast majority of vehicles on the road and the vehicle miles traveled, which have a direct correlation to the impact on air quality. The failure rate for vehicles less than five years old is approximately 1.0%. Because some newer models do fail the test and because vehicles subject to the testing are more likely to be properly maintained, the amount of emissions reductions benefits that can be claimed for an I/M program is reduced as more model years are exempted from the program. In addition, since many of the vehicles under five years old are still under the manufacturer's warranty, identifying emissions-related problems could be viewed as consumer protection and potentially may save the vehicle's owner future repair costs. The commission made no changes to the rules in response to these comments.

One individual felt that commuting vehicles from outlying counties driving into Harris or Montgomery County would not be subject to inspections, but would still be polluting the air around Houston every day.

The amended vehicle emissions testing program will require gasoline vehicles 2 - 24 years old, registered in the eight-county HGA nonattainment area to undergo vehicle emissions testing. In addition, remote sensing will be in operation in these counties. The remote sensing element of the vehicle emissions testing program is operated by the DPS and is used to find high-emitting vehicles. The commission made no changes to the rules in response to this comment.

The EPA supported the phased approach as long as non-testing counties continue to be monitored by remote sensing for the vehicle shortfall in the testing areas until the non-testing counties begin testing.

The I/M program will continue to use remote sensing to identify high-emitting vehicles being operated in the nonattainment area in situations where the number of vehicles subject to I/M program is less than the estimated fleet in the nonattainment area. Remote sensing of commuting vehicles will continue until the non-testing counties begin tailpipe testing all subject vehicles. The commission made no changes to the rules in response to this comment.

Representative Zbranek, TADA, and one individual supported the expansion of the remote sensing program to target grossly polluting vehicles.

The I/M program will continue to use remote sensing to identify high-emitting vehicles. The commission agrees that remote sensing has a useful role to play in detecting high-emitting vehicles in the I/M program areas.

TADA recommended that remote sensing be combined with a mandatory smoking vehicle program to ensure that all smoking vehicles are required to be repaired or retired.

The state-wide smoking vehicle program is a voluntary program and relies on conscientious citizens to identify and report vehicles that they observe emitting visible exhaust. Current remote sensing technology does not have the ability to identify the particulate matter and sulfur compounds generally associated with visible exhaust. Future improvements in remote sensing technology, along with enforceable particulate standards for vehicle exhaust emissions, may make possible such a component of the Texas program to control mobile source emissions. The commission made no changes to the rules in response to this comment.

One individual recommended the use of remote sensing to monitor commuting vehicles into Harris County and if vehicles are found to be polluting, recommended sending vehicle owners a notice that their vehicle has to be inspected.

Currently, DPS is operating three remote sensing units in Harris County in order to monitor the emissions of vehicles commuting into the program county from surrounding counties. Owners of vehicles identified as gross polluters receive written notice of the violation instructing them to submit their vehicles to an emissions test at a state-certified emissions testing station for verification of exhaust emissions and to make necessary repairs to bring the vehicle into program compliance. Failure to comply with written notification of an emissions violation is a Class C misdemeanor punishable by a fine of not more than $350. Repeat violations are punishable by a fine of not more than $1,000. The commission made no changes to the rules in response to this comment.

ESP recommended using remote sensing (total screening) as an alternative to I/M testing. Total screening is a combination of clean screening and high emitter identification. Also, one individual recommended improving motorist convenience by exempting from testing those vehicles that have demonstrated through on-road measurements that they do not have high emissions.

The commission agrees that remote sensing has a useful role to play in detecting high-emitting vehicles in the I/M program areas. However, the commission believes that "clean-screening" is not a viable option at this time for the following reasons: 1) the possibilities of false failures increase dramatically as the cut-points for remote sensing failures are more closely aligned to the cut-points of the tailpipe test; and 2) the cost of clean-screening depends on many factors, such as market competitiveness, total number of remote sensing measurements, level of automation, economies of scale, and term of contract. According to the "California Inspection and Maintenance Review Committee Report on Remote Sensing of Vehicle Emissions," dated September 9, 1998, a clean-screening program that exempted 25% of the subject fleet would cost approximately $34 million per year. Although the commission believes that "clean-screening" is not a viable option at this time, the commission will continue to evaluate technological advances in emissions testing to ensure the best possible testing methodologies and equipment are considered in future program development. The commission made no changes to the rules in response to these comments.

Brazoria CCC submitted a report which concludes that remote sensing has little practical value or use in identifying individual, dirty or clean vehicles, that it predicts vehicle emissions at a rate less than chance and that measure emissions with unacceptably wide variations. The report also states that remote sensing can only view a part of the fleet. The commenter also stated that experience and data from remote sensing in Texas show a high percentage of inaccuracy.

The commission acknowledges the comment from Brazoria CCC. The remote sensing program was not implemented for the purpose of replacing annual tail pipe testing. Remote sensing is used as a non-intrusive, but efficient tool to monitor a portion of the vehicle fleet and identify excessive polluters as a complement to traditional mobile source emission control programs. The remote sensing program is designed to detect potentially high-emitting vehicles registered in or commuting into any of the affected nonattainment counties. Owners of vehicles identified as high emitters receive written notice instructing them to submit their vehicles to a tailpipe test at a state-certified emissions testing station to determine compliance with emissions regulations. The commission recognizes that remote sensing is not currently as accurate as the tailpipe test in characterizing vehicle emissions and therefore requires identified vehicles to submit to a confirmatory tailpipe test for validation of the remote sensing results. The commission will continue to evaluate technological advances in remote sensing in order to insure the best possible equipment and testing methodologies are considered in future program development.

One individual recommended remote sensing of vehicles registered in Collin, Denton, and Johnson Counties when driving into the city limits of Dallas, Garland, Richardson, Carrollton, Fort Worth, Grapevine, Southlake, Burleson, and Mansfield.

Remote sensing on highways in the DFW area to identify high-emitting vehicles began in October 1998. Identified high-emitting vehicles may be vehicles either registered in the designated I/M program counties (Dallas and Tarrant Counties) or commuting from surrounding nonattainment counties (Denton and Collin Counties). According to the vehicle emissions testing program adopted April 2000, vehicles 2 - 24 years old, registered in Dallas, Tarrant, Collin, and Denton Counties, beginning May 1, 2002, and Johnson, Parker, Ellis, Kaufman, and Rockwall Counties, beginning May 1, 2003, will be subject to vehicle emissions testing. In addition, remote sensing is currently in operation in the DFW nonattainment area (Dallas, Tarrant, Collin, and Denton Counties) and will be extended to include the other five counties in 2003. All the cities listed in the comment are included in the adopted DFW I/M program area. The commission made no changes to the rules in response to this comment.

One individual advocated remote sensing of vehicles registered in Brazoria, Fort Bend, Galveston, and Montgomery Counties, as well as when driving into the city limits of Pearland, Houston, Katy, Missouri City, Stafford, and Friendwood toward Central Houston.

The amended vehicle emissions testing program will require gasoline vehicles 2 - 24 years old, registered in the eight-county HGA nonattainment area to undergo vehicle emissions tailpipe testing. In addition, the DPS will continue to use remote sensing to identify high-emitting vehicles being operated in the eight counties. All the cities listed in the comment are included in the remote sensing program. The commission made no changes to the rules in response to this comment.

One individual recommended seven requirements for prosecution if a motor vehicle is cited for display of excess tailpipe emissions (remote sensing): 1) diesel or gasoline-powered vehicles 1979 - 1994, gasoline-powered vehicles of model year 1978 or earlier or 1995 -2002, would be sent notices of the need to seek repairs; 2) a peace officer from the sheriff's department, not a constable deputy or trooper, to conduct remote sensing; 3) owner of the motor vehicle must be served in person at his place of residence by a sheriff deputy of the county of residence; 4) vehicle owner to be provided with the time, date, location, and identity of driver; 5) residence of the alleged owner of the accused motor vehicle must be in one of the seven relevant counties, except for a truck tractor assigned to a place of business in any one of the 12 affected counties, drivers of motor vehicles of other counties/states only would get notices of the need to seek repairs; 6) accused allowed a hearing before a Justice of the Peace of the alleged offense with all court costs waived; and 7) citation allowed to be make repairs to get the citation dismissed after the first offense.

The on-road testing component of the Texas I/M program uses remote sensing to identify high-emitting gasoline vehicles. Currently, remote sensing technology does not have the ability to identify the particulate matter and sulfur compounds generally associated with visible exhaust (diesels and smoking vehicles). Future improvements in remote sensing technology, along with enforceable particulate standards for vehicle exhaust emissions, may make possible such a component of the Texas program to control mobile source emissions. Owners of gasoline vehicles identified as high emitters of HC and CO receive written notice of the violation from DPS instructing them to submit their vehicles to an emissions test at a state-certified emissions testing station for verification of exhaust emissions and to make necessary repairs to bring the vehicle into program compliance. Brochures on repairing vehicles are available at each testing station. Failure to comply with written notification of an emissions violation is a Class C misdemeanor punishable by a fine of not more than $350. Repeat violations are punishable by a fine of not more than $1,000.

The commission appreciates the suggestions for enforcement of the remote sensing element of the emissions testing program, but several are outside the commission's jurisdiction. The commission made no changes to the rules in response to this comment.

One individual proposed that vehicle owners be allowed one of the following options should the vehicle fail the remote sensing/emissions test: 1) to appeal to commissioners court for assistance from an "indigent " person fund created by increasing the license plate fee in order make repairs; 2) to sell the vehicle (1986 or older model) to the state in a "buy back" program funded by a local-option motor fuel sales tax of $.02 - $.05 per gallon; 3) move to a place of residence outside of the affected counties.

The commission understands that vehicle repairs can be costly. In order to assist the public, the vehicle emissions testing program includes two waiver options: the minimum expenditure waiver and the individual vehicle waiver. The minimum expenditure waiver is available to those who have made repairs to their vehicle within the established criteria and met the dollar limits established by the EPA rule. The individual vehicle waiver is for those who cannot meet emissions standards despite every reasonable effort by the motorist. In addition to these two waivers, the low income time extension is available for those who can demonstrate a financial inability to either afford adequate repairs or to meet the applicable minimum expenditure waiver amount. The waivers and extension are ways to ensure that motorists who are making a "good faith" effort to comply with the I/M program requirements do not incur excessive repair costs, are not excessively inconvenienced, or are not denied re-registration of their vehicle.

Enforcement of the program is the responsibility of the DPS, TxDOT, and the commission. Vehicles registered in an I/M program area must comply with the safety and emissions testing program (either by passing the test or qualifying for a waiver or extension) to be issued a safety certificate. The commission, TxDOT, and DPS implemented a vehicle re-registration denial enforcement element for vehicles that fail to comply with the emissions testing program. Remote sensing is used to identify high-emitting vehicles commuting into an area and as an additional enforcement mechanism to identify high-emitting vehicles that have not complied with the program. Once a high-emitting vehicle is identified, the owner of the vehicle is instructed by written notice from the DPS to bring the vehicle in to a state-certified emissions testing station for a verification emissions test and to make necessary repairs to bring the vehicle into program compliance. Failure to comply with the notice is a Class C misdemeanor. Local law enforcement officials are responsible for ensuring that vehicles operating on public roads have a valid registration sticker and safety certificate.

Provisions for a tax to create an "indigent person" or "buy back" fund would require legislative authorization and is beyond the scope of this rulemaking.

Currently, 30 TAC Chapter 117, Tax Relief for Property Used for Environmental Proetction, is the commission's program that provides tax relief for the purchase of pollution control property. On November 2, 1993, the voters of Texas approved a constitutional amendment, commonly referred to as "Proposition 2," that provides an exemption from property taxation for pollution control property. The intent of the constitutional amendment was to ensure that capital investment undertaken to comply with federal, state, or local environmental mandates did not result in an increase in a facility's property taxes. Legislation implementing that amendment, House Bill 1920, was passed during the 73rd Texas Legislative session which added a new §11.31 and §26.045 to the Texas Tax Code (Tax Code). The Tax Code provides that pollution control property could include any land purchased after January 1, 1994, or any structure, building, installation, excavation, machinery, equipment, or device and any attachment or addition to or reconstruction, replacement, or improvement of property that is used, constructed, acquired, or installed wholly or partly to meet or exceed rules or regulations adopted by any federal, state, or local environmental agency for the prevention, monitoring, control, or reduction of air, water, or land pollution. Motor vehicles are specifically noted as being ineligible for an exemption under this provision of the Tax Code. The Tax Code contains a two-step process for securing an exemption from property taxes for pollution control property. An applicant must first receive a determination from the commission that the property is used for pollution control purposes. The applicant then can use this determination to apply to the local appraisal district for a property tax exemption. The commission made no changes to the rules in response to these comments.

Program Start-up

The Alliance, AIAM, and the EPA supported the use of OBD checks instead of conventional I/M tests for 1996 and later model year gasoline vehicles. The Alliance, AIAM, and the EPA recommended the OBD checks should not be used in conjunction with I/M testing (i.e., vehicles should not be subject to both an I/M test and an OBD check) since this would lead to unnecessary customer confusion and frustration.

The commission concurs and adopts rules for OBD emissions testing to be used in place of traditional tailpipe testing for 1996 and newer cars in anticipation of the NPRM by the EPA becoming final. The EPA NPRM provides additional flexibility by allowing states to replace the traditional I/M test on model year 1996 and newer vehicles with a check of the OBD system. Thus, the NPRM removes the requirement to perform both a tailpipe test and OBD checks, and authorizes OBD-only checks on 1996 and newer vehicles. In addition, the NPRM extends implementation of OBD checks to January 1, 2002. The commission revised the rules based on the release of the NPRM.

Program Equipment

The Sierra-Houston and one individual recommended I/M 240 centralized inspection and maintenance tailpipe testing in conjunction with OBD testing. In addition, three individuals would like to see a state-run test like the old IM-240.

Because the Houston nonattainment area needs to reduce NO_x emissions, modifications to the current TSI emissions testing program are being adopted. The ASM-2 or equivalent test, which uses a dynamometer, is required for the HGA program area beginning in 2002. An ASM-2 type test is estimated to achieve VOC and NO_x emission reductions comparable to those achieved by an IM-240 type test, but at less than one-third of the cost, and can be implemented through the current decentralized testing network. The EPA NPRM provides additional flexibility by allowing states to replace the traditional I/M test on model year 1996 and newer vehicles with a check of the OBD system. Thus, the requirement to perform both a tailpipe test and OBD checks has been removed and OBD-only checks have been authorized on 1996 and newer vehicles. In addition, the NPRM extends implementation of OBD checks to January 1, 2002. The commission made no changes to the rules in response to these comments.

One individual opposed the ASM-2 test because it is not as efficient as the IM-240 in determining polluting vehicles. He expressed support of OBD as an add-on to IM-240 and wants to know what is meant by "reductions comparable to those achieved by IM-240."

The ASM-2 test achieves modeled VOC and NO_x reductions comparable to those achieved by an IM-240 test but at less than one-third the cost. Moreover, the ASM-2 test is considered effective in identifying high-emitting vehicles, and can be implemented through the current decentralized testing network. The EPA NPRM provides additional flexibility by allowing states to replace the traditional I/M test on model year 1996 and newer vehicles with a check of the OBD system. Thus, the requirement to perform both a tailpipe test and OBD checks has been removed and OBD-only checks have been authorized on 1996 and newer vehicles. In addition, the NPRM extends implementation of OBD checks to January 1, 2002.

The phrase "reductions comparable to those achieved by IM-240" refers to modeled emissions reductions that can be achieved using an alternative I/M testing methodology, such as ASM-2. For example, the level of modeled emissions reductions for the pollutant NO_x using the ASM-2 testing method are approximately the same as the level of modeled emissions reductions for NO_x using IM-240. The commission made no changes to the rules in response to these comments.

TADA supported OBD testing, but disagreed with the use of ASM-2 testing and stated that it will be inconvenient and extremely expensive for the driving public.

More sophisticated photochemical modeling demonstrates that the HGA area needs to reduce NO_x emissions in order to achieve the ozone NAAQS. An ASM-2, or similar test, is estimated to achieve VOC and NO_x emission reductions comparable to those achieved by an IM-240 type test, but at less than one-third of the cost, and can be implemented through the current decentralized testing network which includes over 2,300 testing facilities in the four I/M program counties (Dallas, El Paso, Harris, and Tarrant). The test fee for a loaded mode test like ASM-2 will not be above the average for what is currently charged nationwide for a similar test. As OBD testing is applicable only to 1996 and newer vehicles, a tailpipe test that can measure NO_x emissions, such as ASM-2, must be available in order to test the pre-1996 vehicles. The commission made no changes to the rules in response to these comments.

TADA suggested a more equitable method of paying for emissions testing equipment is to provide a tax credit or exemption.

Provisions for a tax credit or exemption for stations owners would require legislative authorization and is beyond the scope of this rulemaking. The commission made no changes to the rules in response to this comment.

One individual recommended a visual check of the exhaust system should be performed as part of the annual vehicle inspection. If an abnormality is found, such as a loose or broken exhaust or visual smoke, the owner would be required to have a more thorough check and repairs performed, before the vehicle inspection is approved.

The emissions test is conducted annually in conjunction with the vehicle safety inspection. The annual safety inspection procedures consist of a visual exhaust emissions check on 1968 and newer vehicles. The check includes inspection of the exhaust emission system to determine if it has been removed, disconnected or altered in any manner to make it ineffective. If an exhaust leak is detected, then the vehicle must be repaired before the emissions test can be conducted. The commission made no changes to the rules in response to this comment.

One individual stated opposition to the proposed I/M program and believed dyno testing is no better than BAR-90 testing and would like to know the effectiveness of current program.

The commission recently completed its Mass Emissions Transient Testing (METT) study to determine the effectiveness of the current I/M program when compared to the EPA benchmark program for METT study. The Texas TSI I/M program achieves about 84% HC reductions, and about 104% CO reductions, when compared to the Arizona I/M 240 program (EPA's benchmark program). However, TSI testing does not allow for the measurement of NO_x because under idle modes the temperature and pressure in the combustion chambers are not high enough to produce a significant amount of measurable NO_x. In order to help the HGA nonattainment area achieve the necessary NO_x reductions, the current tailpipe test must be upgraded to an alternative test type, such as ASM-2 or equivalent dynamometer test, that can measure NO_x emissions. OBD checks will be given to 1996 and newer model year vehicles. The commission made no changes to the rules in response to these comments.

Repair Program

One individual wanted stricter controls and recommended a one-year warranty on all repairs.

Establishing a one-year warranty on repairs by inspection repair shops is beyond the scope of this rulemaking, and is outside the scope of the commission's jurisdiction to regulate the repair industry for consumer protection. The commission's focus is on the resulting air quality benefits measured after the repair is completed. The commission made no changes to the rules in response to this comment.

Program Convenience

Six individuals expressed the belief that the I/M testing program being proposed is going to hurt those residents that have older cars that were not built with emissions tests in mind.

Vehicles that are properly maintained should have no problem passing the emissions test regardless of their age. Vehicles 2

- 24 years old are required to undergo emissions testing. The cut points which determine whether a vehicle passes or fails are calculated by factors such as the vehicle weight, model year, and engine size. Thus, older vehicles are required to meet standards based on criteria specific to them. The commission made no changes to the rules in response to this comment.

Five individuals expressed opposition to the program and feel the government is too intrusive, putting too many restrictions on consumers, that the I/M test is too expensive, that the proposed rules go far beyond anything necessary to protect the environment, and will be ineffective in reducing the ozone levels.

The I/M program is one of the key strategies necessary to bring the HGA area into attainment of the ozone standards. If the plan is unsuccessful, the HGA area may suffer considerable economic sanctions. In addition, cleaner air provides economic benefits to the community, such as fewer sick days, lower medical costs, and fewer pollution-associated illnesses.

More sophisticated photochemical modeling demonstrates that the HGA area needs to reduce NO_x emissions in order to achieve the ozone NAAQS. An ASM-2, or similar test, is estimated to achieve VOC and NO_x emission reductions comparable to those achieved by an IM-240 type test, but at less than one-third of the cost, and can be implemented through the current decentralized testing network which includes over 2,300 testing facilities in the four I/M program counties (Dallas, El Paso, Harris, and Tarrant). The test fee for a loaded mode test like ASM-2 will not be above the average for what is currently charged nationwide for a similar test. As OBD testing is applicable only to 1996 and newer vehicles, a tailpipe test that can measure NO_x emissions, such as ASM-2, must be available in order to test the pre-1996 vehicles. The commission made no changes to the rules in response to these comments.

Program Network

Two individuals wanted to know what is wrong with the existing program. Also, what percentage of vehicles tested under the current program failed. Also, how much of the ozone is attributed to automobiles in the Houston area.

More sophisticated photochemical modeling demonstrates that the HGA area needs to reduce NO_x emissions in order to achieve the ozone NAAQS. Although the current TSI testing program is considered effective in identifying vehicles grossly polluting for HC or CO, idle testing does not allow for the measurement of NO_x. Under idle modes the temperature and pressure in the combustion chambers are not high enough to produce a significant amount of measurable NO_x. This current TSI test must be upgraded to an alternative test type, such as ASM-2, that can measure NO_x emissions, and therefore achieve significant NO_x reductions.

It is estimated that 24% of the NO_x emissions in the HGA area are from on-road mobile sources, such as vehicles. The current TSI emissions testing program tests vehicles 2 - 24 years old. These vehicles account for the vast majority of vehicles on the road and the vehicle miles traveled, which have a direct correlation to the impact on air quality. The amount of emissions reduction benefits is not only based on repairing failed vehicles (currently approximately 5% fail), but also from vehicles being properly maintained because they are subject to emissions testing. The commission made no changes to the rules in response to these comments.

Four individuals stated that the system in place now is more than adequate. All expressed opposition to the commission reinstating a centralized IM-240 type inspection system.

The commission has no intention of mandating a centralized I/M 240 program. However, in order to help the HGA nonattainment areas achieve the necessary NO_x reductions, the current TSI test must be upgraded to an alternative test type, such as ASM-2, that can measure NO_x emissions, and therefore achieve significant NO_x reductions. An ASM-2 type test is estimated to achieve VOC and NO_x emission reductions comparable to those achieved by an IM-240 test, but at less than one-third the cost, and can be implemented through the same decentralized testing system as is used for the current TSI test. The commission made no changes to the rules in response to this comment.

Alliance, Houston, ESP, ExxonMobil, GEHC, Harris County, JBS, HGAC, MCA, TCC, Phillips 66, BCCA, RAQCG, Baker Botts, Representative Madden, SPX, TABCC, LWV-TX, EPA, and 34 individuals supported the proposed emissions testing program.

The commission appreciates the support for the vehicle emissions testing program.

One individual stated that owners of vehicles certified as low emission or ultra-low emission should not be penalized for living in an area with vehicles that spew pollutants.

All vehicles certified as low emissions and ultra-low emissions should pass the emissions test if they are properly maintained. The amount of emissions reduction benefits is not only based on repairing failed vehicles, but also from all vehicles being properly maintained because they are subject to emissions testing. The commission made no changes to the rules in response to this comment.

Five individuals commented that testing vehicles on a dynamometer is a big mistake. Cars can come off the rollers while testing causing damage to the vehicles.

Emissions testing using dynamometers has been conducted in many states without serious incidents being reported. Compared with the IM-240 test, where the top speed of the car on the dynamometer is 56 miles per hour (mph), the dynamometer's top speed will be 25 mph as prescribed by the ASM-2 type test and the vehicle will be required to be tied down during the test. An intensive training program will be implemented for all inspectors operating a dynamometer type emissions test. The commission made no changes to the rules in response to this comment.

Three individuals felt that small inspection stations will not have room to set up this type of test or be willing to accept responsibility for accidents on this type of equipment. In addition, three individuals expressed concern that $40,000 is more than most inspection stations can afford.

The commission adopted the emissions test fee for the new program in order to cover costs involved in the use of loaded mode test equipment. These costs include labor, training, warranties, insurance, and consumable items (such as calibration gases) used in conducting emissions tests. Based on internal cost analysis of the proposed loaded mode testing program, the commission approved a $22.50 emissions test fee for the new program. According to the cost analysis study at a fee of $22.50/test, for a station to break even in five years, based just on equipment cost of $40,000, a station must perform about 43 emissions tests per month. For a station to break even in five years based on equipment cost combined with an average monthly operating cost of

$1,000, a station must perform about 94 tests per month. Continued participation in the program as it evolves will be a business decision made by each individual station owner. The proposed ASM-2 type dynamometer can be installed above ground in a space approximately 14 feet by 23 feet, which is the same dimensions of most repair bays. The commission made no changes to the rules in response to these comments.

Three individuals expressed concern that there would not be enough emission testing facilities to test their vehicles in the counties.

The current decentralized network improved convenience over the previous centralized network by providing more than 2,300 testing facilities in the original four I/M program counties (Dallas, El Paso, Harris, and Tarrant). The commission and DPS are working to ensure that the program maintains an acceptable ratio of the subject testing fleet to emissions testing stations. The commission made no changes to the rules in response to this comment.

One individual supported the proposed vehicle emissions testing program, but would like to see the city-owned and government-owned vehicles tested also.

The commission appreciates the support for the vehicle emissions testing program. Chapter 114, §114.50(b)(7) requires state, governmental, and quasi-governmental agencies which fall outside the normal registration or inspection comply with all vehicle emissions I/M requirements contained in the Texas I/M SIP for vehicles primarily operated in I/M program areas. The commission made no changes to the rules in response to this comment.

HGAC, Houston, MCA, and 20 individuals recommended establishing a testing program for heavy-duty diesel vehicles. One individual wanted a more thorough and frequent stringent emissions tests for large trucks and buses (gas and diesel) because it appears that these large trucks are the worst violators of clean air.

Approximately 97% of the registered fleet, which is 2 - 24 years old, will be tested using the ASM-2/OBD technology. These vehicles account for the vast majority of vehicles on the road and the vehicle miles traveled, which have a direct correlation to the impact on air quality. Due to equipment limitations, heavy-duty gasoline vehicles (those vehicles over 8,500 pounds) will be tested using the current TSI test. While the commission is currently researching the feasibility of heavy-duty diesel vehicle testing, diesel testing is outside the scope of this rulemaking. The commission made no changes to the rules in response to this comment.

Two individuals stated that since vehicle manufacturers are required by our federal government to install emissions controls on all vehicles made to comply with federal clean air act, why is it that we now need stricter emissions exhaust tests for state inspections?

A major contributor to air pollution is the exhaust from cars and trucks. All over Texas vehicles contribute as much as half of the harmful air emissions that create pollution. One vehicle in bad repair can produce 28 times as much pollution as one vehicle in good repair. Although vehicle manufacturers are required to install emissions controls on all vehicles, improperly maintained emission controlled devices may eventually malfunction. The emissions testing program tests vehicles 2 - 24 years old. These vehicles account for the vast majority of vehicles on the road and the vehicle miles traveled, which have a direct correlation to the impact on air quality. The amount of emissions reduction benefit is not only based on repairing failed vehicles, but also on vehicles being properly maintained because they are subject to emissions testing. In addition, more sophisticated photochemical modeling demonstrates that the HGA area needs to reduce NO_x emissions in order to achieve the ozone NAAQS. The TSI testing does not allow for the measurement of NO_x because under idle modes the temperature and pressure in the combustion chambers are not high enough to produce a significant amount of measurable NO_x. In order to help the HGA nonattainment area achieve the necessary NO_x reductions, the current tailpipe test must be upgraded to an alternative test type, such as ASM-2 or equivalent dynamometer test, that can measure NO_x emissions. On-board diagnostic checks will be given to 1996 and newer model year vehicles. The commission made no changes to the rules in response to this comment.

One individual stated that there are still too many heavy polluters on our roads, particularly pick-ups, poorly maintained cars and commercial trucks.

Identifying and having these vehicles repaired will only help the HGA area achieve the ozone NAAQS. The I/M program covers all gasoline-powered cars and trucks regardless of size. These vehicles represent 97% of the on-road fleet which is 2 - 24 years old. Although the current TSI testing program is considered effective in identifying vehicles grossly polluting for HC or CO, idle testing does not allow for the measurement of NO_x. The current TSI test must be upgraded to an alternative test type, such as ASM-2 with OBD, that can measure NO_x emissions, and therefore achieve significant NO_x reductions. The proposed ASM-2 type test is a more stringent test and estimated to achieve VOC and NO_x emission reductions comparable to those achieved by an IM-240 test, but at less than one-third the cost, and can be implemented through the same decentralized testing system as is used for the current TSI test. In addition, remote sensing is used to identify high-emitting vehicles. Owners of vehicles identified as high-emitters receive written notice of the violation instructing them to submit their vehicles to an emissions test at a state-certified emissions testing station for verification of exhaust emissions and to make necessary repairs to bring the vehicle into program compliance. Failure to comply with written notification of an emissions violation is a Class C misdemeanor punishable by a fine of not more than $350. Repeat violations are punishable by a fine of not more than $1,000. The commission made no changes to the rules in response to this comment.

One individual wanted to install tailpipe testers on major roads to catch the 10% of the vehicles that cause most pollution and rely on the annual test to catch the rest.

In addition to the requirement of all gasoline-powered vehicles 2 - 24 years of age to undergo annual emissions test, remote sensing is used to identify high-emitting vehicles commuting into an area and as an additional enforcement mechanism to identify high-emitting vehicles that have not complied with the program. Once a high-emitting vehicle is identified, the owner of the vehicle is instructed by written notice from the DPS to bring the vehicle in to a state-certified emissions testing station for a verification emissions test and to make necessary repairs to bring the vehicle into program compliance. The commission made no changes to the rules in response to this comment.

Five individuals wanted to see California I/M standards implemented in Houston and six individuals wanted to see California I/M standards implemented statewide.

The State of California is currently operating an emissions testing program that uses the ASM-2 testing technology and will incorporate the OBD testing technology. Modifications to the current emissions testing program in Texas are also being adopted to include the ASM-2 testing technology, and OBD testing technology in the designated I/M program areas. ASM-2 testing technology will be used on 1995 and older model year vehicles. On-board diagnostic testing technology will be used on 1996 and newer model year vehicles. Expansion of the I/M program in all counties is beyond the scope of this rulemaking and may require legislative authority. However, TTC, §548.301(b) and Texas Health and Safety Code, §382.037(c) allow the commission to establish by rule an I/M program in any county provided the county and its most populous municipality adopt a resolution requesting such a program. The commission has not received any such resolution to allow for implementation statewide. The commission made no changes to the rules in response to these comments.

One individual suggested that legislation to require technological means to clean up the dirtiest engines is be more effective and cause less disruption of life style.

The commission does not have the authority to write legislation, but to only enact rules based on current legislative authority. The proposed amendments to the vehicle emissions testing program are one part of an overall clean-air strategy for the state. Because of the scale of the HGA air quality problem the commission is adopting a wide range of rules, including both vehicle testing and technology solutions. The commission made no changes to the rules in response to this comment.

Five individuals suggested a tax supported program to assist the poor in improving their vehicles would be acceptable, if designed to minimize abuse.

Establishing a tax to assist the poor in improving their vehicles is beyond the scope of this rulemaking and requires legislative authority. The commission made no changes to the rules in response to this comment.

Four individuals commented that the proposed tailpipe test could not be enforced and had too many loopholes (i.e., buying without having vehicle inspected).

Enforcement of the program is the responsibility of the DPS, TxDOT, and the commission. Vehicles registered in an I/M program area must comply with the safety and emissions testing program to be issued a safety certificate. The commission, TxDOT, and DPS implemented a vehicle re-registration denial enforcement element for vehicles that fail to comply with the emissions testing program. In counties subject to emissions testing, owners of vehicles that fail an emissions test and do not demonstrate proof of compliance can not re-register or obtain their registration certificate until obtaining proof that their vehicle complies with the emissions testing program. Remote sensing is used to identify high-emitting vehicles commuting into an area and as an additional enforcement mechanism to identify high-emitting vehicles that have not complied with the program. Once a high-emitting vehicle is identified, the owner of the vehicle is instructed by written notice from the DPS to bring the vehicle in to a state-certified emissions testing station for a verification emissions test and to make necessary repairs to bring the vehicle into program compliance. Failure to comply with the notice is a Class C misdemeanor. Local law enforcement officials are responsible for ensuring that vehicles operating on public roads have a valid registration sticker and safety certificate.

The DPS routinely conducts covert and overt audits on inspection stations to identify personnel fraudulently selling stickers. Personnel that are caught are prosecuted in accordance with the law. The commission made no changes to the rules in response to this comment.

Five individuals wanted local law enforcement agencies to strictly enforce the new tailpipe test for automobiles and trucks.

Enforcement of the program is the responsibility of the DPS, TxDOT, and the commission. Vehicles registered in an I/M program area must comply with the safety and emissions testing program to be issued a safety certificate. The commission, TxDOT, and DPS implemented a vehicle re-registration denial enforcement element for vehicles that fail to comply with the emissions testing program. Remote sensing is used to identify high-emitting vehicles commuting into an area and as an additional enforcement mechanism to identify high-emitting vehicles that have not complied with the program. Once a high-emitting vehicle is identified, the owner of the vehicle is instructed by written notice from the DPS to bring the vehicle in to a state-certified emissions testing station for a verification emissions test and to make necessary repairs to bring the vehicle into program compliance. Failure to comply with the notice is a Class C misdemeanor. Local law enforcement officials are responsible for ensuring that vehicles operating on public roads have a valid registration sticker and safety certificate. The current decentralized I/M program has mechanisms in place to prevent fraud and ensure compliance, such as referee challenge facilities, citations, fines, registration denial, and covert audits. The commission made no changes to the rules in response to this comment.

Five individuals stated that too many dilapidated and unsafe cars and trucks were on the road and must be brought up to standards, taken off the road, or scrapped.

The TTC, §502.009, states that if a vehicle has passed the safety and emissions test it is legal for that vehicle to be driven on the road. Motorists are issued citations by local and state law enforcement officials for driving a vehicle with an expired or invalid state inspection certificate, or for evading the emissions inspection or inspection outside of the affected area. These violations of TTC, §548.602 (Class C misdemeanor) and §548.603 (Class B misdemeanor) are respectively punishable by a fine starting at $200 and not exceeding $2,000 for each occurrence. The owner will be subject to an additional citation every time the vehicle is driven. Violators are given notification that they must comply with the I/M program requirements. Noncompliance will result in delivery of additional citations and fines which may accumulate to more than the expense of a minimum expenditure waiver. For those vehicles that fail to comply with the emissions testing program, a vehicle re-registration denial enforcement element has been implemented. In addition, remote sensing is used to identify high-emitting vehicles commuting into an area and as an additional enforcement mechanism to identify high-emitting vehicles that have not complied with the program. Once a high-emitting vehicle is identified, the owner of the vehicle is instructed by written notice from the DPS to bring the vehicle in to a state-certified emissions testing station for a verification emissions test and to make necessary repairs to bring the vehicle into program compliance. Failure to comply with the notice is a Class C misdemeanor. Ultimately, local law enforcement officials are responsible for ensuring that vehicles operating on public roads have a valid registration sticker and safety certificate. Although the commission does not currently implement a scrappage program, the commission adopted rules in April 2000 which enabled and helped define locally run scrappage programs. The commission made no changes to the rules in response to this comment.

One individual recommended that ample test lanes be provided and consumer protection criteria built into the program if IM-240 is utilized.

The commission is not recommending the adoption of an IM-240 program. The ASM-2 test for model year vehicles 1995 and older and the OBD check for model year vehicles 1996 and newer will be offered in the decentralized test and repair network. The commission made no changes to the rules in response to this comment.

One individual wanted to know what happened to the "choice" in the Texas Motorist Choice Program. We were told we would have a choice between centralized and decentralized I/M.

The proposed amendments to the emissions testing program do not change any of the choices motorists had under the Texas Motorists Choice Program. The TSI testing program improved convenience by providing over 2,300 decentralized testing facilities in the original four I/M program counties (Dallas, El Paso, Harris, and Tarrant). This decentralized network allows motorists a choice of test-and-repair or test-only facilities that offer the required emissions and gas cap integrity test. Test-only facilities may offer other services for the convenience of their customers, such as, but not limited to, oil changes, self-serve gasoline, and any other items that are not related to automotive parts, sales, and/or service. Test and repair facilities may offer a wide range of repairs and services for the convenience of their customers. The amended program will use this decentralized network to offer the same choices to motorists. However, continued participation in the program as it evolves will be a business decision made by each individual station owner. The commission made no changes to the rules in response to this comment.

One individual commented that the local industry proposal is far superior to the plan proposed by the commission.

The proposed amendments to the vehicle emissions testing program are only one part of the regional air control strategy. In order to achieve the ozone NAAQS, the HGA area needs to reduce NO_x emissions. An ASM-2, or similar test, is estimated to achieve VOC and NO_x emission reductions comparable to those achieved by an IM-240 type test, but at less than one-third of the cost, and can be implemented through the current decentralized testing network. The commission made no changes to the rules in response to this comment.

Representative Zbranek, Judge Lloyd Kirkhall of Liberty County, Senator Bernsen, and two individuals recommended omitting Liberty and Chambers Counties from the proposed program. Representative Zbranek also wanted the commission and the EPA to justify why Liberty and Chambers Counties should be included in the proposed program when modeling shows otherwise. Judge Sadler and three individuals recommended omitting Montgomery County from the proposed I/M testing program. The RAQCG, Harris County, and the HGAC supported the I/M program being proposed but recommended the commission omit the counties of Chambers, Liberty, and Waller and other appropriate counties from the I/M program based on the small amount of mobile source emissions from these counties. In addition, one individual made two recommendations: 1) omit Liberty County from the proposed I/M program; and 2) to have inclusion in I/M by some other geographical boundary, such as the border of the Trinity River or precincts which actually join Houston and have large numbers of people that commute into Houston.

In the HGA area, eight counties have been designated as nonattainment for the ozone NAAQS: Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties. Photochemical modeling demonstrated that reductions of both NO_x and VOC are required over the entire eight-county area. While the commission adopted the ASM-2 plus OBD I/M program for all eight counties, it included a provision in the rules to allow Chambers, Liberty, and Waller Counties the flexibility of replacing the I/M program with an alternative control strategy, as long as the proposed strategy achieves VOC and NO_x reductions equivalent to those from the I/M program. The concept of redefining the I/M program area by geographical boundaries would prove very difficult to implement, especially due to the focus on county of registration in the program enforcement.

Missouri City wanted to know if its city vehicles are exempt from additional inspection and from additional test fees.

The vehicle I/M program requires annual testing of all gasoline-powered motor vehicles (including city and state-owned vehicles and leased vehicles) that are 2 - 24 years old, primarily operated and registered, or required to be registered, in the affected counties. There is no exemption for government vehicles. The commission made no changes to the rules in response to this comment.

One individual generally supported the program but recommended mandatory emissions testing every three years.

The commission appreciates the support of the vehicle emissions testing program. Vehicle emission testing is an integral part of the total air control strategy. Emission reduction credits achieved by any type of I/M program are reduced significantly when the program is not implemented as an annual test. The commission made no changes to the rules in response to this comment.

One individual recommended allowing individuals to report license plate numbers from smoking vehicles to a police computer. After three reports, a letter would be sent out instructing the motorist to bring the vehicle in for testing. If the vehicle passes the inspection, the inspection is free. If the vehicle fails, the owner is charged an inspection fee and given 30 days to fix, repair, sell, retire, or destroy the vehicle.

The commission implements a state-wide smoking vehicle program which relies on conscientious citizens to identify and report vehicles that they observe emitting visible exhaust. Citizens may report vehicles by an established hotline (1-800-453-SMOG(7664)) or through the WEB at WWW.SMOKINGVEHICLE.ORG. Letters and informational brochures on causes of excessive smoke are sent to vehicle owners encouraging them to have their vehicle checked, and if necessary, repaired. The commission does not plan to change this program at this time. The commission made no changes to the rules in response to this comment.

One individual recommended that vehicle inspection facilities be open 24 hours a day.

There are currently more than 2,300 emissions testing facilities in the original four I/M program counties (Dallas, El Paso, Harris, and Tarrant). According to DPS safety and emissions station requirements, an inspection station must be open at a minimum of 40 hours per week. The actual operational hours are a business decision made by each individual station owner and are outside the scope of this rulemaking. If there is a demand for after hours testing the commission expects that the market would respond.

However, it would not be reasonable to require every station to provide this service. The commission made no changes to the rules in response to this comment.

SPX supported the proposed ASM-2/OBD testing program with the following provisions: implement the enhanced I/M program as soon as possible in all areas; test fees should be market driven; continue the proposed program for a minimum of five years; commission specify that BAR-97 certification be a minimum requirement for companies providing equipment to the new program; and use on-road remote sensing as one of the tools the commission will use for program evaluation. In addition, TADA commented that a market-based fee system would be appropriate if ASM-2 testing is adopted.

The commission is adopting a phased approach to make for a smooth implementation while still providing significant air quality improvements. ASM-2 and OBD testing will be implemented in Harris, Dallas, Tarrant, Denton, and Collin Counties beginning May 1, 2002; in Brazoria, Fort Bend, Galveston, Montgomery, Ellis, Johnson, Kaufman, Parker, and Rockwall Counties beginning May 1, 2003; and in Chambers, Liberty, and Waller Counties beginning May 1, 2004.

The commission believes a fixed fee to be more equitable across the market place by allowing for consistency of price within program areas and provides consumer protection. The commission made no change to these rules.

An emissions testing program is required by federal law and has been authorized to be implemented through Texas state law. The program is subject to change based on changes that could occur in the federal and/or state laws which authorized the current program. Because the program is subject to this authorization, the commission cannot guarantee the program for any set amount of time. Purchasing new testing equipment is a business decision and is the responsibility of the buyer at any given point in time to determine if an investment in an analyzer is worth the cost. Furthermore, as technology evolves over time, the commission will continue to evaluate technological advances in emissions testing to ensure the best possible testing methodologies and equipment are considered in future program development.

The commission concurs with the minimum requirement for all companies to submit proof that the test equipment which they plan to provide as a part of the new program has received BAR97 certification. The specifications for test equipment used in the new program contain this requirement.

Remote sensing is an integral part of the I/M program. Although it is not used as part of the program evaluation, it is used to capture the requirement of on-road testing and used to identify high-emitting vehicles registered in the designated I/M program areas. The current method that is used by staff for I/M program evaluation is the EPA-approved Sierra Research method for METT. The commission will continue to evaluate technological advances in methods for I/M program evaluation.

The commission made no changes to the rules in response to these comments.

SPX stated that the alternative test procedures study completion date may be too late to have an impact on program design decisions and recommended that the study be completed sooner or abandoned in favor of a generally accepted I/M program design.

The commission is conducting a study that will evaluate the use of an alternative test procedure. The scheduled completion date for the study is February 2001. The commission believes that this date will provide sufficient time to implement any necessary program changes. The commission made no changes to the rules in response to this comment.

TADA commented that small business owners will decline to participate in an ASM-2 program because the equipment is more expensive, higher wages will have to be paid for more qualified inspectors, and insurance and liability claims will increase due to dynamometer testing. In addition, Judge Sylvia of Chambers County expressed concern that the proposed I/M program will place a heavy burden on his constituents. Judge Sylvia also expressed concern that there will not be enough testing stations that can afford the $40,000 for new equipment and enough testing stations to perform the emissions test.

The commission adopted a fee of $22.50 for both the ASM-2 and OBD tests in order to cover costs involved in the use of loaded mode test equipment. These increased costs include labor, training, warranties, insurance, and consumable items (such as calibration gases) used in conducting emissions tests. Continued participation in the program as it evolves will be a business decision made by each individual station owner. However, staff are in discussion with analyzer manufacturers to identify ways to relieve the economic burden for inspection station operators at the outset of the program. The commission made no changes to the rules in response to these comments.

Representative Madden generally supported the program, but made two comments regarding the proposed I/M program. First, Representative Madden did not want to have any contractual obligations as the state had with the previous testing contractor, Tejas. Second, he wanted to ensure that there will time to evaluate the vehicle test project now in the DFW area and included in the SIP area so that there will be flexibility to modify the requirement of better testing methods for NO_x produced or if the same results are produced by a less costly test method.

The commission has no intention of contracting with one company to implement a centralized testing system as was the case with the original IM-240 program. The I/M program will continue to be implemented using a decentralized network comprised of individual inspection station owners. However, some specialized portions of the program such as remote sensing and computerized data management are currently contracted out. These contracts do not approach the magnitude of the Tejas contracts.

The commission included flexibility in the rules and SIP to change the testing methodology based on the results of the vehicle technology testing project if the alternative testing technology proves to be as or more effective than the proposed ASM-2 testing methodology in identifying vehicles with excessive NO_x emissions. The commission believes there will be sufficient time to do this, decided, before the first implementation date of May 1, 2002. The commission made no changes to the rules in response to these comments.

One individual recommended that owners of polluting vehicles pay a stiff fine for driving on city streets.

Vehicles registered in an I/M program area must comply with the safety and emissions testing program to be issued a safety certificate. Motorists are issued citations by local and state law enforcement officials for driving a vehicle with an expired or invalid state inspection certificate. These violations of the TTC, §548.602 (Class C misdemeanor) and §548.603 (Class B misdemeanor) are respectively punishable by a fine starting at $200 and not exceeding $2,000 for each occurrence. The owner is subject to a possible additional citation every time the vehicle is driven. Violators are given notification that they must comply with the I/M program requirements. Noncompliance will result in delivery of additional citations and fines. In addition, remote sensing is used to identify high-emitting vehicles commuting into an area and as an additional enforcement mechanism to identify high-emitting vehicles that have not complied with the program. When a high-emitting vehicle is identified, the owner of the vehicle is instructed by written notice from the DPS to bring the vehicle in to a state-certified emissions testing station for a verification emissions test and to make necessary repairs to bring the vehicle into program compliance. Failure to comply with the notice is a Class C misdemeanor. Local law enforcement officials are responsible for ensuring that vehicles operating on public roads have a valid registration sticker and safety certificate. According to the TTC, Chapter 548, vehicles failing to have a valid safety and emissions certificate could range from a Class C misdemeanor to a second degree felony, based on the charge. The fine could range from $200 to $10,000 and potentially involve confinement in a state jail. The commission made no changes to the rules in response to this comment.

One individual recommended the commission avoid proposals not based on proven technologies i.e., tailpipe testing.

The commission is adopting a tailpipe test method that is accepted by the EPA through research conducted by the National Center for Vehicle Emissions Control and Safety at Colorado State University. The I/M program checks whether the emission control system on a vehicle is working correctly. All new passenger cars and trucks sold in the United States today must meet stringent pollution standards, but they can only retain this low-pollution profile if the emission controls and engine are functioning properly. The I/M program is designed to ensure that vehicles stay clean in actual consumer use. Through annual vehicle emissions inspection and required repairs for vehicles that fail the test, the I/M program encourages proper vehicle maintenance and discourages tampering with emission control devices. I/M programs have been implemented for many years and the technology has been proven effective.

State Compliance

One individual in Liberty County suggested that the current program has only a 40% compliance rate.

Current I/M program data and a 1996 vehicle safety inspection sticker compliance rate survey for Dallas, El Paso, Harris, and Tarrant Counties (Appendix J of the SIP) suggests a compliance rate of approximately 96%. The commission will continue to monitor the program's compliance rate.

Motorist Compliance

Two individuals commented that stricter exhaust emission checks are just another way to pay more money for inspection stickers and squeeze revenue from the consumer. They believed most vehicles will pass anyway and for those that fail, there are plenty of places that will pass you for an extra $10 under the table.

More sophisticated photochemical modeling demonstrates that the HGA area needs to reduce NO_x emissions in order to achieve the ozone NAAQS. The current TSI test does not identify NO_x emissions because under idle modes, the temperature and pressure in the combustion chambers are not high enough to produce a significant amount of measurable NO_x. In order to help the HGA nonattainment area achieve the necessary NO_x reductions, the current tailpipe test must be upgraded to an alternative test type, such as ASM-2, that can measure NO_x emissions. OBD checks will be given to 1996 and newer model year vehicles. An ASM-2, or similar test, is estimated to achieve VOC and NO_x emission reductions comparable to those achieved by an IM-240 type test, but at less than one-third of the cost, and can be implemented through the current decentralized testing network which includes over 2,300 testing facilities in the four I/M program counties (Dallas, El Paso, Harris, and Tarrant). The test fee for a loaded mode test like ASM-2 will not be above the average of what is currently charged nationwide for a similar test. As OBD testing is applicable only to 1996 and newer vehicles, a tailpipe test, such as ASM-2, must be available in order to test the pre-1996 vehicles.

A major contributor to air pollution is the exhaust from cars and trucks. All over Texas vehicles contribute as much as half of the harmful air emissions that create pollution. One vehicle in bad repair can produce 28 times as much pollution as one vehicle in good repair. Even though vehicle manufacturers are required to install emissions controls on all vehicles, improperly maintained emissions controlled devices may eventually malfunction. The amount of emissions reduction benefit is not only based on repairing failed vehicles, but also on vehicles being properly maintained because they are subject to emissions testing.

To combat fraud and abuse in the emissions testing program, mechanisms are in place to prevent fraud and ensure compliance, such as referee challenge facilities, citations, fines, registration denial, and covert and overt audits of inspection stations.

The commission made no changes to the rules in response to these comments.

Two individuals recommended deleting the visual examination (parameter check) to verify that certain factory equipment remains installed on the vehicle. In addition, the visual examination prevents the car owner from improving on the original design of the car and further reducing emissions and/or improving fuel economy.

Vehicle configurations are certified by the EPA. The FCAA, §203(a)(3) (42 USC, §7522(a)(3)), "prohibits any person from removing or rendering inoperative any emission control device or element of design installed on or in a motor vehicle or motor vehicle engine prior to its sale and delivery to an ultimate purchaser" and prohibits "any person from knowingly removing or rendering inoperative any such device or element of design after such sale and delivery to the ultimate purchaser." The visual check is an important part of the vehicle safety inspection. The commission made no changes to the rules in response to these comments.

One individual recommended that all vehicles operating in or commuting into all nonattainment areas be subject to a more stringent test and issued a corresponding "distinctive" sticker.

Vehicles within the designated I/M program areas have a distinctive bar on the vehicle's registration sticker to identify that the vehicle is registered in the program area and therefore subject to an emissions test. All 2 - 24 year old gasoline-powered vehicles registered in an I/M program area, as well as vehicles that operate more than 60 calender days per testing cycle in an I/M program area, are required to comply with emissions standards for such an area. Vehicles must comply with the safety and emissions testing program to be issued a safety certificate. As an additional enforcement mechanism, remote sensing is used to identify high-emitting vehicles operating in an I/M program area. Once a high-emitting vehicle is identified, the owner of the vehicle is instructed by written notice to bring the vehicle in to a state-certified emissions testing station for a verification emissions test and to make necessary repairs to bring the vehicle into program compliance. Vehicles registered outside the nonattainment areas are not subject to emissions testing. The commission made no changes to the rules in response to this comment.

Six individuals wanted to see obvious oil burning or ill-maintained vehicles stopped and cited when on the freeway. It was also recommended that after a citation has been issued, a five-day retractable grace period be implemented, if the motorist brings the vehicle back into compliance.

The TTC, §548.306, specifies that a motor vehicle registered in an ozone nonattainment area commits an offense if visible smoke remains suspended in the air ten or more seconds before fully dissipating. Therefore, law enforcement personnel may issue a citation to the registered owner of a vehicle that produces excessive visible smoke. A law enforcement officer who has probable cause to believe that this offense has been committed, has the authority to issue the driver of the vehicle an informative citation and explain that the registered owner of the vehicle may receive notice in the mail about the violation. 30 TAC §111.111(a)(5) states that motor vehicles shall not have visible exhaust emissions for more than ten consecutive seconds. This rule applies statewide and can be enforced by local law enforcement agencies. Implementing a five-day grace period after the citation has been issued is beyond the scope of this rulemaking. The commission made no changes to the rules in response to these comments.

One individual recommended that a program be established to find older cars without smog devices and people who disable their catalytic converter.

According to the "Rules and Regulations Manual for Operation of Official Vehicle Inspection Stations" the annual safety inspection procedures consist of a visual exhaust emissions check on 1968 and newer vehicles. The check includes inspecting the exhaust emission system to determine if it has been removed, disconnected, or altered in any manner to make it ineffective; checking the plumbing or hoses for leaks, breaks, and improper routing; and checking the air pump (air injection type) to determine if it is loose, broken, excessively cracked, frayed, or has pieces missing. The inspector also checks the catalytic converter on 1984 or later model vehicles to make sure it has not been removed or is leaking or disconnected. The commission made no changes to the rules in response to this comment.

Three individuals wanted to incorporate mandatory inspections prior to registration of the vehicle.

Incorporating mandatory inspections prior to registration of the vehicle requires legislative authority and is therefore beyond the scope of this rulemaking. Currently, motorists whose vehicle have failed the emissions test and have not complied with the I/M program requirements are denied re-registrations of the subject vehicle until the motorist has complied with the I/M program requirements. The commission made no changes to the rules in response to this comment.

ExxonMobil, LWV-TX, BCCA, and two individuals supported ASM-2 testing with integrated OBD testing in all eight counties of the HGA.

The commission appreciates the support of OBD and ASM-2 testing and agrees that emissions reductions of NO_x and VOCs are required from all eight counties for the HGA area to demonstrate ozone attainment.

The Liberty County Sheriff asked who is going to enforce the regulation?

The vehicle emissions testing program is administered under Texas state law by the commission, TxDOT, and the DPS. Vehicles registered in an I/M program area must comply with the safety and emissions testing program to be issued a safety certificate. Motorists can be issued citations by local and state law enforcement officials for driving a vehicle with an expired or invalid state inspection certificate, or for evading the emissions inspection or inspection outside of the affected area. These violations of the TTC, §548.602 (Class C misdemeanor) and §548.603 (Class B misdemeanor) are respectively punishable by a fine starting at $200 and not exceeding $2,000 for each occurrence. Violators are given notification that they must comply with the I/M program requirements. The commission, TxDOT, and DPS implement a vehicle re-registration denial enforcement element for vehicles that fail to comply with the emissions testing program.

Remote sensing is used to identify high-emitting vehicles commuting into an area and as an additional enforcement mechanism to identify high-emitting vehicles that have not complied with the program. Once a high-emitting vehicle is identified, the owner of the vehicle is instructed by written notice from the DPS to bring the vehicle into a state-certified emissions testing station for a verification emissions test and to make necessary repairs to bring the vehicle into program compliance. Failure to comply with the notice is a Class C misdemeanor. Local law enforcement officials are responsible for ensuring that vehicles operating on public roads have a valid registration sticker and safety certificate.

DPS also conducts overt and covert audits of the vehicle inspection stations.

One individual recommended sticking to the existing program.

The current TSI testing program is considered effective in identifying vehicles grossly polluting for HC or CO. However, idle testing does not allow for the measurement of NO_x because under idle modes the temperature and pressure in the combustion chambers are not high enough to produce a significant amount of measurable NO_x. In order to help the HGA nonattainment area achieve the necessary NO_x reductions, the current TSI test must be upgraded to an alternative test type, such as ASM-2 that can measure NO_x emissions, and therefore achieve significant NO_x reductions. The commission made no changes to the rules in response to this comment.

Geographic Coverage

The Sierra-Houston and seven individuals supported tougher auto emissions testing and felt that all counties should be subject to this rule and enforced statewide. LWV-TX commented that testing should be required throughout the airshed.

Expansion of the I/M program in all counties is beyond the scope of this rulemaking and may require legislative authority. However, TTC, §548.301(b) and Texas Health and Safety Code, §382.037(c) allow the commission to establish by rule an I/M program in any county provided the county and its most populous municipality adopt a resolution requesting such a program. The commission has not received any such resolutions to allow for implementation statewide. The commission made no changes to the rules in response to these comments.

One individual recommended tailpipe testing for all vehicles registered by residences of the following cities: Dallas, Garland, Richardson, Carrollton, Coppell, Fort Worth, Grapevine, Southlake, Burleson, Mansfield, Pearland, Houston, Katy, Missouri City, Stafford, and Friendwood.

Residents of Dallas (Collin, Dallas, Denton, Kaufman, and Rockwall Counties); Garland (Collin, Dallas, and Rockwall Counties); Richardson (Collin and Dallas Counties); Carrollton (Collin, Dallas, and Denton Counties); Coppell (Dallas and Denton Counties); Fort Worth (Tarrant and Denton Counties); Grapevine (Dallas, Denton, and Tarrant Counties); Southlake (Denton and Tarrant Counties); Burleson (Johnson and Tarrant Counties); Mansfield (Ellis, Johnson, and Tarrant Counties); Pearland (Brazoria and Harris Counties); Houston (Fort Bend, Harris, and Montgomery Counties); Katy (Fort Bend, Harris, and Waller Counties); Missouri City (Fort Bend and Harris Counties); Stafford (Fort Bend and Harris Counties); and Friendswood (Galveston and Harris Counties) are all in affected counties and will be required to have emissions tests conducted on their registered vehicles. The commission made no changes to the rules in response to this comment.

One individual recommended tailpipe testing for residents in Plano, the Colony, Flower Mound, Lewisville, Corinth, Denton, Lake Dallas Shores, Dickinson, League City, New Caney, Porter, The Woodlands, and Oak Ridge North prior to acquisition of new plates for: 1) diesel-powered motor vehicles; 2) gasoline vehicles model years 1979 - 1994 registered with new plates starting in 2002; 3) gasoline vehicles model years 1995 - 2002 which are repaired after collisions; and 4) out-of-state residents receiving Texas license plates.

All 2 - 24 year old gasoline-powered vehicles registered in the program area must comply with the safety and emissions testing program to be issued a safety certificate. A phased approach to implementing the I/M program has been adopted by the commission which will include all of the cities listed.

Currently, diesel-powered vehicles are not included in the I/M program. These vehicles make up a small percentage (approximately 3%) of the vehicle population. Due to less standardization in diesel vehicles, more technological development is needed before testing is initiated. The commission is, however, researching the future feasibility of diesel testing.

All vehicles are tested annually whether in an accident or not. In addition, most collisions do not necessarily impair vehicle emissions equipment. Motorists who relocate to Texas from out-of-state must pass a safety inspection prior to registering their vehicle in Texas. Also, if the motorist resides in an I/M program area, they are required to comply with the safety and emissions requirements before receiving Texas plates.

The commission made no changes to the rules in response to these comments.

Other Issues

One individual commented that Texas consider alternative means, such as those taken recently by Florida, of dealing with air pollution that do not interfere with every individual.

The air quality in the nonattainment areas in Florida has improved enough to have the areas classified as attainment areas in 1994. The vehicle emissions testing program in Florida was a voluntary measure by the Florida Legislature to ensure continued compliance with the air quality standards. Later, Florida's state implementation plan indicated that the state could demonstrate continued compliance with the air quality standards without using tailpipe testing as a control strategy. Therefore, the Florida Legislature had the option of eliminating their emissions testing program. Since the Houston area cannot demonstrate compliance with the air quality standards, vehicle emissions testing must continue to be one of the many control strategies used in Texas. The commission made no changes to the rules in response to this comment.

Three individuals felt that tailpipe testing would do no good.

A major contributor to air pollution is the exhaust from cars and trucks. All over Texas vehicles contribute as much as half of the harmful air emissions that create pollution. One vehicle in bad repair can produce 28 times as much pollution as one vehicle in good repair. Even though vehicle manufacturers are required to install emissions controls on all vehicles, if the vehicles are not being properly maintained, the emissions control devices will be less effective. The emissions testing program tests vehicles 2 - 24 years old. These vehicles account for the vast majority of vehicles on the road and the vehicle miles traveled, which have a direct correlation to the impact on air quality. The amount of emissions reduction benefits is not only based on repairing failed vehicles, but also from vehicles being properly maintained because they are subject to emissions testing. As OBD testing only applies to model year 1996 and newer vehicles, there is a need for a tailpipe test to identify high NO_x emissions from older vehicles. The commission made no changes to the rules in response to this comment.

GEHC supported tougher programs for testing vehicles emissions but not until obvious changes have taken place to stop grandfathered and industrial pollution.

The commission has made no change in response to the comments. The implementation of the vehicle emissions program is one of many programs being adopted to reduce ozone. The commission's plan to reduce ozone pollution also includes programs designed to achieve significant reductions from industrial and manufacturing facilities. Combined, these programs provide the best plan for achieving the necessary reductions without overburdening any one sector of the community.

The adopted rules that apply to facilities, for example the Chapter 117 NO_x requirements and the Chapter 115 VOC requirements, apply to both permitted and non-permitted ("grandfathered") sources in HGA. The commission agrees that it is appropriate to pursue cost-effective measures to reduce pollution; however, any such measures must be within the statutory authority of the commission. The TCAA does not authorize the commission to require grandfathered sources to obtain permits in order to operate, or to prohibit operation of those sources. A grandfathered facility is one that existed at the time the Texas Legislature amended the TCAA in 1971. These facilities were not required to comply with (i.e., were grandfathered from) the then new requirement to obtain permits for construction activities. Whenever a grandfathered facility is modified (as that term is defined in the TCAA) then it is required to comply with the TCAA permitting requirements in order to be authorized to construct and operate that modification. If a grandfathered facility has never been modified, it continues to be authorized by the TCAA to operate without a permit. Further, the definition of "modification" specifically excludes changes to facilities that are authorized by an exemption, i.e., any facility, including a grandfathered facility, can make a change using a commission exemption (now permit by rule) and this change is not considered to be a modification that would trigger the permitting requirements of the TCAA. During the 76th Texas Legislative Session in 1999, the issue of grandfathered sources was addressed by two different legislative programs. Senate Bill 766 was passed which provided a framework for a voluntary permitting program for grandfathered sources under the TCAA, and SB 7 which requires mandatory permitting and emission reductions from electric generating facilities. The commission continues to pursue enforcement action against companies who are not in compliance with the permitting requirements of the TCAA. However, Senate Bill 766 does provide for amnesty from enforcement for facilities eligible to participate in the voluntary emission reduction permit program as long as a permit application is received before the TCAA deadline of September 1, 2001.

Brazoria CCC commented that the impact of the emissions testing and denial of re-registration of vehicles who do not pass the test has a disparate impact upon the economically disadvantaged citizens. The commenter stated that this denial of the right to use a vehicle is a taking of property without a hearing and without compensation. The commenter stated that the procedures contained in the SIP constitute an unlawful delegation of legislative authority to an administrative agency.

Although it is not clear what, if any, legal standard the commenter alleges the commission would violate in adopting the rules, they state that the rules would "disproportionately impact" economically disadvantaged. This could be a reference to Title VI of the Civil Rights Act of 1964. In order for the commission to be shown in violation of Title VI, a disproportionately negative impact to minorities must be shown. The commission maintains that the rules as adopted will not have a disparate impact on persons based on race, color, or national origin. The basis for the rules is protection of human health and the environment, and the reduction in overall motor vehicle emissions is anticipated to provide reductions in the formation of ozone in the area. As for potential negative impacts of the rules, these are clearly borne equally by all drivers governed by the rules without any differentiation by race, color, or national origin.

The commission understands that vehicle repairs can be costly. In order to assist the public, the vehicle emissions testing program includes two waiver options: the minimum expenditure waiver and the individual vehicle waiver. The minimum expenditure waiver is available to those who have made repairs to their vehicle within the established criteria and met the dollar limits established by the EPA rule. The individual vehicle waiver is for those who cannot meet emissions standards despite every reasonable effort by the motorist. In addition to these two waivers, the low-income time extension is available for those who can demonstrate a financial inability to either afford adequate repairs or to meet the applicable minimum expenditure waiver amount. The waivers and extension are ways to ensure that motorists who are making a "good faith" effort to comply with the I/M program requirements do not incur excessive repair costs, are not excessively inconvenienced, or are not denied re-registration of their vehicle.

With regard to the idea that the program amounts to a taking of a vehicle, the commission disagrees with the commenter. Legally, this program is no different than the requirement that all drivers must carry liability insurance in order to operate their vehicle. While both programs set conditions which must be met before operating a motor vehicle, the state's police power to protect the health and safety of the general public outweighs the burden on the individual driver. Neither program represents a taking of a vehicle without hearing or just compensation.

Finally, the I/M program is not an unlawful delegation of legislative authority to an administrative agency. The Texas Legislature has defined and redefined the parameters of an authorized I/M program over the past decade. The current specific state authorization is found in the TCAA, §§382.037 - 382.038. Additionally, the directive of the legislature to adopt a program as required by federal law, TCAA, §382.037(c)(1), was written in light of the specific federal program requirements found in FCAA, §182(c)(3) and in EPA rules at 40 CFR Part 51, Subpart S. The I/M program has been lawfully authorized and the implementation of the program lawfully delegated to the commission.

Brazoria CCC commented that the remote sensing component of the program is a violation of the United States Constitution because it is covert surveillance of citizens without probable cause. Brazoria CCC stated that the proposed program violates the United States Constitution as it pertains to criminalizing innocent behavior and not affording the presumption of innocence, as well as proposing enforcement tactics that clearly violate the safeguards of probable cause in the criminal justice system.

The commission disagrees with the commenter that the remote sensing component of the program amounts to an illegal search. The remote sensing components detects emissions of vehicles which are operating on the public roadway in plain view and therefore is not a search. There is no unlawful entry into private domain and the vehicle is not stopped at the time of the test so there is no seizure. Further, as case law indicates, there is a reduced expectation of privacy associated with motor vehicles and therefore only probable cause is required to search an automobile.

The commission disagrees with the commenter's assertion that the program criminalizes innocent behavior. It is not a crime to be detected as a high-emitter by remote sensing equipment so there is no presumption of guilt or innocence. In the event that a vehicle detected as a high-emitter, the operator is required to bring the vehicle in for an emission test. The operator may choose to repair the vehicle before bringing it for a test, in which case a clean test will mean there are no further conditions upon that operator. If the operator then fails the emission test, the operator must either repair the vehicle or qualify for a waiver within a certain period of time. It is only the operator who does not bring the vehicle in at all or who does not follow-up after a failed test who is subject to penalty under the program. In these cases, probable cause has clearly been demonstrated and due process is provided through the enforcement phase.

One individual commented that the proposed I/M program was illegal, unconstitutional, and unenforceable. In addition, he wanted to know if he will be considered a criminal for driving a vehicle that cannot pass a tailpipe test.

The FCAA Amendments of 1990 require vehicle emission testing in all communities where ozone levels exceed federal health standards which have been classified as moderate or above nonattainment areas. Senate Bill 1856, passed by the Texas Legislature, 75th Session, 1997, gave the commission the authority to establish the current I/M program.

The vehicle emissions testing program is administered under Texas state law by the commission and the DPS. The TTC, §548.301, states that the commission shall establish a motor vehicle emissions inspection and maintenance program for vehicles as required by any law of the United States or the state's air quality state implementation plan. The TCAA,

§382.037, specifies that the commission by rule may require emissions-related inspection and maintenance of land vehicles, including testing exhaust emissions, examining emission control devices and systems, verifying compliance with applicable standards, and other requirements as provided by federal law or regulation. Motorists are issued citations by local and state law enforcement officials for driving a vehicle with an expired or invalid state inspection certificate, or for evading the emissions inspection or inspection outside of the affected area. These violations of the TTC, §548.602 (Class C misdemeanor) and §548.603 (Class B misdemeanor) are respectively punishable by a fine starting at $200 and not exceeding $2,000 for each occurrence. The owner will be subject to an additional citation every time the vehicle is driven. Violators are given notification that they must comply with the I/M program requirements.

Although it is a criminal offense to drive a vehicle without a proper safety and emissions certificate, it is not a criminal offense to drive a vehicle that has not passed the emissions test if the vehicle has received a waiver or extension.

The commission disagrees with the commenter's statement that the I/M program is unconstitutional for all the reasons stated in response to comments regarding unlawful taking, due process, unlawful delegation.

The commission made no changes to the rules in response to these comments.

Baker Botts commented that it generally supports the ongoing efforts by the commission to develop a SIP that is technologically achievable, economically reasonable, and legally approvable. Baker Botts, BCCA, ExxonMobil, Harris County Judge Robert Eckels, Phillips 66, TCC, and an individual commented that the commission should incorporate into the SIP a greater level of reductions from federally preempted sources and stated that EPA-regulated sources account for about 40% of the NO_x emissions in the HGA. The commenters stated that the EPA issued a number of regulations for some federally preempted sources, such as land-based spark engines, marine, recreational and land-based diesel engines, aircraft and locomotive engines, well after the FCAA deadlines, and that the EPA recently strengthened rules for on-road and non-road vehicles and fuels, such as low sulfur gas and diesel, Tier II motor vehicles, heavy-duty highway vehicle standards, and non-road Tier II/Tier III heavy-duty engine standards. The commenters stated that delays in implementing these rules have prompted the commission to propose technically and economically infeasible emission reductions from sources in HGA that the state has authority to regulate to make up for the missing federal reductions. The commenters stated that these delays have forced the commission to propose expensive regional fuels and significant use restriction regulations. The commenters stated that the commission and the EPA can ensure an equitable distribution of the compliance burdens necessary to meet mandated air quality improvement in HGA only by allowing the SIP to capture anticipated emission reductions from federally preempted sources. Baker Botts noted that the EPA demonstrated a willingness to assume responsibility for a portion of emission reductions by creating a process in Los Angeles called a "public consultative process," that would resolve issues related to emissions from national and international sources, and that the EPA has also provided flexibility in obtaining offsets by allowing states to provide offsets to refiners based on emission reductions that the EPA projected would result from mobile sources using Tier II gasoline. Baker Botts suggested that this same sort of prospective crediting should be used to develop a more rational HGA SIP, and that the EPA should allow the commission to credit in the SIP the prospective emission reductions that will result from implementation of the Tier II gasoline rule and from other federally preempted sources. Finally, Baker Botts cited two cases wherein the District of Columbia Circuit has approved the EPA's flexibility with respect to statutory deadlines under the FCAA when the EPA has failed to meets its own deadlines, and this failure was deemed to upset the balanced federal/state responsibilities under the FCAA. ExxonMobil commented that it supports the commission and the EPA crediting the HGA SIP with an additional 60 tpd of federally preempted emission reductions that will occur over the next ten years. Harris County Judge Robert Eckels commented that the commission should work with the EPA to accelerate the implementation schedule for federally preempted emissions so that at least one-half of the related emission reductions are achieved by 2007, and that as a part of this process, the commission should delineate federal assignments detailing the engine standards and emission reductions necessary to achieve real and sustainable pollution reductions.

The commission agrees with the commenters that emission reductions from federally preempted sources would provide benefits for the HGA SIP demonstration, and the inability of the commission to regulate certain source categories has necessitated the use of other ozone control strategies. However, the commission understands that the EPA SIP approval process does not provide a mechanism for credit for emission reductions that occur after the attainment date. The commission understands that EPA is not currently considering accelerating implementation schedules for existing federal rules. The commission is working with EPA to determine the availability of SIP credit for many non-traditional control strategy mechanisms, like economic incentive programs and flexibility for preempted source categories. Additionally, the commission is working with EPA to determine an appropriate federal contribution credit available for the HGA SIP.

BCCA, ExxonMobil, and Phillips commented that the commission has failed to follow the requirements for adopting a major environmental rule as required by Texas Government Code, §2001.0225 (i.e. no cost benefit analysis performed; no draft impact analysis performed; no description of why identified reasonable alternative were rejected; and no final RIA performed). BCCA and Phillips commented that the proposed rule meets the definition of a major environmental rule and that the RIA requirements of Texas Government Code, §2001.0225 are triggered because the proposed rule exceeds standards set by federal law and exceeds an express requirement of state law. BCCA further commented that the commission's efforts to avoid an RIA by asserting that the proposed rules are exempt from the RIA requirements because federal law mandates the rules is legally flawed and may render the rules invalid.

The commission disagrees with the commenters that the proposed rules meet the definition of a major environmental rule and that its interpretation of the exemption for federally mandated standards is legally flawed. While the rules may require significant capital investments by inspection station owners, the fee established under the rules should offset most, if not all of the costs. Additionally, whether a rule is a "major environmental rule" alone is not enough to trigger the RIA requirements. Texas Government Code, §2001.0225 only applies to a major environmental rule adopted by a state agency, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

This rulemaking action does not meet any of these four applicability requirements, and is adopted in substantial compliance with the RIA requirements. Texas Government Code, §2001.035. These rules do not exceed an express standard set by federal law because the I/M requirements are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409 and the requirement for a severe nonattainment are to have an I/M program under 42 USC, §7511a(d). Title 42 USC, §7410 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. Failure to develop control strategies to demonstrate attainment can result in federal sanctions. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA.

This conclusion is supported by the legislative history for Texas Government Code, §2001.0225. During the 75th Legislative Session, SB 633 amended the Texas Government Code to require agencies to perform an RIA of certain rules. The intent of SB 633 was to require agencies to conduct a RIA of 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. 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. Because of the ongoing need to address nonattainment demonstrations required by federal law, the commission routinely proposes and adopts SIP rules. If each rule proposed for inclusion in the SIP was incorrectly considered as exceeding federal law, every SIP rule would require the full RIA contemplated by SB 633. This result would be inconsistent with the cost estimates and fiscal notes prepared by the commission and by the LBB. 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 meet the requirements under §2001.0225(a). 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. In other words, the proposed rules are intended to meet federal and state law, and do not go above and beyond what is required to meet federal or state statutes.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp,* 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue,* 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.,* 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ); *Cf. Humble Oil & Refining Co. v. Calvert,* 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd,* Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor,* 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.,* 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the APA by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore, in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, 382.017, 382.019, 382.037 - 382.038, and 382.039 authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

BCCA, ExxonMobil, and Phillips commented that the rule was proposed without an adequate takings impact assessment. The commenters stated that Section 2007 of the Texas Government Code requires an agency to prepare a written takings impact assessment when proposing a rule. They further stated that the assessment must describe the purpose of the proposed action; determine whether engaging in the proposed action will constitute a taking; and describe reasonable alternative actions that could accomplish the specified purpose and explain whether these alternatives actions also would constitute takings. BCCA and ExxonMobil stated that guidelines from the attorney general direct an agency to carefully review governmental actions that have a significant impact on the owner's economic interest. Finally, BCCA commented that commission did not explain why the rule was reasonably taken to meet the federal requirement and therefore does not qualify for the exemption claimed. BCCA stated that this rule requires more than is necessary to meet the federal requirement.

The primary reason the commission determined that these rules did not constitute a takings under Texas Government Code, Chapter 2007 is that they will not burden private real property. These rules apply to motor vehicles and to equipment required at vehicle inspection stations, neither of which are real property or appurtenance thereto.

In its analysis, the commission also found that the rules are exempt from Texas Government Code, Chapter 2007 pursuant to §2007.003(b)(4) because they are reasonably taken to fulfill an obligation mandated by federal law. The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. Additionally, these rules implement an I/M program which is specifically required by 42 USC, §7511a(d). This rulemaking therefore meets the requirements of §2007.003(b)(4). Although the rule amendments 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 significantly advance the health and safety purpose and therefore meet the requirement of §2007.003(b)(13). For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

BCCA, ExxonMobil, and Phillips66 commented that the small and micro-business assessment was inadequate as provided. Specifically, the commenters stated that the commission failed to consider the costs of compliance for small and micro-businesses, and that the proposal did not adequately compare of the cost of compliance for small businesses to the cost of compliance for the largest businesses affected by the proposed rules. BCCA noted that none of the Plan's small and micro-business assessments applied the mandated cost comparison standards, even where the commission acknowledged "significant" impact. BCCA commented that the commission either restated the costs of compliance it identified in the analyses of public benefits and costs, or concluded that it cannot determine the cost to small businesses. Finally, BCCA noted that it is impossible for the public to provide comment on whether the commission adequately considered the effect of the rule on small business because the commission did not publish the information required by Texas law.

The agency has estimated, to the extent possible, the costs to small businesses and has determined that the cost depends more upon either the number of motor vehicles operated by the business or, for inspection stations, the number of vehicle inspection lanes, and that it is not dependent upon the number of employees, hours of labor, or amount of sales income. Some small businesses have only one motor vehicle while others have large fleets. Large businesses vary in the same way. The size of the fleet is not dependent upon the size of the business. Additionally, for inspection stations, the number of lanes dedicated to inspections will determine the amount of test equipment needed. The commission has provided the estimated cost per vehicle and per piece of testing equipment and argues that this is the only meaningful way to provide sufficient notice of the cost to small business and therefore that it meets the objective of Texas Government Code, Chapter 2006. This assertion is supported by the fact that no small businesses provided comments which include cost of compliance in terms of the number of employees, hours of labor, or amount of sales income.

BCCA, ExxonMobil, and Phillips 66 stated that the proposed rules did not include adequate notice as required under Texas Government Code, §2002.024. The commenters stated that Texas Government Code, §2001.024, requires adequate notice of a proposed rule, including information about its public benefits and costs. The commenters stated that adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule, and that courts have considered notice "adequate" only if: interested persons can confront the agency's factual suppositions and policy preconceptions; and the agency provides interested parties the opportunity to challenge the underlying factual data relied upon by the agency. The commenters asserted that in proposing the rules, the commission failed to provide interested parties with sufficient information to constitute adequate notice.

BCCA stated that the rule proposal preamble appears short of adequate notice because the cost estimates were "dramatically underestimated" and added that the commission provided no bases for estimating that only 10% of the current stations in Harris County would need to purchase new equipment.

The commenters stated that they had identified a number of critical gaps in the underlying factual data, methodology, and analysis in support of the proposed rules. The commenters asserted that the proposal included insufficient information and analysis regarding costs and impacts. The commenters asserted that the commission has not adequately responded to requests for additional information from stakeholders. The commenters stated that the following requests for information were outstanding: information regarding the modeling of emissions; information regarding the corrected emissions inventory database; and information supporting the estimated costs of control. The commenters stated that this information is necessary in order to comment effectively on the proposed rules and that data gaps in the proposal hindered effective comment.

The commission disagrees with the commenters and has made no change in response to these comments. Texas Government Code, §2001.024 requires of the notice of a proposed rule include certain information. Subsection (a)(5) requires that the notice state the public benefits expected as a result of the adoption of the proposed rule and the probable economic cost to persons required to comply with the rule. Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn,* 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of the proposed rules. The commission received intelligent comments which were substantial in both number and in scope, regarding the costs as well as the benefits. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

BCCA's statements that the costs were "dramatically underestimated" did not state how that conclusion was reached. Mere disagreement with cost estimates does not render notice inadequate. BCCA did not state that why they disagreed with the commission's 10% estimate for stations in Harris County. In fact, the commission based this estimate on knowledge of which machines are in use under the current program and information from the vendor indicating whether those machines can be upgrade or must be replaced altogether. To simply state that the proposal failed to provide sufficient information does not provide the commission with sufficient information to propose changes or alternative strategies. The commenters did not say how the notice is insufficient, merely that it is insufficient. Nevertheless, the commission has reviewed the notice and has determined it is adequate.

Similarly, the comments which state there are critical gaps did not identify what those gaps are or how that results in inadequate notice. The commission is unaware of any requests for additional information to which it was not completely responsive.

BCCA, ExxonMobil, and Phillips 66 stated that the proposed rules did not include the local employment impact statement required under Texas Government Code, §2001.022. The commenters stated that Texas Government Code, §2001.022, requires the commission to determine whether the rule proposal has the potential to affect a local economy before proposing the rule for adoption. The commenters stated that if answered affirmatively, the commission must request the Texas Employment Commission prepare a local employment impact statement describing in detail the probable effect of the rule on employment in each geographic area affected by the rule for each year of the first five years that the rule will be in effect. The commenters further asserted that the commission failed to make the required initial determination and ignored the potential for the proposal to adversely affect the local economy. The commenters stated that a local employment impact statement should have been requested and prepared in advance of the proposal.

The commission agrees with the commenters that the proposed rules may affect a local economy, however, does not agree that it is the responsibility of the commission to provide the local employment impact analysis. The APA requires state agencies to determine whether a rule may affect a local economy before proposing a rule for adoption. If the agency determines that a proposed rule may affect a local economy, the agency must send a copy of the proposed rule and other information to the Texas Workforce Commission (Workforce Commission) before the agency files notice of the proposed rule with the secretary of state. The APA requires the Workforce Commission to prepare a local employment impact statement for proposed rules, if a state agency requests the statement. The commission determined that the proposed rules might affect a local economy, and sent the proposed rules and other requested information to the Workforce Commission. The commission received a letter from the Workforce Commission, indicating that the Workforce Commission did not have the ability to determine the potential local employment impacts from the proposed rules.

STATUTORY AUTHORITY

The amendments are adopted under Texas Water Code (TWC), §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC. The amendments are also adopted under the Texas Health and Safety Code, TCAA, §382.011, which provides the commission the authority to control the quality of the state's air; §382.012, which provides the commission the authority to prepare and develop a general, comprehensive plan for the control of the state's air; §382.017, which provides the commission the authority to adopt rules consistent with the 0policy and purposes of the TCAA; §382.019, which provides the commission the authority to adopt rules to control and reduce emissions from engines used to propel land vehicles; §382.037 through §382.038, which provide the commission the authority by rule to establish, implement, and administer a program requiring emissions-related inspections of motor vehicles to be performed at inspection facilities consistent with the requirements of the FCAA; and §382.039, which provides the commission the authority to coordinate with federal, state, and local transportation planning agencies to develop and implement transportation programs and other measures necessary to demonstrate and maintain attainment of NAAQS and to protect the public from exposure to hazardous air contaminants from motor vehicles.

§114.50. Vehicle Emissions Inspection Requirements.

(a) Applicability. The requirements of this section and those contained in the revised Texas Inspection and Maintenance (I/M) State Implementation Plan (SIP) shall be applied to all gasoline-powered motor vehicles 2-24 years old and subject to an annual emissions inspection, beginning with the first safety inspection. Currently, military tactical vehicles, motorcycles, diesel-powered vehicles, dual-fueled vehicles which cannot operate using gasoline, and antique vehicles registered with the Texas Department of Transportaiton are excluded from the program. Safety inspection facilities and inspectors certified by the Texas Department of Public Safety (DPS) shall inspect all subject vehicles, in the following program areas in accordance with the following schedule.

(1) All vehicles registered and primarily operated in Dallas, Tarrant, Harris, and El Paso Counties shall be tested using a two-speed idle (TSI) test through April 30, 2002.

(2) This paragraph applies to all vehicles registered and primarily operated in the Dallas/Fort Worth (DFW) program area.

(A) Beginning May 1, 2002, all 1996 and newer model year vehicles registered and primarily operated in Collin, Dallas, Denton, and Tarrant Counties equipped with on-board diagnostic (OBD) systems shall be tested using EPA-approved OBD test procedures. If OBD data cannot be collected from the vehicle, an EPA-approved tail-pipe emissions test will be used.

(B) Beginning May 1, 2002, all pre-1996 model year vehicles registered and primarily operated in Collin, Dallas, Denton, and Tarrant Counties shall be tested using an acceleration simulation mode (ASM-2) test, or a vehicle emissions test that meets SIP emissions reduction requirements and is approved by the EPA.

(3) This paragraph applies to all vehicles registered and primarily operated in the extended DFW (EDFW) program area.

(A) Beginning May 1, 2003, all 1996 and newer model year vehicles registered and primarily operated in Ellis, Johnson, Kaufman, Parker, and Rockwall Counties equipped with OBD systems shall be tested using EPA-approved OBD test procedures. If OBD data cannot be collected from the vehicle, an EPA approved tail-pipe emissions test will be used.

(B) Beginning May 1, 2003, all pre-1996 and older model year vehicles registered and primarily operated in Ellis, Johnson, Kaufman, Parker, and Rockwall Counties shall be tested using an ASM-2 test, or a vehicle emissions test that meets SIP emissions reduction requirements and is approved by the EPA.

(4) This paragraph applies to all vehicles registered and primarily operated in the Houston/Galveston (HGA) program area.

(A) Beginning May 1, 2002, all 1996 and newer model year vehicles registered and primarily operated in Harris County equipped with OBD systems shall be tested using EPA-approved OBD test procedures. If OBD data cannot be collected from the vehicle, an EPA approved tail-pipe emissions test will be used.

(B) Beginning May 1, 2002, all pre-1996 model year vehicles registered and primarily operated in Harris County shall be tested using an ASM-2 test, or a vehicle emissions test that meets SIP emissions reduction requirements and is approved by the EPA.

(C) Beginning May 1, 2003, all 1996 and newer model year vehicles equipped with OBD systems and registered and primarily operated in Brazoria, Fort Bend, Galveston, and Montgomery Counties shall be tested using EPA-approved OBD test procedures. If OBD data cannot be collected from the vehicle, an EPA approved tail-pipe emissions test will be used.

(D) Beginning May 1, 2003, all pre-1996 and newer model year vehicles registered and primarily operated in Brazoria, Fort Bend, Galveston, and Montgomery Counties shall be tested using the ASM-2 test procedures, or a vehicle emissions test that meets SIP emissions reduction requirements and is approved by the EPA.

(E) Beginning May 1, 2004, all 1996 and newer model year vehicles equipped with OBD systems and registered and primarily operated in Chambers, Liberty, and Waller Counties shall be tested using EPA-approved OBD test procedures. If OBD data cannot be collected from the vehicle, an EPA-approved tail-pipe emissions test will be used.

(F) Beginning May 1, 2004, all pre-1996 model year vehicles registered and primarily operated in Chambers, Liberty, and Waller Counties shall be tested using an ASM-2 test, or a vehicle emissions test that meets SIP emissions reduction requirements and is approved by the EPA.

(G) If Chambers, Liberty, and Waller Counties and their respective largest municipality submit by May 1, 2002, individually or collectively, a resolution that is approved by the commission and EPA as an alternative air control plan, then subparagraphs (E) - (F) of this paragraph are not required. The resolution should provide a control plan that will provide modeled reductions of volatile organic compounds and nitrogen oxides equivalent to the reductions that have been modeled for these counties through the implementation of the I/M program. In determining approvability of a plan, the commission will consider federal I/M program requirements.

(5) This paragraph applies to all vehicles registered and primarily operated in the El Paso program area.

(A) Beginning May 1, 2002, all 1996 and newer model year vehicles equipped with OBD systems shall be tested using EPA-approved OBD test procedures. If OBD data cannot be collected from the vehicle, an EPA-approved tail-pipe emissions test will be used.

(B) Beginning May 1, 2002, all pre-1996 vehicles shall be tested using a TSI test.

(b) Control requirements.

(1) No person or entity may operate, or allow the operation of, a motor vehicle registered in the DFW, EDFW, HGA, and El Paso program areas which does not comply with:

(A) all applicable air pollution emissions control related requirements included in the annual vehicle safety inspection requirements administered by DPS, as evidenced by a current valid inspection certificate affixed to the vehicle windshield; and

(B) the vehicle emissions inspection and maintenance requirements contained in this subchapter.

(2) All federal government agencies shall require a motor vehicle operated by any federal government agency employee on any property or facility under the jurisdiction of the agency and located in a program area to comply with all vehicle emissions I/M requirements contained in the revised Texas I/M SIP. Commanding officers or directors of federal facilities shall certify annually to the executive director, or appointed designee, that all subject vehicles have been tested and are in compliance with the Federal Clean Air Act (42 United States Code, et seq.). This requirement shall not apply to visiting agency, employee, or military personnel vehicles as long as such visits do not exceed 60 calendar days per year.

(3) Any motorist in the DFW, EDFW, HGA, or El Paso program areas who has received a notice from an emissions inspection station that there are recall items unresolved on their motor vehicle, should furnish proof of compliance with the recall notice prior to the next vehicle emissions inspection. The motorist may present a written statement from the dealership or leasing agency indicating that emissions repairs have been completed as proof of compliance.

(4) A motorist whose vehicle has failed an emissions test may request a challenge retest through DPS. If the retest is conducted within 15 days of the initial inspection, the retest is free.

(5) A motorist whose vehicle has failed an emissions test and has not requested a challenge retest or has failed a challenge retest must have emissions-related repairs performed and must submit a properly completed Vehicle Repair Form (VRF) in order to receive a retest, a minimum expenditure waiver, or a parts availability time extension.

(6) A motorist whose vehicle is registered in the DFW, EDFW, HGA, or El Paso program areas and has failed an on-road test administered by the DPS shall:

(A) submit the vehicle for an out-of-cycle vehicle emissions inspection within 30 days of written notice by the DPS; and

(B) satisfy all inspection, extension, or waiver requirements of the vehicle emissions I/M program contained in the revised Texas I/M SIP.

(7) State, governmental, and quasi-governmental agencies which fall outside the normal registration or inspection process shall comply with all vehicle emissions I/M requirements contained in the Texas I/M SIP for vehicles primarily operated in I/M program areas.

(c) Waivers and extensions. A motorist may apply to the DPS for a waiver or an extension as specified in §114.52 of this title (relating to Waivers and Extensions for Inspection Requirements), which defer the need for full compliance with vehicle emissions standards for a specified period of time after failing a vehicle emissions inspection.

(d) Prohibitions.

(1) No person may issue or allow the issuance of a vehicle inspection report (VIR), as authorized by DPS, unless all applicable air pollution emissions control related requirements of the annual vehicle safety inspection and the vehicle emissions I/M requirements and procedures contained in the revised Texas I/M SIP are completely and properly performed in accordance with the rules and regulations adopted by DPS and the commission. Prior to taking any enforcement action regarding this provision, the commission shall consult with DPS.

(2) No person may allow or participate in the preparation, duplication, sale, distribution, or use of false, counterfeit, or stolen safety inspection certificates, VIRs, VRFs, vehicle emissions repair documentation, or other documents which may be used to circumvent the vehicle emissions I/M requirements and procedures contained in the revised Texas I/M SIP.

(3) No organization, business, person, or other entity may represent itself as an emissions inspector certified by the DPS, unless such certification has been issued under the certification requirements and procedures contained in the Texas Transportation Code, §§548.401 - 548.404.

(4) No person may act as or offer to perform services as a Recognized Emissions Repair Technician of Texas, (as designated by DPS), without first obtaining and maintaining DPS recognition.

§114.52. Waivers and Extensions for Inspection Requirements.

(a) Applicability. The waivers and extensions apply to any motorist who can satisfy the conditions of a specific waiver or extension. Applications must be made to the Department of Public Safety (DPS). For the minimum expenditure waiver, individual vehicle waiver, and parts availability time extension, the motorist may apply only once during each testing cycle. For the low income time extension, the motorist may apply every other test cycle.

(b) Minimum expenditure waiver. A motorist shall use any available warranty coverage to obtain needed repairs before expenditures shall be used in calculating the minimum repair expenditures to qualify for a minimum expenditure waiver, unless the warranty remedy has been denied in writing from the manufacturer or authorized dealer. A motorist may not use or attempt to use expenditures for tampering-related repairs in calculating the minimum repair expenditures to qualify for a minimum expenditure waiver. A minimum expenditure waiver shall be valid for the remaining portion of the testing cycle. Tampering includes, but is not limited to, engine modifications, emissions system modifications, or fuel-type modifications disapproved by the Texas Natural Resource Conservation Commission or EPA. A minimum expenditure waiver may be granted in accordance with the following conditions:

(1) The applicant must have a valid retest Vehicle Inspection Report (VIR), a valid Vehicle Repair Form (VRF), and the vehicle must have failed a retest after all qualifying repairs. Qualifying repairs must meet the following conditions.

(A) The minimum expenditure waiver in any program area shall be at least $450 or that amount adjusted by the Consumer Price Index.

(B) All qualifying repairs shall be performed by a Recognized Emissions Repair Technician of Texas (as designated by DPS) in order to count labor cost and/or diagnostic costs.

(C) Qualifying repairs must be directly applicable to the cause for the test failure (repairs conducted up to 60 days prior to the initial test may count toward the waiver amount).

(D) When repairs are not performed by a Recognized Emissions Repair Technician of Texas, only the purchase price of parts, applicable to the failure, qualify as a repair expenditure for the minimum expenditure waiver.

(2) The motorist provides to the DPS an original retest VIR, a properly completed VRF, and an original itemized receipt indicating the emissions-related repairs performed. If labor and/or diagnostic charges are being claimed toward the minimum expenditure, the VRF shall be completed by a Recognized Emissions Repair Technician of Texas.

(c) Low income time extension. A low income time extension may be granted in accordance with the following conditions.

(1) A motorist must supply proof that the subject vehicle failed the initial emissions inspection test in the form of an original failed vehicle inspection report.

(2) A motorist shall provide proof in writing to the DPS that the registered vehicle owner(s) meet(s) the following conditions:

(A) the low income time extension applicant is the owner of the vehicle that has failed an inspection and maintenance (I/M) test;

(B) the vehicle has not been granted a low income time extension waiver in the previous inspection cycle; and

(C) the applicant meets one of the following:

(i) the applicant receives financial assistance from the Texas Department of Human Services (subject to approval by the director of DPS); or

(ii) the applicant's adjusted gross income is within the current federal poverty income guidelines;

(D) the applicant shows proof of conformity with paragraph (2)(C) of this subsection by providing to the DPS one of the following, which the applicant certifies are true and correct:

(i) a federal income tax return; or

(ii) other documentation authorized by the director of the DPS.

(3) After a motorist receives an initial low income time extension, the vehicle must pass an emissions test prior to receiving another low income time extension or any waiver or extension.

(d) Parts availability time extension. The parts availability time extension does not exempt the vehicle from the compliance requirements of the I/M program but merely extends the period for compliance. By the end of the time extended, the vehicle must be repaired, retested, and receive a passing VIR or comply with paragraph (4) of this subsection. Only one parts availability time extension is allowed in each test cycle for each vehicle. A parts availability time extension may be granted in accordance with the following conditions.

(1) The motorist can document that emissions-related repairs cannot be completed before the expiration of the safety inspection certificate or before the 30-day period following an out-of-cycle inspection because the repairs require an uncommon part.

(2) The motorist shall provide to the DPS an original VIR indicating that the vehicle failed the emissions test and an original itemized documentation by a Recognized Emissions Repair Technician of Texas, indicating parts ordered by name; description and catalog number; order number; sources of parts, including addresses and phone numbers; and expected delivery and installation dates of uncommon parts before a parts availability time extension can be issued.

(3) The motorist shall return the motor vehicle to the DPS for a retest and verification of repairs upon completion of the repairs.

(4) The motorist shall provide to the DPS, prior to expiration of a parts availability time extension, adequate documentation that one of the following conditions exists:

(A) the motor vehicle passed a retest;

(B) the motorist qualifies for a Minimum Expenditure Waiver or Low Income Time Extension; or

(C) the motor vehicle shall no longer be operated in the program area.

(5) A vehicle which receives a parts availability time extension in one test cycle must have the vehicle repaired and retested prior to the expiration of such extension or the vehicle shall be ineligible for a parts availability time extension in the subsequent test cycle in addition to other penalties authorized for non-compliance.

(6) The length of a parts availability time extension shall depend upon expected delivery and installation dates of uncommon parts as determined by the DPS representative on a case-by-case basis and issued for either 30, 60, or 90 days or longer if necessary, but shall not exceed one test cycle.

(e) Individual vehicle waiver. If a vehicle has failed an I/M test, a motorist may petition the director of the DPS for an individual vehicle waiver. Upon demonstration that the motorist has taken reasonable measures to comply with the requirements of the vehicle emissions I/M program contained in the revised Texas I/M State Implementation Plan and that such waiver shall have minimal impact on air quality, the director may approve the petition, and the motorist may receive a waiver. Motorists may apply for the individual vehicle waiver each test cycle.

§114.53. Inspection and Maintenance Fees.

(a) The following fees must be paid for an emissions inspection of a vehicle at an inspection station. This fee shall include one free retest should the vehicle fail the emissions inspection, provided that the motorist has the retest performed at the same station where the vehicle originally failed and submits, prior to the retest, a properly completed Vehicle Repair Form showing that emissions-related repairs were performed and the retest is conducted within 15 days of the initial emissions test.

(1) Through April 30, 2002, any emissions inspection station required to conduct a two-speed idle (TSI) test in accordance with §114.50(a)(1) of this title (relating to Vehicle Emissions Inspection Requirements) shall collect a fee of $13 and shall remit $1.75 to the Department of Public Safety (DPS).

(2) In El Paso County beginning May 1, 2002, any emissions inspection station required to conduct an emissions test in accordance with §114.50(a)(5)(A) or (B) of this title (relating to Vehicle Emissions Inspection Requirements) shall collect a fee of $14.

(3) In the Dallas/Fort Worth (DFW) program area beginning May 1, 2002, any emissions inspection station required to conduct an emissions test in accordance with §114.50(a)(2)(A) or (B), and in the extended DFW (EDFW) program area beginning May 1, 2003, any emissions inspection station required to conduct an emissions test in accordance with §114.50(a)(3)(A) or (B) of this title shall collect a fee of $22.50.

(4) In the Houston/Galveston program area beginning May 1, 2002, any emissions inspection station in Harris County required to conduct an emissions test in accordance with §114.50(a)(4)(A) or (B); beginning May 1, 2003, any emissions inspection station in Brazoria, Fort Bend, Galveston, and Montgomery Counties required to conduct an emissions test in accordance with §114.50(a)(4)(C) or (D); and beginning May 1, 2004, any emissions inspection station in Chambers, Liberty, and Waller Counties required to conduct an emissions test in accordance with §114.50(a)(4)(E) or (F) shall collect a fee of $22.50.

(b) The per-vehicle fee and the amount the inspection station remits to the DPS for a challenge test, at an inspection station designated by the DPS, shall be the same as the amounts set forth in subsection (a) of this section. The challenge fee shall not be charged if the vehicle is retested within 15 days of the initial test.

(c) Inspection stations performing out-of-cycle vehicle emissions inspections for the state's remote sensing element shall charge a motorist for an out-of-cycle emissions inspection in the amount specified in subsection (a) of this section, resulting from written notification that subject vehicle failed on-road testing. If the vehicle passes the vehicle emissions inspection, the vehicle owner may request reimbursement from DPS.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009077

Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

SUBCHAPTER I. NON-ROAD ENGINES
DIVISION 3. NON-ROAD LARGE SPARK-IGNITION ENGINES

30 TAC §114.421, §114.429

The Texas Natural Resource Conservation Commission (commission) adopts amendments to §114.421, Emission Specifications, and §114.429, Affected Counties and Compliance Schedules. These amendments to Chapter 114, Control of Air Pollution from Motor Vehicles; Subchapter I, Non-road Engines; Division 3, Non-road Large Spark-ignition Engines; and corresponding revisions to the associated state implementation plan (SIP) are being adopted in order to extend the existing requirements for non-road, large spark-ignition (LSI) engines to all counties in the state thus controlling ground-level ozone in the state. These amendments are one element of the control strategy for the HGA Post-1999 Rate-of-Progress (ROP)/Attainment Demonstration SIP. The new §114.421 and §114.429 are adopted *without changes* to the proposed text as published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8203) and will not be republished.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULE

The Houston/Galveston (HGA) ozone nonattainment area is classified as Severe-17 under the Federal Clean Air Act (FCAA) Amendments of 1990 (42 United States Code (USC), §§7401 et seq.), and therefore is required to attain the one-hour ozone standard of 0.12 parts per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined by Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties, has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of its Post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base-case episodes, adopted rules to achieve a 9% ROP reduction in volatile organic compounds (VOC), and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary nitrogen oxides (NO_x) waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base-case episodes which marginally exhibited model performance in accordance with the United States Environmental Protection Agency (EPA) modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data-gathering exercise known as the COAST study. The state believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, the EPA policy regarding SIP elements and timelines went through changes. Two national programs in particular resulted in changing deadlines and requirements. The first of these programs was the Ozone Transport Assessment Group (OTAG). This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in this study, and it has been concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that has impacted the SIP planning process is the revisions to the national ambient air quality standard (NAAQS) for ozone. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, the EPA proposed an interim implementation plan (IIP) that it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development timelines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, that standard would continue to apply until it is attained. The FCAA requires that HGA attain the standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998 a revision to the HGA SIP which contained the following elements in response to the EPA guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by the Subpart 2 of Title I of the FCAA to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the state eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs as well as an acceleration simulation mode equivalent motor vehicle inspection and maintenance program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory statewide programs adopted or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon Scenario VIf); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review; and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-99 ROP plan by December 31, 2000; to perform a mid-course review by May 1, 2004; and to perform modeling of mobile source emissions using the EPA mobile source emissions model (MOBILE6), to revise the on-road mobile source budget as needed, and to submit the revised budget within 24 months of the model's release. In addition, if a conformity analysis is to be performed between 12 months and 24 months after the MOBILE6 release, the state will revise the motor vehicle emissions budget (MVEB) so that the conformity analysis and the SIP MVEB are calculated on the same basis.

In order for the state to have an approvable attainment demonstration, the EPA indicated that the state must adopt those strategies modeled in the November submittal and then adopt sufficient controls to close the remaining gap in NO_x emissions. The modeling and other analysis supporting these rules and the HGA SIP indicate a gap of approximately an additional 91 tons per day (tpd) of NO_x reductions is necessary for an approvable attainment demonstration. The commission estimates that this measure will achieve a minimum of 2.8 tpd of NO_x equivalent reductions and is therefore a necessary measure to consider for closing the gap and successfully demonstrating attainment.

The emission reduction requirements included as part of this SIP revision represent substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, have worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

This rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register,* or were included in the HGA SIP considered by the commission on December 6, 2000 and planned to be submitted to EPA by December 31, 2000.

The amount of NO_x reductions required for the area to attain the ozone NAAQS has 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 reduction strategies. The FCAA, 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 oversight committee. Commission staff have continued to improve the air quality modeling technology and refine emission inventory data. Numerous emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources, on-road and non-road mobile sources, and area sources were analyzed in multiple iterations of modeling, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling and other analysis submitted for public hearing and comment concurrently with the HGA SIP show that a significant amount of NO_x reductions practicably achievable are necessary from ozone control strategies in order for the HGA nonattainment area to achieve the ozone NAAQS by 2007, including reductions from surrounding counties included in the HGA consolidated metropolitan statistical area (CMSA).

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies. At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The current SIP revision contains rules, enforceable commitments, photochemical modeling analyses, and calculation of the remaining NO_x reductions required to reach attainment (gap calculation) in support of the HGA ozone attainment demonstration. In addition, this SIP contains Post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contains enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit a mid-course review.

The HGA ozone nonattainment area will need to ultimately reduce NO_x more than 750 tpd to reach attainment with the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of the non-road LSI engine rules will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area. The extension of these rules to all counties in the state should also contribute to maintenance of the one-hour ozone standard in the rest of the state.

The EPA has been regulating highway (on-road) cars and trucks since the early 1970s and continues to set increasingly stringent emissions standards for such vehicles. After considerable progress was made in controlling emissions from on-road vehicles, the EPA turned its attention to non-road (also called off-road) engines, which also contribute significantly to air pollution. Although emissions from non-road, LSI engines have not yet been regulated by the EPA, the California Air Resources Board (CARB) has adopted exhaust emission standards for these engines. Non-road, LSI engines are primarily used to power industrial equipment such as forklifts, generators, pumps, compressors, aerial lifts, sweepers, and large lawn tractors. The engines are similar to automotive engines and can use similar automotive technology, such as closed-loop engine control and three-way catalysts, to reduce emissions.

The CARB determined the exhaust emission standards for non-road, LSI engines to be technologically feasible and a cost-effective strategy at $.25 per pound ($500 per ton) of NO_x and hydrocarbons (HC) reduced, that will move the state toward reducing NO_x and HC from non-road, LSI engines. HC, also called VOC, and NO_x are precursor chemicals that contribute to the formation of ground-level ozone. The HGA area alone will contain 23% of the state's LSI engines, or approximately 88,374 engines, by 2007. Statewide, there will be approximately 371,096 LSI engines by 2007. Adoption and implementation of California standards for non-road, LSI engines throughout the state should reduce the amount of VOC and NO_x emissions from these sources and, therefore, help control ground-level ozone in nonattainment areas. For the HGA ozone nonattainment area, emission reductions by 2007 will be approximately 2.8 tpd. The program is estimated to cost about $500 per ton of NO_x reduced, which compares very favorably with the cost per ton of other emission control strategies.

These amendments are adopted in order to control ground-level ozone in the state by requiring model year 2004 and subsequent non-road, LSI engines 25 horsepower (hp) and larger to be certified under Title 13, California Code of Regulations, Chapter 9, concerning Off-Road Vehicles and Engines Pollution Control Devices (13 CCR 9), as adopted by the CARB on October 19, 1999 and effective November 18, 1999. The commission is incorporating the non-road, LSI engine rules by reference due to the need for the Texas program to remain identical to the program in California. For any state program that differs from the federal standards, 42 USC, §7543(e)(2)(B), requires the state programs to be identical. The rules will be effective throughout the State of Texas. These amendments are necessary in order to attain and maintain the ozone standard in nonattainment areas, and to establish a single equipment design standard for the state.

A single equipment design standard will help to prevent incompatibility and expense which may arise from the distribution of equipment with different emission standards.

The commission solicited comment on additional flexibilities relating to rule content and implementation which have not been addressed in this or other concurrent rulemakings. These flexibilities may be available for both mobile and stationary sources. Additional flexibilities may also be achieved through innovative and/or emerging technology which may become available in the future. Additional sources of funds for incentive programs may become available to substitute for some of the measures considered here. There were 46 comments received which are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

SECTION BY SECTION DISCUSSION

The intent of these amendments is to extend to all counties in the State of Texas the non-road, LSI standards that currently exist in the Dallas/Fort Worth (DFW) area. These existing standards are identical to the non-road, LSI standards in place in California.

The following sections of Division 3 were adopted during the DFW rule promulgation and were not reopened for public comment in this rulemaking action because no changes were proposed to these sections: §114.420, Definitions; §114.422, Control Requirements; and §114.427, Exemptions. The two sections of the rules being opened for comment were §114.421 and §114.429. Section 114.421 is amended to reflect the state-wide applicability of the LSI rules, and §114.429 is amended to reflect the compliance dates for the new portions of the state being affected by this rulemaking action.

Additionally, §§114.420, 114.422, and 114.427 were not reopened because they incorporate by reference the California non-road, LSI rules as those rules are set out in 13 CCR 9, concerning Off-Road Vehicles and Engines Pollution Control Devices, as adopted by the CARB on October 19, 1999 and effective November 18, 1999. The Texas program must remain identical to the California program, so the sections already incorporated by reference in the DFW rulemaking may not be changed to be different from the California 13 CCR 9 rules.

Existing §114.421 (Emission Specifications) incorporated by reference the 42 definitions found in 13 CCR 9, §2431 (Definitions). This rulemaking action made no changes to these definitions. Existing §114.429 applied the control requirements to nine counties in the DFW area which include Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties. These amendments extend the control requirements to all counties within the state. Section 114.429 also specifies the compliance schedule for engine manufacturers.

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed the rulemaking action in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and determined that the rulemaking action does not meet 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.

These adopted rules do not meet any of the four applicability criteria for requiring a regulatory analysis of "major environmental rule" as defined in the Texas Government Code. Section 2001.0225 applies only to a major environmental rule the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

The new sections to Chapter 114 are one element of the HGA attainment SIP. While the amended rules are intended to protect the environment, based on the analysis provided in the preamble, including the discussion in the PUBLIC BENEFIT AND COSTS section of the proposal preamble, the commission does not believe the rules will adversely affect, in a material way, the sale or use of non-road, LSI engines. The commission does not believe these entities comprise a sector of the economy, or that these rules will adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

These amendments to Chapter 114 are intended to protect the environment or reduce risks to human health from environmental exposure to ozone but are not anticipated to 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 would require units of state and local government, businesses, and individuals statewide that own or operate model year 2004 and subsequent non-road LSI engines of 25 hp and larger, and all equipment and vehicles that use such engines to use LSI engines certified under 13 CCR 9 as adopted by the CARB on October 19, 1999. The increased cost of $100 to $500 per engine would not cause material impact given the high total cost of this type of equipment.

These rules do not exceed an express standard set by federal law, since they implement requirements of the FCAA. Under 42 USC, §7410, states are required to adopt a SIP which provides for "implementation, maintenance, and enforcement" of the primary NAAQS in each air quality control region of the state. These rules were specifically developed as part of an overall control strategy to meet the ozone NAAQS set by the EPA under 42 USC, §7409. While 42 USC, §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 42 USC, Chapter 85, Air Pollution Prevention and Control). It is true that 42 USC 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 42 USC. The provisions of 42 USC 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 42 USC allows states to develop their own programs, this flexibility does not relieve a state from developing a program that meets the requirements of

§7410. In order to avoid federal sanctions, 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. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rule-making is intended to achieve emission reductions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. By policy, the EPA requires photochemical grid modeling to demonstrate whether the 42 USC, §7511a(f), NO_x measures would contribute to ozone attainment. The commission has performed photochemical grid modeling which predicts that NO_x emission reductions, such as those required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The 42 USC, §7511a(f), exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under 42 USC, §7511a(f), was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

During the 75th Legislative Session, Senate Bill (SB) 633 amended the Texas Government Code to require agencies to perform a regulatory impact analysis (RIA) of certain rules. The intent of SB 633 was to require agencies to conduct a RIA of extraordinary rules. 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 previously discussed, 42 USC 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 proposes and 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. Because 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 42 USC.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp,* 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue,* 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.,* 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert,* 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd,* Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor,* 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.,* 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore, in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, 382.017, 382.019, 382.039, and 382.051(d) authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct an RIA as provided in Texas Government Code, §2001.0225.

TAKINGS IMPACT ASSESSMENT

The commission evaluated this rulemaking action and performed an analysis of whether the proposed rules are subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. The specific purposes of these amendments are: to develop a new attainment demonstration SIP for the ozone NAAQS for HGA; and to establish emission requirements on model year 2004 and subsequent non-road, LSI engines 25 hp and larger and all equipment and vehicles that use such engines by requiring these engines to be certified under 13 CCR 9 throughout the state.

This rulemaking action will act as an air pollution control strategy to reduce NO_x emissions in the ozone nonattainment areas so that they may demonstrate attainment with the ozone NAAQS and maintain air quality in near nonattainment areas across the state. Promulgation and enforcement of these rules will not burden private, real property. Although these 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 partially fulfill a federal mandate under 42 USC, §7410. Specifically, the emissions limitations and delays within these rules were developed in order to meet the ozone NAAQS set by the EPA under 42 USC, §7409. States are primarily responsible for ensuring attainment and maintenance of the NAAQS once the EPA has established them. Under 42 USC, §7410 and related provisions, states must submit, for EPA approval, SIPs that provide for the attainment and maintenance of NAAQS through control programs directed to sources of the pollutants involved. Therefore, the purpose of these rules is to implement a cleaner-burning, non-road, LSI engine program necessary for the entire state to meet air quality standards established under federal law as NAAQS. Consequently, the exemption which applies to these rules is that of an action reasonably taken to fulfill an obligation mandated by federal law. Therefore, this rulemaking action will not constitute a taking under the Texas Government Code, Chapter 2007.

Also, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rule revisions 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 significantly advance the health and safety purpose. In addition, §2007.003(b)(4) provides that Chapter 2007 does not apply to these adopted rules since it is reasonably taken to fulfill an obligation mandated by federal law. The amendments will implement requirements of 42 USC, §7410. This action is taken in response to the HGA area exceeding the NAAQS for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient NO_x and ozone levels in HGA. Attainment of the ozone standard will eventually require substantial NO_x reductions. Any NO_x reductions resulting from the current rulemaking are no greater than what the best scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking action is only one step among many necessary for attaining the ozone standard.

The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis. Comments received during the comment period regarding the takings impact assessment (TIA) are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

COASTAL MANAGEMENT PROGRAM CONSISTENCY REVIEW

The commission determined that this rulemaking action relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et seq.), and the commission rules in 30 TAC Chapter 281, Subchapter B, Consistency with the Texas Coastal Management Program. As required by 31 TAC §505.11(b)(2) and 30 TAC §281.45(a)(3), relating to actions and rules subject to the CMP, commission rules governing air pollutant emissions must be consistent with the applicable goals and policies of the CMP. The commission reviewed this rulemaking action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and determined that this rulemaking action is consistent with the applicable CMP goals and policies. The primary CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations at 40 Code of Federal Regulations (CFR) to protect and enhance air quality in the coastal area. The rules, which require additional reductions of air emissions in HGA, will result in reductions of ambient NO_x and ozone concentrations. These rules are consistent with the applicable CMP policy because they are consistent with 40 CFR. Title 40 CFR, Part 51, sets out requirements for states to prepare, adopt, and submit implementation plans for the attainment of the NAAQS. The adopted rules would be submitted to the EPA under these requirements. No comments were received during the comment period regarding the CMP.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following times and locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000, in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; September 25, 2000, in Austin and Corpus Christi. The comment period closed on September 25, 2000.

The following 46 commenters provided written or oral testimony on this proposal: the City of Fort Worth (Fort Worth); the City of Lake Jackson (Lake Jackson); the League of Women Voters of Texas (LWV-TX); Hispanic Community for Texas Citizens for a Sound Economy (TCSE-HC); American Road and Transportation Builders Association (ARTBA); Baker Botts; Business Coalition for Clean Air (BCCA); Dow Chemical Company (Dow); Dynegy Inc. (Dynegy); the EPA; ExxonMobil Corporation (ExxonMobil); Hanover Compressor Company (Hanover); Harris County Judge Robert Eckels (Harris County); the City of Missouri City (Missouri City); Phillips 66 Company (Phillips 66); Reliant Energy, Inc. (REI); RMT, Inc. on behalf of Montgomery County (Montgomery Co.); Sierra Club Houston Regional Group (Sierra-Houston), and 28 individuals.

Fort Worth, Lake Jackson, LWV-TX; and ten individuals supported the proposed revisions, while the TCSE-HC; and four individuals opposed the proposed revisions. The ARTBA, Baker Botts, BCCA, Dow, Dynegy, the EPA, ExxonMobil, Hanover, Harris County, Missouri City, Phillips 66, REI, Montgomery Co., Sierra-Houston, and five individuals supported the proposed revisions, but suggested changes or clarifications as stated in the ANALYSIS OF TESTIMONY section of this preamble. ExxonMobil adopted the BCAA comments by reference, and Dow and one individual supported the BCCA comments.

ANALYSIS OF TESTIMONY

Sierra-Houston, LWV-TX, and one individual stated that all of these rules should be applied statewide. Sierra-Houston commented that these rules should be applied statewide so that maximum reductions in transboundary air pollution can be made and so that county boundaries cannot be used to avoid adherence to these rules. LWV-TX commented that SIP strategies that exceed those required by the EPA should be adopted.

The commission appreciates the commenters' support for statewide applicability of these rules. The commission notes, however, that it is not obligated to adopt all rules statewide in order to satisfy its commitments under the SIP, nor is the commission required to do so under 42 USC. Three of the proposed measures contain emission reduction strategies that have been proposed for state-wide applicability: California LSI engines; emissions banking and trading (that portion of the proposed rules which relates to the trading of emission reduction credits and discrete emission reduction credits); and low emission diesel fuel (that portion of the proposed rules which relates to on-road fuel).

In evaluating whether to implement all of the rules statewide, the commission took into account many concerns, including but not limited to, the need for the marketplace to be able to respond to regulation, the possible impacts on transport and distribution systems, the possibility of increased costs and financial burdens on regulated entities, and regional needs and issues associated with state-wide mandates. The commission also analyzed where emission reduction measures are most needed and where emission reduction measures will be most effective in order to demonstrate attainment.

Sierra-Houston resubmitted comment letters dated August 2, 1999, January 31, 2000, and February 24, 2000 concerning already-completed rulemakings and SIP revisions which Sierra-Houston had initially submitted during the comment period for these previous rulemakings and SIP revisions.

These comments were addressed in the ANALYSIS OF TESTIMONY section of the preambles to the earlier rulemakings and SIP revisions which were published in previous issues of the *Texas Register.*

One individual commented that the proposed rules are designed to embarrass the governor, and that the Texas Legislature and Congress should analyze these plans.

The commission's intent is not to embarrass Texas and the governor, but instead to comply with the timelines provided in the 1990 FCAA amendments and subsequent EPA guidance for submitting rules to demonstrate ozone attainment in HGA. Accordingly, Texas has committed to adopting the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000.

One individual stated opposition to tractor restrictions being applied to rural counties like Chambers and Liberty, because those counties add nothing to the pollution problem.

These rules apply to all counties throughout the state including Chambers and Liberty County. However, engines less than 175 hp used in agriculture and construction are exempt from these rules, so those living in rural counties who operate tractors with engines rated at less than 175 hp will not be affected by these rules.

One individual commented that recreational equipment should not be exempt from these rules, and another individual commented that no equipment should be exempted from these rules.

The commission appreciates the commenter interest in protecting air quality by suggesting inclusion of all equipment, including recreational equipment, in the scope of these rules. However, the commission disagrees with the suggestion that no equipment should be exempt from these rules, including recreational vehicles. The amendments to these rules incorporate by reference the California non-road, LSI engine rule because 42 USC requires that the Texas program be identical to the California non-road LSI program. Although emissions from non-road, LSI engines have not yet been regulated by the EPA, the CARB has adopted exhaust emission standards for these engines. These rules and amendments will apply throughout the State of Texas.

One individual commented that the phasing out of equipment should be a longer period so that small farmers or small business owners are not adversely affected.

These rules do not require an immediate phase-out of equipment. Rather, these rules require that any equipment which is replaced beginning in model year 2004 must be CARB-certified. Small farmers and small business owners should not experience financial harm from these rules because the CARB-certified engines are estimated to cost an additional $100 - $500 per piece of equipment. No significant fiscal implications are anticipated to individuals, state and local government agencies, and businesses statewide that own or operate affected equipment powered by LSI engines as a result of implementing these rules, unless a business or individual replaces between 200 and 1,000 of these engines annually.

One individual commented that fleet vehicles should not be required to meet the California emission standards.

These rules cover non-road LSI engines rated 25 hp or over, or equipment that uses engines of that size, whether or not the engines or equipment are to be used in a fleet. Non-road LSI engines over 25 hp are primarily used to power industrial equipment such as forklifts, generators, pumps, compressors, aerial lifts, sweepers, and large lawn tractors. Texas has chosen to adopt the California standards because they are more stringent than the current engine standards in place in Texas, and because implementation of the California standards is estimated to provide at least 2.8 tpd of NO_x-equivalent reductions which are needed in order for the HGA nonattainment area to achieve the ozone NAAQS by 2007. The extension of these rules to all counties in the state should also contribute to maintenance of the one-hour ozone standard in the rest of the state.

One individual commented that all equipment manufactured by Briggs and Stratton will meet the CARB emission standards. The individual stated that the engines already have a spark-advanced system, and that Briggs and Stratton will continue to follow California emission standards.

The commission is pleased to hear that companies such as Briggs and Stratton are complying with the California standards at this time and encourages Briggs and Stratton to continue to do so.

One individual commented that the registration of and pollution tax on engines over 24 hp is long overdue, and is necessary to determine the contribution of their emissions to the HGA ozone precursor problem.

The commission agrees with the commenter that these rules are necessary. However, these rules do not require the registration of, nor levy a tax on all engines 25 hp and greater. Rather, the rules require that non-road, LSI engines 25 hp or greater produced in model year 2004 and subsequent, be CARB-certified.

One individual commented that "these rules go far beyond anything necessary to protect the environment." The individual also commented that the basis and analysis for these rules is flawed. One individual added that the "guess" models are an insufficient basis upon which to base policy decisions and regulations, and that emission curtailment is necessary due to the long operational life of these engines.

The commission disagrees with the first three comments. The HGA is classified as a "severe" nonattainment area under 42 USC. If the commission were to propose a SIP with less stringent emission reductions, the HGA could face penalties from the federal government, including the loss of federal highway funds. In order to avoid such penalties, the commission has worked with all stakeholders to attempt to formulate strategies that can reduce emissions to levels that will satisfy the requirements of 42 USC. The current SIP revision contains photochemical modeling analysis in support of the HGA ozone attainment demonstration that meets all EPA criteria. Modeling staff used the latest technology to estimate emission levels across the state and has worked with EPA to study the air pollution dilemma in the HGA area. The commission estimates that this control measure will achieve a minimum of 2.8 tpd of NO_x-equivalent reductions and is therefore a necessary measure to successfully demonstrate attainment. The commission agrees that emission curtailment is necessary to help reduce NO_x.

One individual applauded the commission for passing rules related to more efficient engines, but asked that the commission not force people to do things they can't afford.

The commission appreciates the commenter's support for these rules related to engine efficiency. The commission is uncertain whether the commenter's monetary concern is for private individuals or businesses. These rules will not affect the average citizen, unless he or she uses LSI engines rated at or above 25 hp and the engines are not exempted under these rules. These engines are mainly used for industrial operations. There are no significant fiscal implications anticipated to individuals, state and local government agencies, and businesses statewide that own or operate affected equipment powered by LSI engines as a result of implementing these amendments unless a business or individual replaces between 200 and 1,000 of these engines annually. It is unlikely that the average citizen will replace a large quantity of these types of engines annually.

Fort Worth commented that it appreciates the efforts of the City of Houston and its regional partners in submitting a proposed SIP that is compliant with the 42 USC mandates because the DFW region is affected by the pollution generated in the HGA. Fort Worth also commented that it appreciates the commission efforts to enlarge the markets for affected LSI engines by applying these rules statewide.

The commission appreciates the commenter's support. The entire state will benefit from reduction of NO_x emissions and from the greater economy of scale. State-wide emission reductions help attainment areas maintain attainment status while assisting nonattainment areas in controlling and reducing NO_x emissions.

One individual commented that the California LSI engine rules should apply to all internal combustion engines in the HGA and the state. Dow commented that these rules do not make clear which equipment is included and asked the commission to clarify whether a diesel engine is of the LSI category.

Diesel engines are not affected by these rules. Diesel engines are classified as compression-ignition engines, not spark-ignition engines. Spark-ignition engines run on gasoline, not diesel fuel, therefore these rules do not apply to all internal combustion engines. The amendments to these rules incorporate by reference the California non-road, LSI engine rule, which does not apply to all internal combustion engines. These rules are identical to the rules effective in California because 42 USC requires that the Texas program be identical to the California non-road LSI program. Although emissions from non-road, LSI engines have not yet been regulated by the EPA, the CARB has adopted exhaust emission standards for these engines. These rules will apply throughout the State of Texas.

EPA commented that the statement relating to the incorporation by reference into the HGA SIP of future revisions to the California regulations should be removed as was done in the DFW SIP. Hanover commented that it understood these rules to state that all future amendments that may be passed in California will be adopted and incorporated into the Texas rules.

The EPA is correct. The preamble of these rules as published for proposal in the *Texas Register* contained two statements relating to the incorporation by reference into the Texas rules of all future revisions to the California regulations. Although the commission believes it has authority to adopt all future revisions by reference, the two statements relating to incorporation by reference of all future revisions have been removed from the preamble. The commission has deleted the statements relating to incorporation by reference to allow greater consideration of each change made by California prior to adoption of a change in Texas.

Lake Jackson commented that it can replace by 2007 its two pieces of equipment covered under these rules. Missouri City commented that it would experience increased costs associated with the purchase of new vehicles for the city fleet and the modification of existing equipment.

Lake Jackson may use the equipment it has on hand until the year 2007 and still remain in compliance with these rules. In fact, Lake Jackson and Missouri City can continue to use the equipment already on hand until that equipment fails and must be replaced whether that is in 2004, 2007, or beyond. If the equipment is replaced beginning in model year 2004 any new equipment using a non-road LSI engine must be CARB-certified. As noted elsewhere in this ANALYSIS OF TESTIMONY, these rules require model year 2004 and subsequent non-road, LSI engines 25 hp and larger to be certified under 13 CCR 9. Therefore, Missouri City will not be required to modify existing equipment. Furthermore, Missouri City should not experience significant increased costs associated with the purchase of new vehicles unless it replaces between 200 and 1,000 vehicles per year, because the estimated additional cost of the CARB-certified LSI engine is approximately $100 - $500 per vehicle. Finally, these rules do not apply to on-road vehicles.

One individual supported stricter automobile emission standards and would approve of a proposal making trucks and sport utility vehicles (SUV) meet California LSI standards.

The commission appreciates the commenter's enthusiasm for stricter emission standards. The commission notes, however, that these rules apply only to non-road engines. The commenter seems to be registering support for stricter standards for on-road trucks and SUVs. The EPA has adopted the Tier II standards which require most trucks and SUVs to meet emission standards similar to light-duty gasoline automobiles.

One individual commented that "non-road engine strategies" would bankrupt businesses and undermine family lives.

The commission does not believe that these rules will have the negative financial impact predicted by the commenter. No significant fiscal implications are anticipated to individuals, state and local government agencies, and businesses statewide, unless an entity replaces between 200 and 1,000 of these engines annually. The CARB has determined the exhaust emission standards for non-road, LSI engines to be technologically feasible and a cost-effective strategy at $.25 per pound ($500 per ton) of NO_x and HC reduced, that will move the state toward reducing NO_x and HC from non-road, LSI engines.

ARTBA commented on six proposed rules collectively calling them the "proposed construction rules." ARTBA included California LSI engine standards in this group. ARTBA stated that these rules will threaten public and occupational safety, and that these rules will create negative social and economic effects which the commission has not studied.

The commission first notes that although ARTBA included the California LSI engine rules in its general category of proposed construction rules, ARTBA acknowledged that the FCAA expressly preempts all of the proposed construction rules except the California LSI standards. This statement implies that ARTBA's comments are focused on the remaining five proposed rules it includes in the proposed construction rules, not on the California LSI engine proposed rule. ARTBA stated elsewhere in its comments that only California may adopt standards or requirements relating to non-road vehicles, and ARTBA observes that only the commission's LSI standards follow the prescribed FCAA §209(e) procedures for adopting nonroad emissions regulations. ARTBA noted that "if and only if California does so, other states may then mirror California's actions, but may not deviate from them." The LSI engine rules mirror California's rules, as explained elsewhere in this ANALYSIS OF TESTIMONY.

Assuming that ARTBA's comments were intended to express ARTBA's belief that the California LSI engine rules will "threaten public and occupational safety, and create negative social and economic effects which the commission has not studied, the commission does not agree that these rules will have the negative impacts predicted by ARTBA. These rules will, to the contrary, prevent a real and substantial threat to public health and safety via the reduction of air pollution, and partially fulfill a federal mandate under 42 USC, §7410. Specifically, the emissions limitations and delays within these rules were developed in order to meet the ozone NAAQS set by the EPA under 42 USC, §7409.

The commission disagrees that possible negative social and economic effects of these rules have not been studied. There are no significant fiscal implications anticipated to individuals, state and local government agencies, and businesses statewide that own or operate affected equipment powered by LSI engines as a result of implementing these rules and amendments unless an entity replaces between 200 and 1,000 of these engines annually. The CARB has determined the exhaust emission standards for non-road, LSI engines to be technologically feasible and a cost-effective strategy at $.25 per pound ($500 per ton) of NO_x and HC reduced, that will move the state toward reducing NO_x and HC from non-road, LSI engines.

ARTBA encouraged the commission to consider adopting incentive programs to reduce mobile source emissions from both on-road motor vehicles and non-road vehicles, and to adopt both incentive programs and command and control regulations on stationary sources.

The commission agrees that economic incentive programs can potentially be an effective tool for achieving air quality. One such program is the Carl Moyer program in California. That program appears to be successful in providing flexibility to the regulated industry while still achieving reductions in air emissions. The California program is authorized by and funded through the state legislative process and such legislative approval does not currently exist for a similar Texas program. The commission will continue to try to identify economic incentives which it has authority to implement. Because the commission agrees that market-based incentive programs can be an important component in encouraging development of new technologies and/or greater or more cost effective emission reduction strategies, the commission has provided for the inclusion of economic incentive programs as a component of the HGA SIP in the future.

Hanover requested clarification as to whether the type of engine it uses (minor source semi-portable compressor engines) is exempted from these rules, and whether an exemption can be added to these rules for clarity. Hanover believed that minor source semi-portable compressor engines should be exempted due to their short projected useful life. Hanover also noted that the control systems required by these rules would involve costs of development, implementation, and maintenance far beyond the estimates contained in the proposal.

The type of engine to which Hanover refers is the type of engine intended to be regulated by this proposed rule, therefore no exemption will be added to the rules. The commission disagrees that semi-portable compressor engines should be excluded from these rules based upon the length of their projected useful life because these are precisely the types of engines that the commission is seeking to include in these rules. The commission cannot exempt these engines because these rules must remain identical to the California rule. The following is quoted from an EPA Engine Programs and Compliance Division Memorandum dated January 29, 1999, titled *California Requirements for Large SI Engines and Possible EPA Approaches:* "Upgrading to modern engine technologies greatly improves the capability of these engines to control emissions and will generally improve engine performance. Electronically-controlled closed-loop operation also provides the potential for great improvement in engine operation. For example, improving control of combustion may allow a fuel economy improvement of 15% to 20%. Also, feedback control of air-fuel ratios eliminates much of the need to maintain and adjust a large number of fuel system calibrations, resulting in reduced product inventories and, more importantly, less downtime and maintenance for equipment in the field. Finally, improved control of the upgraded engines should lead to significantly longer engine lifetimes. The net present value of these benefits would likely be considerably greater than the incremental cost of improving the engines."

No significant fiscal implications are anticipated to negatively impact individuals, state and local government agencies, and businesses statewide that own or operate affected equipment powered by LSI engines as a result of implementing the proposed amendments unless an entity replaces between 200 and 1,000 of these engines annually.

Montgomery Co. commented that it should be excluded from these rules based on its assumption that exclusion of this area would result in a difference of less than 1/1000th (0.001) of a part per billion of ozone. One individual stated opposition to these rules being applied to counties like Chambers and Liberty, because those counties add "nothing" to the pollution problem.

The FCAA Amendments of 1990 provided new requirements for areas that had not attained the NAAQS for ozone, carbon monoxide, particulate matter, sulfur dioxide, nitrogen dioxide, and lead, and new requirements for SIPs in general. The EPA was authorized to designate areas failing to meet the NAAQS for ozone as nonattainment and to classify them according to severity. The FCAA, §107(d)(4)(A)(iv) mandated that areas designated as serious, severe, or extreme for ozone that were within a metropolitan statistical area (MSA) or CMSA must have boundaries that include the entire MSA or CMSA. This requirement is supported by the legislative history for the 1990 FCAA Amendments in Senate Report No. 101-228, page 3399, "because ozone is not a local phenomenon but is formed and transported over hundreds of miles and several days, localized control strategies will not be effective in reducing ozone levels. The bill, thus, expands the size of areas that are defined as ozone nonattainment areas to assure that controls are implemented in an area wide enough to address the problem." The 1990 FCAA Amendments did provide the ability to exclude portions of the entire MSA or CMSA prior to designation, if the state conducted a study, to which the EPA agreed, that proved the geographic portion did not contribute significantly to violation of the NAAQS.

Redesignation has not occurred for any portion of the HGA nonattainment area, and is not currently being considered. For existing areas currently included within a nonattainment area, the specific area must be redesignated as attainment in order to be removed from a nonattainment area. The FCAA, §107(d)(3) provides that the EPA may not redesignate a nonattainment area, or a portion of a nonattainment area, to attainment unless several criteria are met. These criteria include: a determination that the area has attained the NAAQS; there is a fully approved SIP for the area; there is a determination that the improvement in air quality is due to permanent and enforceable emissions reductions; there is an approved maintenance plan for the area; and the state has met all requirements for the area under FCAA, §110 and Part D.

However, even if a specific area within the HGA nonattainment area was redesignated by the EPA as attainment for ozone, reductions associated from all adopted ozone control strategies would still be necessary, because of the requirements of FCAA, §107(d)(3) and §175A which require maintenance plans for all redesignated areas. The maintenance plan must include the measures specified in §107(d)(3) and any additional measures that are necessary to ensure that the area continues to be in attainment with the NAAQS for ten years after the redesignation. Eight years after the redesignation, the state is required to submit an additional SIP revision to maintain the NAAQS for another ten years after the end of the first ten-year period.

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies.

At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on localized controls. However, for many years an ever 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, due to high levels of ozone and ozone precursor entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The commission has conducted air quality modeling and upper air monitoring that found regional air pollution should be considered when studying air quality in the Texas ozone nonattainment areas. This work is supported by research conducted by the OTAG, the most comprehensive attempt ever undertaken to understand and quantify the transport of ozone. Both the commission and the OTAG study point to the need to take a regional approach to controlling air pollutants.

REI commented that the emission limitations have been developed with a less than complete analysis of the technical or economic feasibility, inaccurate cost estimates, and a less than complete analysis of the possible environmental or economic disbenefit of the controls. One individual commented that the rules may harm economic growth.

The commission disagrees with the comments and made no change in response to these comments. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of the proposed rules. This information met the statutory requirements of the TCAA and the Texas Administrative Procedure Act (APA) because the information provided in the proposed rules was sufficient for commenters to submit alternative assessments of the costs and benefits.

Adequate notice is essential for fairness as well as a meaningful opportunity to comment on proposed rules. *United Loans, Inc. v. Pettijohn,* 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The commission received intelligent comments which were substantial in both number and in scope, regarding the costs of the proposed rules and the technical practicability of compliance. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree. To simply state that the proposal did not meet the statute or that compliance with the proposed rules is not technically or economically feasible does not provide the commission with sufficient information to propose changes or alternative strategies. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the notice must include the cost of a reasonable method of compliance. Mere disagreement with cost or technical feasibility estimates does not render notice inadequate.

The rule proposal met the requirement to include sufficient information, because it provided an explanation of the costs associated with implementation of the rule requirements, as well as the date upon which CARB-certified engines must be made available for purchase. To simply state that the proposal failed to provide sufficient information does not provide the commission with sufficient information to propose changes or alternative strategies. The commenters did not say how the notice is insufficient, merely that it is insufficient. Nevertheless, the commission reviewed the notice and determined it to have been adequate. The commission responses to comments regarding costs of compliance with these rules are discussed in the FINAL REGULATORY IMPACT ANALYSIS DETERMINATION section of this preamble and throughout this ANALYSIS OF TESTIMONY. The commission response to technical feasability of these rules is also discussed in the BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULE section of this preamble and throughout this ANALYSIS OF TESTIMONY.

One individual commented that the rule package does not contain any information concerning the effectiveness of this equipment, therefore the individual would like to see a pilot program initiated before these rules are adopted.

The commission will not be performing a pilot program due to the success of these rules in California. The commission is relying on data obtained by the CARB to justify the effectiveness of these rules, which the commission is entitled to do because of the need for the Texas program to remain identical to the California program. With respect to effectiveness of equipment, the following is quoted from an EPA Engine Programs and Compliance Division Memorandum dated January 29, 1999, titled *California Requirements for Large SI Engines and Possible EPA Approaches:* "Upgrading to modern engine technologies greatly improves the capability of these engines to control emissions and will generally improve engine performance. Electronically-controlled closed-loop operation also provides the potential for great improvement in engine operation. For example, improving control of combustion may allow a fuel economy improvement of 15% to 20%. Also, feedback control of air-fuel ratios eliminates much of the need to maintain and adjust a large number of fuel system calibrations, resulting in reduced product inventories and, more importantly, less downtime and maintenance for equipment in the field. Finally, improved control of the upgraded engines should lead to significantly longer engine lifetimes. The net present value of these benefits would likely be considerably greater than the incremental cost of improving the engines." There are no significant fiscal implications anticipated to individuals, state and local government agencies, and businesses statewide that own or operate affected equipment powered by LSI engines as a result of implementing these rules unless an entity replaces between 200 and 1,000 of these engines annually. The commission estimates that this measure will achieve a minimum of 2.8 tpd of NO_x equivalent reductions and is therefore a necessary measure for successfully demonstrating attainment.

These rules will go into effect without a pilot program due to the fact that these rules and the others contained in the SIP package that pertain to the HGA and the state are necessary for the HGA to meet attainment by 2007. Furthermore, the commission has studied the results that California has experienced with this program and is convinced of its effectiveness in reducing emissions in a cost-effective manner.

Several individuals inquired about who would enforce these rules, and commented that enforcement of the proposed rules will be difficult, impossible, and expensive. One individual asked how the commission will ensure that the engines affected by these rules will be inspected for compliance, because they do not have to be inspected like those engines that are licensed for highway use.

As with all of its rules, the commission will enforce the requirements after the rule compliance date and take appropriate action for noncompliance situations. The rules are enforced by staff in the commission's regional offices, as well as local air pollution control programs. Local governments have the same power and are subject to the same restrictions as the commission under TCAA, §382.015, Power to Enter Property, to inspect the air and to enter public or private property in its territorial jurisdiction to determine if the levels of air contaminants meet levels set by the commission. Local governments are not required to enforce commission rules, but may sign cooperative agreements with the commission to enforce the rules under TCAA, §382.115, Cooperative Agreements. Local programs can also enforce commission rules without signing a cooperative agreement. The authority of local governments to enforce air pollution requirements is specified in detail in TCAA, §§382.111 - 382.115, and local governments can institute civil actions in the same manner as the commission under Texas Water Code (TWC), §7.351.

The commission will work with local officials to ensure enforcement of the SIP and SIP rules. The commission has existing relationships with pollution control authorities in the City of Houston, Harris County, and Galveston County for enforcement of other commission rules. The commission will continue enforcement relationships with these entities and develop relationships with other local officials as needed to create effective enforcement mechanisms for the SIP and SIP rules.

BCCA, Dynegy, ExxonMobil, Phillips 66, and REI stated that the proposed rules did not include an adequate small business and micro-business assessment as required under Texas Government Code, §2006.002. The commenters stated that an analysis of the costs of compliance for small and micro-businesses must also compare the costs of compliance for these businesses with the costs for the largest businesses affected by these rules. The commenters stated that the comparison must use at least one of the following standards: cost for each employee, cost for each hour of labor, or cost for each $100 of sales. The commenters asserted that the rule proposal failed to include the mandated cost comparison standards. The commenters stated that this is the case even in those instances where the commission acknowledged a significant impact. The commenters stated that the commission either restated the costs of compliance it identified in the analysis of public benefits and costs, or concluded that it cannot determine the cost to small businesses. The commenters stated that the rule proposal preamble stated that "the estimated capital and annualized cost of installing and operating control technology used for the various types of equipment in the fiscal note would appear to be a reasonable cost estimate for small and micro-businesses." (25 TexReg 8293).

The commenters asserted that the rule proposal assessments fall short of what Texas law requires and that it is not sufficient for the commission merely to state that the costs for small and large businesses will be the same. The commenters stated that the rationale behind requiring a comparison using an established standard, e.g., cost for each employee, cost for each hour of labor, or cost for each $100 of sales, is to determine whether there is a disparate impact on small businesses. The commenters stated that according to *Unified Loans v. Pettijohn,* 955 S.W.2d at 652 (Court of Appeals -- Austin, 1997), the statute's purpose is to obtain "an objective assessment of the agency's proposed action by forcing it to consider seriously. . . the effect of these rules on small businesses, including an analysis of their costs of compliance and a comparison of their costs with the cost of compliance for the largest businesses affected . . . ." The commenters stated further that the commission cannot merely conclude that the costs to small businesses "cannot be determined," and is obliged to include in the notice "some basis" for its conclusion so that interested parties can "confront that basis in a meaningful way in their comments." (*Unified Loans v. Pettijohn,* 955 S.W.2d at 653.)

The commenters stated that in the rule proposal preamble, the commission did not publish the information mandated by Texas law and that as a result, it is impossible for the public to comment on whether the agency adequately considered the effect of these rules on small businesses, thus rendering the notice of the plan inadequate. The commenters stated that Texas Government Code, §2006.002, requires the commission to provide a comparison of the proposed rule impact on small and large businesses, using the specified standards, for public review and comment before adoption.

The commission estimated, to the extent possible, the costs to small businesses and determined that the cost depends more upon the number of non-road engines operated by the business, and that it is not dependent upon the number of employees, hours of labor, or amount of sales income. Some small businesses have only one piece of non-road equipment while others have large fleets. Large businesses vary in the same way. The size of the fleet is not dependent upon the size of the business. The commission provided the estimated cost per piece of equipment and argues that this is the only meaningful way to provide sufficient notice of the cost to small business and therefore that it meets the objective of Texas Government Code, Chapter 2006. This assertion is supported by the fact that no small businesses provided comments which include cost of compliance in terms of the number of employees, hours of labor, or amount of sales income.

ARTBA, BCCA, Dynegy, ExxonMobil, Phillips 66, and REI commented on the draft RIA and stated that the proposed rules were not evaluated in accordance with the analysis requirements for a major environmental rule. The commenters stated that Texas Government Code, §2001.0225, requires an RIA for certain major environmental rules. The commenters stated that the commission must consider the benefits and costs of the proposed rules in relationship to state agencies, local governments, the public, the regulated community, and the environment. The commenters stated further that the commission must also incorporate aspects of this analysis into the fiscal note in the proposed rules, e.g., identify the costs and the benefits; describe reasonable alternative methods for achieving the purpose of these rules considered by the agency; provide the reasons for rejecting those alternatives; and identify the data and methodology used in performing the analysis. The commenters stated that under §2001.0225(d) the commission must also find that "compared to the alternative proposals considered and rejected, these rules will result in the best combination of effectiveness in obtaining the desired results and of economic costs not materially greater than the costs of any alternative regulatory method considered."

The commenters stated that the rule proposal preamble statement, that the rules are exempt from the RIA requirement because federal law mandates the rules, is a legally flawed effort to avoid an RIA and may render these rules invalid. The commenters stated that federal law does not mandate the control requirements, emission rates, and use restrictions contained in the proposal and asserted that many of the proposed rules exceed specific federal rules and standards applicable to the same sources. The commenters stated that examples of departures from the federal framework include the following: boiler, turbine, and other fired-equipment emission limits set well below federal new source performance standards, reasonably available control technology, best available control technology, or lowest achievable emission rate limits for the same sources; and compressor engine emission limits set at unprecedented low levels specifically designed to be unachievable and prevent the further use of the affected engines.

The commenters stated that the rule proposal preamble acknowledges that the rules are "major environmental rules," but that the commission asserted that an RIA is "seldom" required and is only required for "extraordinary" rules. The commenters stated that these criteria appear nowhere in the RIA requirements. The commenters stated that the rule proposal preamble states that "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." The commenters stated that this "no greater than is necessary or appropriate" determination is the conclusion that an RIA is designed to evaluate and to offer for public review and comment. The commenters stated that the rule proposal is well beyond any federal mandates for the covered sources and are "extraordinary." The commenters stated that under Texas Government Code, §2001.0225, an RIA must be performed and offered for public comment before the proposal can be adopted.

The commission disagrees with ARTBA, BCCA, Dynegy, ExxonMobil, Phillips 66, and REI that the rules are legally flawed. While the rules may require those entities purchasing new CARB-certified LSI engines upon replacement of worn out engines, that alone is not enough to trigger the RIA requirements. The Texas Government Code, §2001.0225 only applies to a major environmental rule adopted by a state agency, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

This rulemaking action does not meet any of these four applicability requirements, and is adopted in substantial compliance with the RIA requirements of Texas Government Code, §2001.035. These rules do not exceed an express standard set by federal law because the LSI non-road engine requirements are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. Title 42 USC, §7410 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 42 USC, §7410 does not specifically prescribe programs, methods, or reductions to meet the federal 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 42 USC, Chapter 85, Air Pollution Prevention and Control). The FCAA does require some specific measures for SIP purposes, such as an inspection and maintenance program, but those programs are the exception, not the rule, in the federal SIP structure. The provisions of 42 USC 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. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Failure to develop control strategies to demonstrate attainment can result in federal sanctions. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by 42 USC. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with 42 USC. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analyses indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking action is intended to achieve reductions in ozone precursor emissions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by 42 USC.

This conclusion is supported by the legislative history for Texas Government Code, §2001.0225. During the 75th Legislative Session, SB 633 amended the Texas Government Code to require agencies to perform an RIA of certain rules. The intent of SB 633 was to require agencies to conduct a RIA of 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. 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. Because of the ongoing need to address nonattainment demonstrations required by federal law, the commission routinely proposes and adopts SIP rules. If each rule proposed for inclusion in the SIP was incorrectly considered as exceeding federal law, every SIP rule would require the full RIA contemplated by SB 633. This result would be inconsistent with the cost estimates and fiscal notes prepared by the commission and by the LLB. 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 meet the requirements under §2001.0225(a). While the SIP rules will have a broad impact, that impact is no greater than is necessary or appropriate to meet the requirements of 42 USC. In other words, the rules are intended to meet federal and state law, and does not go above and beyond what is required to meet federal or state statutes.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp,* 919 S.W.2d 485. 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue,* 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.,* 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert,* 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd,* Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor,* 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.,* 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the APA by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore, in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, 382.017, 382.019, and 382.039; authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

BCCA, Dynegy, ExxonMobil, Phillips 66, and REI stated that the proposed rules did not include an adequate TIA as required under Texas Government Code, §2007. The commenters stated that the TIA provision mandates that covered agencies "take a 'hard look' at the private real property implications of the actions they undertake...," according to the Office of the Attorney General, *Private Real Property Rights Preservation Act Guidelines* (21 TexReg 387, January 12, 1996). The commenters stated that under §2007.043, a TIA must describe the specific purpose of the proposed action, determine whether engaging in the proposed governmental action will constitute a taking, and describe reasonable alternative actions that could accomplish the specified purpose. The commenters stated that the agency must also explain whether these alternative actions also would constitute takings.

The commenters stated that agencies must also comply with guidelines developed by the Texas Attorney General when developing the TIA and that according to these guidelines, agencies must carefully review governmental actions that have a significant impact on the owner's economic interest. The commenters stated that these guidelines include the statement: "Although a reduction in property value alone may not be a 'taking,' a severe reduction in property value often indicates a reduction or elimination of reasonably profitable uses." (21 TexReg 392, January 12, 1996). The commenters stated that examples of aspects of the rule proposal that could significantly impact private real property in a manner that constitutes a taking include gas-fired compressor engines and other point source NO_x controls. The commenters stated that the rule proposal preamble acknowledged that retrofitting compressor engines to the level specified in the proposal (25 TexReg 8137 and 8291) is infeasible, and stated that the existing equipment, representing a significant capital improvement at a number of industrial sites, would be rendered unusable. The commenters stated that the 90% point source reduction requirement is economically and technologically infeasible for a number of existing sites, and that this requirement could cause a number of facilities to shut down their operations, dramatically impacting the value of their real property.

The commenters stated that the proposed rule preamble acknowledged that some of the rules may "burden" private real property, but claimed an exemption from performing a TIA based on the assertion that the proposal does not impose a greater burden than necessary to advance a health and safety purpose and that the proposal "reasonably" fulfills a federal mandate. (25 TexReg 8175, 8194, 8201, 8208, 8220, 8228, 8237, 8245, 8294, and 8295). The commenters stated that the commission provided the public no basis to infer that a cost/benefit analysis or a reasonableness determination was, in fact, performed as necessary to support the TIA exemption claim because the preamble contains only the bare assertions. The commenters asserted that the proposed rules will impose a greater burden than is necessary, and are not reasonably taken to fulfill a federal mandate. The commenters commented that according to the Attorney General's guidelines, a full TIA was required to be completed with the proposal, and that failure to perform a TIA could invalidate the rules.

The primary reason the commission determined that these rules did not constitute a takings under Texas Government Code, Chapter 2007 is that it will not burden private real property. These rules apply to non-road equipment which is not real property or appurtenance thereto.

In its analysis, the commission also found that this rulemaking action is exempt from Texas Government Code, Chapter 2007 under §2007.003(b)(4) because it is reasonably taken to fulfill an obligation mandated by federal law. The commission included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking action therefore meets the requirements of §2007.003(b)(4). For these reasons this rulemaking action not constitute a takings under Chapter 2007 and does not require additional analysis.

ExxonMobil, Phillips 66, and REI stated that the proposed rules did not include adequate notice as required under Texas Government Code, §2002.024. The commenters stated that §2001.024, requires adequate notice of a proposed rule, including information about its public benefits and costs. The commenters stated that adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule, and that courts have considered notice "adequate" only if: interested persons can confront the agency's factual suppositions and policy preconceptions; and the agency provides interested parties the opportunity to challenge the underlying factual data relied upon by the agency. The commenters asserted that in proposing the rules, the commission failed to provide interested parties with sufficient information to constitute adequate notice.

The commenters stated that the rule proposal preamble appears short of adequate notice because the cost estimates were "dramatically underestimated." The commenters stated that the commission published insufficient information and analysis regarding costs and impacts.

The commenters also noted that the rule proposal preamble stated that "there may be individual sources for which the equipment actual control costs are higher than the ones identified in this cost note," and asserted that through this statement the commission "acknowledged that its estimates may have been low."

The commenters stated that it has identified a number of critical gaps in the underlying factual data, methodology, and analysis in support of the proposed rules. The commenters asserted that the proposal included insufficient information and analysis regarding costs and impacts. The commenters asserted that the commission has not adequately responded to requests for additional information from stakeholders. The commenters stated that the following requests for information included outstanding: information regarding the modeling of emissions; information regarding the corrected emissions inventory database; and information supporting the estimated costs of control. The commenters stated that this information is necessary in order to comment effectively on the proposed rules and that data gaps in the proposal hindered effective comment.

The commission disagrees with the commenters and has made no change in response to these comments. Texas Government Code, §2001.024 requires that the notice of proposed rules must include certain information. Subsection (a)(5) requires the notice to state the public benefits expected as a result of the adoption of the proposed rules, and the probable economic cost to persons required to comply with these rules. Adequate notice is essential for fairness as well as a meaningful opportunity to comment on proposed rules. *United Loans, Inc. v. Pettijohn,* 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits. The commission received intelligent comments which were substantial in both number and in scope, regarding the costs as well as the benefits. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice. The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree.

To simply state that the proposal failed to provide sufficient information does not provide the commission with sufficient information to propose changes or alternative strategies. The commenters did not say how the notice was insufficient, merely that it was insufficient. Nevertheless, the commission reviewed the notice and determined that it is adequate. The commission response to comments regarding costs of compliance with these rules are discussed in the FINAL REGULATORY IMPACT ANALYSIS DETERMINATION section of this preamble and throughout this ANALYSIS OF TESTIMONY. The commission is unaware of any requests for additional information to which it was not completely responsive.

REI, BCCA, Dynegy, and ExxonMobil commented that the proposal did not have a local employment impact statement.

The commission agrees with the commenters that the rules may affect a local economy, however, does not agree that it is the responsibility of the commission to provide the local employment impact analysis. The APA requires state agencies to determine whether rules may affect a local economy before proposing the rules for adoption. If the agency determines that proposed rules may affect a local economy, the agency must send a copy of the proposed rules and other information to the Texas Workforce Commission (Workforce Commission) before the agency files notice of the proposed rules with the secretary of state. The APA requires the Workforce Commission to prepare a local employment impact statement for proposed rules, if a state agency requests the statement. The commission determined that the proposed rules might affect a local economy, and sent the proposed rule and other requested information to the Workforce Commission. The commission received a letter from the Workforce Commission, indicating that they did not have the ability to determine the potential local employment impacts for the proposed rules.

Baker Botts commented that it generally supports the ongoing efforts by the commission to develop a SIP that is technologically achievable, economically reasonable, and legally approvable. Baker Botts, BCCA, Dynegy, ExxonMobil, Harris County, Phillips 66, and an individual commented that the commission should incorporate into the SIP a greater level of reductions from federally preempted sources and stated that EPA-regulated sources account for about 40% of the NO_x emissions in the HGA. REI commented that federal NO_x reductions should be fully incorporated. The commenters stated that the EPA issued a number of regulations for some federally preempted sources, such as land-based spark engines; marine, recreational, and land-based diesel engines; aircraft and locomotive engines; well after the FCAA deadlines, and that the EPA recently strengthened rules for on-road and non-road vehicles and fuels, such as low sulfur gas and diesel, Tier II motor vehicles, heavy-duty highway vehicle standards, and non-road Tier 2/Tier 3 heavy-duty engine standards. The commenters stated that delays in implementing these rules have prompted the commission to propose technically and economically infeasible emission reductions from sources in HGA that the state has no authority to regulate to make up for the missing federal reductions. The commenters stated that these delays have forced the commission to propose expensive regional fuels and significant use restriction regulations. The commenters stated that the commission and the EPA can ensure an equitable distribution of the compliance burdens necessary to meet mandated air quality improvement in HGA only by allowing the SIP to capture anticipated emission reductions from federally preempted sources. Baker Botts noted that the EPA demonstrated a willingness to assume responsibility for a portion of emissions reductions by creating a process in Los Angeles called a "public consultative process," that would resolve issues related to emissions from national and international sources, and that the EPA has also provided flexibility in obtaining offsets by allowing states to provide offsets to refiners based on emissions reductions that the EPA projected would result from mobile sources using Tier II gasoline. Baker Botts suggested that this same sort of prospective crediting should be used to develop a more rational HGA SIP, and that the EPA should allow the commission to claim credit in the SIP for the prospective emission reductions that will result from implementation of the Tier II gasoline rule and from other federally preempted sources. Finally, Baker Botts cited two cases in which the District of Columbia Circuit Court approved the EPA flexibility with respect to statutory deadlines under 42 USC when the EPA failed to meets its own deadlines, and this failure was deemed to upset the balanced federal/state responsibilities under 42 USC. ExxonMobil commented that it supported the commission and the EPA crediting the HGA SIP with an additional 60 tpd of federally preempted emission reductions that will occur over the next ten years. Harris County commented that the commission should work with the EPA to accelerate the implementation schedule for federally preempted emissions so that at least one-half of the related emission reductions are achieved by 2007, and that as a part of this process, the commission should delineate federal assignments detailing the engine standards and emission reductions necessary to achieve real and sustainable pollution reductions.

The commission agrees with the commenters that emission reductions from federally preempted sources would provide benefits for the HGA SIP demonstration, and the inability of the commission to regulate certain source categories has necessitated the use of other ozone control strategies. However, the commission understands that the EPA SIP approval process does not provide a mechanism for credit for emission reductions that occur after the attainment date. The commission understands that EPA is not currently considering accelerating implementation schedules for existing federal rules. The commission is working with the EPA to determine the availability of SIP credit for many non-traditional control strategy mechanisms, like economic incentive programs and flexibility for preempted source categories. Additionally, the commission is working with the EPA to determine an appropriate federal contribution credit available for the HGA SIP.

STATUTORY AUTHORITY

The amendments are adopted under TWC, §5.103, which authorizes the commission to adopt rules necessary to carry out its powers and duties under the TWC, and under the Texas Health and Safety Code, TCAA, §382.017, which provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendments are also adopted under TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.019, which authorizes the commission to adopt rules to control and reduce emissions from engines used to propel land vehicles; and §382.039, which authorizes the commission to develop and implement transportation programs and other measures necessary to demonstrate attainment and protect the public from exposure to hazardous air contaminants from motor vehicles.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009082

Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

DIVISION 6. LAWN SERVICE EQUIPMENT OPERATING RESTRICTIONS

30 TAC §114.452, §114.459

The Texas Natural Resource Conservation Commission (commission) adopts new §114.452, Control Requirements; and §114.459, Affected Counties and Compliance Dates. The commission adopts these revisions to add new Division 6, Lawn Service Equipment Operating Restrictions, to Subchapter I, Non-road Engines; Chapter 114, Control of Air Pollution from Motor Vehicles; and to the associated state implementation plan (SIP). The commission adopts these amendments to Chapter 114 and corresponding revisions to the SIP in order to control ground-level ozone in the Houston/Galveston (HGA) ozone nonattainment area. The revisions are one element of the control strategy for the HGA Post-1996 Rate-of-Progress (ROP)/Attainment Demonstration SIP. Sections 114.452 and 114.459 are adopted *with changes* to the proposed text as published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8216).

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

The HGA ozone nonattainment area is classified as Severe-17 under the Federal Clean Air Act (FCAA) Amendments of 1990 (42 United States Code (USC), §§7401 et seq.), and therefore is required to attain the one-hour ozone standard of 0.12 parts per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined by Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties, has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of its Post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base-case episodes, adopted rules to achieve a 9% ROP reduction in volatile organic compounds (VOC), and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary nitrogen oxides (NO_x) waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base-case episodes which marginally exhibited model performance in accordance with the United States Environmental Protection Agency (EPA) modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data-gathering exercise known as the COAST study. The state believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, the EPA policy regarding SIP elements and timelines went through changes. Two national programs in particular resulted in changing deadlines and requirements. The first of these programs was the Ozone Transport Assessment Group (OTAG). This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in this study, and it has been concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that has impacted the SIP planning process is the revisions to the national ambient air quality standard (NAAQS) for ozone. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, the EPA proposed an interim implementation plan (IIP) that it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development timelines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, that standard would continue to apply until it is attained. The FCAA requires that HGA attain the standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998 a revision to the HGA SIP which contained the following elements in response to the EPA guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by the Subpart 2 of Title I of the FCAA to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the state eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs as well as an acceleration simulation mode equivalent motor vehicle inspection and maintenance program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory state-wide programs adopted or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon Scenario VIf); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review; and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-99 ROP plan by December 31, 2000; to perform a mid- course review by May 1, 2004; and to perform modeling of mobile source emissions using the EPA mobile source emissions model (MOBILE6), to revise the on-road mobile source budget as needed, and to submit the revised budget within 24 months of the model's release. In addition, if a conformity analysis is to be performed between 12 months and 24 months after the MOBILE6 release, the state will revise the motor vehicle emissions budget (MVEB) so that the conformity analysis and the SIP MVEB are calculated on the same basis.

In order for the state to have an approvable attainment demonstration, the EPA indicated that the state must adopt those strategies modeled in the November 1999 submittal and then adopt sufficient controls to close the remaining gap in NO_x emissions. The modeling and other analysis supporting these rules and the HGA SIP indicates a gap of approximately 91 tons per day (tpd) of NO_x reductions is necessary for an approvable attainment demonstration. The commission estimates that this measure will achieve a minimum of 0.23 tpd delay of NO_x until after noon. There will also be a 12.4 tpd delay in VOC emissions until after noon. Because the emission of NO_x and VOC, both precursors to the formation of ozone, will be delayed until after noon, this delay will lead to a reduction in ozone that is equal to approximately 4.6 tpd NO_x reduced. These reductions are a necessary measure to consider for closing the gap and successfully demonstrating attainment.

The emission reduction requirements included as part of this SIP revision represent substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

This rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000 and planned to be submitted to EPA by December 31, 2000.

The amount of NO_x reductions required for the area to attain the ozone NAAQS has been estimated by extensive use of air quality grid modeling, which because of its scientific and statutory grounding, is the chief policy tool for designing emission reduction strategies. The FCAA, 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 oversight committee. Commission staff have continued to improve the air quality modeling technology and refine emission inventory data. Numerous emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources, on-road and non-road mobile sources, and area sources were analyzed in multiple iterations of modeling, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling and other analysis submitted for public hearing and comment concurrently with the HGA SIP show that a significant amount of NO_x reductions practicably achievable are necessary from ozone control strategies in order for the HGA nonattainment area to achieve the ozone NAAQS by 2007, including reductions from surrounding counties included in the HGA consolidated metropolitan statistical area (CMSA).

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies. At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The current SIP revision contains rules, enforceable commitments, photochemical modeling analyses, and calculation of the remaining NO_x reductions required to reach attainment (gap calculation) in support of the HGA ozone attainment demonstration. In addition, this SIP contains Post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contains enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit a mid- course review.

The HGA ozone nonattainment area will need to ultimately reduce NO_x more than 750 tpd to reach attainment with the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of the lawn and garden service equipment operating restriction program will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area.

The purpose of these rules is to establish a restriction on the use of handheld and non-handheld spark-ignition engines that operate at or below 25 horsepower (hp), or 19 kilowatts. This air pollution control strategy would delay the emissions of NO_x from these engines until later in the day, thus limiting ozone production. This control strategy is necessary for the HGA nonattainment area to be able to demonstrate attainment with the NAAQS for ozone.

These rules would implement an operating-use restriction program requiring that the handheld and non-handheld spark-ignition engines, rated at 25 hp and below, be restricted from use by commercial operators between the hours of 6:00 a.m. and noon, April 1 through October 31. The affected handheld equipment includes, but is not limited to, trimmers, edgers, chain saws, leaf blowers/vacuums, and shredders. Non-handheld lawn and garden equipment includes such devices as walk-behind lawnmowers, lawn tractors, tillers, and small generators. The affected area would include the following counties within the HGA nonattainment area: Brazoria, Fort Bend, Galveston, Harris, and Montgomery. Based on estimated population, estimated population growth, and emissions estimates developed using EPA-approved methodologies, the commission believes it is not necessary to include Chambers, Liberty, and Waller Counties in the adopted rules. This issue is discussed in greater detail in the ANALYSIS OF TESTIMONY section of this preamble. The effective date would be April 1, 2005.

The intent of these rules is to limit the use of handheld and non-handheld spark-ignition lawn and garden service equipment that operate at or below 25 hp between the hours of 6:00 a.m. and noon. Other lawn and garden service work not requiring the use of handheld and non-handheld spark-ignition lawn and garden service equipment remains unrestricted under these rules. That is, electric or man- powered lawn equipment may be used. It should be noted however that the regulated types of lawn and garden service equipment are banned from use by commercial operators during the hours specified regardless of how they are being used.

The amount of NO_x shifted will total 0.23 tpd. The non-road mobile source category is one of the few sources of ozone-causing emissions that are not currently regulated under rules adopted by the commission. Federal controls on handheld lawn and garden service equipment such as cleaner-burning engines have been adopted and been in effect since 1997. More stringent standards will be phased in beginning with the 2002 model year.

The California Air Resources Board (CARB) stated that "using a commercial chain saw - powered by a two-stroke engine - for two hours produces the same amount of smog-forming hydrocarbon emissions as driving ten 1996 cars about 250 miles each." By shifting the hours of use for handheld and non-handheld spark-ignition lawn and garden service equipment until after noon, NO_x emissions from such lawn and garden equipment will not mix in the atmosphere with other ozone-causing compounds until later in the day. Ozone is formed through chemical reactions between natural and man-made emissions of VOC and NO_x in the presence of sunlight. Higher ozone levels occur most frequently on hot summer afternoons. The critical time for the mixing of NO_x and VOC is early in the day. By delaying the release of NO_x emissions from lawn and garden service equipment until later in the day, production of ozone will be stalled until optimum conditions no longer exist, thus avoiding the production of higher levels of ozone.

The commission solicited comment on additional flexibilities relating to rule content and implementation which have not been addressed in this or other concurrent rulemakings. These flexibilities may be available for both mobile and stationary sources. Additional flexibilities may also be achieved through innovative and/or emerging technology which may become available in the future. Additional sources of funds for incentive programs may become available to substitute for some of the measures considered here.

The commission also solicited comments on alternative applications of this rule including: innovative uses of technology, such as incentives to use ultra-low emission engines; alternative use restrictions, such as restricting use to every tenth day; and alternative restrictions on commercial use versus residential use, such as limiting the application of the rule to commercial services (which could be at residential property) or activities at commercial (versus residential) properties.

SECTION BY SECTION DISCUSSION

The new Division 6 is adopted regarding operating restrictions for commercial operators using lawn and garden service equipment powered by spark-ignition engines 25 hp or below.

The new §114.452(a) establishes operating restrictions for commercial operators' using lawn and garden service equipment. These rules restrict the operation by commercial operators of all handheld or non-handheld spark-ignition equipment 25 hp and below, between the hours of 6:00 a.m. and noon, during the time period between April 1 and October 31, except as specified in §114.452(b) and (c).

The new §114.452(b)(1) and (2) state that the use of spark-ignition engines under 25 hp are exempt from the requirements of these rules when used at a domestic residence by the owner of, or a resident at, that domestic residence, or when used by a non-commercial operator. New §114.452(b)(3) exempts any equipment used exclusively for emergency operations to protect human health and safety or the environment, including equipment being used in the repair of facilities, devices, systems, or infrastructure that have failed, or are in danger of failing, in order to prevent immediate harm to public health, safety, or the environment.

The new §114.452(c) states that commercial operators or persons who submit an approved emissions reduction plan are exempt from operating hour restrictions in 2005. The commission is requiring submission of the plans by May 31, 2003, to allow sufficient time to review and quantify the collective emission reductions the plans propose. The plans will be approved by the executive director and the EPA by May 31, 2004. The commission is requiring submission of the emissions reduction plans two years prior to the compliance date to allow adequate time for review of the plans, both by the commission and the EPA, and to allow the commission to ensure that the collective emission reductions achieved by the plans are equivalent to the ozone reductions achieved by implementation of the rules. Approved plans would allow commercial operators to operate during the restricted hours. In order to be approved, a plan must demonstrate NO_x and VOC reductions equivalent to those required by the rules, and the plan must contain adequate enforcement provisions. The commission will develop guidance in order to assist commercial operators in the development of their specific emission reduction plans. The commission intends for this guidance to contain an EPA-approved list of actions and operational changes that commercial operators can implement in order to achieve equivalent emission reductions of NO_x and VOC. Commercial operators would be able to submit a plan that uses these pre-approved actions or changes instead of developing a plan that would require case-specific approval by the executive director and the EPA. Reliance on the pre- approved measures will simplify the plan submittal process for commercial operators and will assist the executive director in the review and approval of each submittal. Commercial operators retain the option of developing their own plan which will be subject to executive director and EPA approval. The executive director may allow plans to be submitted after May 31, 2003. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division.

The new §114.452(d) states that a commercial operator is defined as any person who receives payment or compensation in exchange for operating lawn and garden service equipment powered by spark-ignition engines of 25 hp where the payment or compensation is required to be reported as income by the United States Internal Revenue Code. Generally speaking, this is any person who earns more than $400 a year using the aforementioned equipment. Furthermore, this term also includes any employees or contractors of any person as defined in the Texas Clean Air Act (TCAA), §382.003(10). This means that those entities like government bodies and/or businesses that sustain their own workforce to provide lawn and garden services are not exempt from these rules.

The new §114.459 specifies when the rule becomes effective (i.e., 2005), and the counties which are subject to the new requirements. The affected counties include Brazoria, Fort Bend, Galveston, Harris, and Montgomery Counties. Based on estimated population, estimated population growth, and estimated emissions developed using EPA-approved methodologies, the commission believes it is not necessary to include Chambers, Liberty, and Waller Counties in the adopted rule. This issue is discussed in greater detail in the ANALYSIS OF TESTIMONY section of this preamble.

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed this rulemaking action in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and determined that the rulemaking does not meet 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.

These adopted rules do not meet any of the four applicability criteria for requiring a regulatory analysis of "major environmental rule" as defined in the Texas Government Code. Section 2001.0225 applies only to a major environmental rule the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

As discussed earlier in this preamble, this rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000, and planned to be submitted to EPA by December 31, 2000.

These rules in Chapter 114 are intended to protect the environment or reduce risks to human health from environmental exposure to ozone and, although no estimates of cost were available to the commission at the time of proposal of the rules, the commission does not believe work delays could affect a sector of the economy in an adverse, material way. These rules are intended to implement an operating-use restriction program requiring that lawn and garden service equipment powered by spark- ignition engines, 25 hp or below utilized by commercial operators, or for uses not exempt under §114.452(b), will be restricted from use between the hours of 6:00 a.m. and noon, April 1 through October 31. This program is part of the strategy to reduce the formation of ozone by delaying NO_x emissions from lawn and garden equipment until later in the day when optimum conditions for the formation of ozone no longer exist. The program was developed for the HGA ozone nonattainment area to be able to demonstrate attainment with the ozone NAAQS. The commission does not believe that the businesses that provide lawn and garden services comprise a sector of the economy, nor does the commission believe that the rules will adversely affect in a material way, the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

These rules do not exceed an express standard set by federal law, since they implement requirements of the FCAA. Under 42 USC, §7410, states are required to adopt a SIP which provides for "implementation, maintenance, and enforcement" of the primary NAAQS in each air quality control region of the state. These rules were specifically developed as part of an overall control strategy to meet the ozone NAAQS set by the EPA under 42 USC, §7409. While 42 USC, §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 FCAA, Chapter 85, Air Pollution Prevention and Control). It is true that the FCAA does require some specific measures for SIP purposes, such as 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 42 USC, §7410. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to achieve reductions in ozone precursor emissions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. By policy, the EPA requires photochemical grid modeling to demonstrate whether the 42 USC, §7511a(f), NO_x measures would contribute to ozone attainment. The commission has performed photochemical grid modeling which predicts that NO_x emission reductions, such as those required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The 42 USC, §7511a(f), exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under 42 USC, §7511a(f), was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

During the 75th Legislative Session, Senate Bill (SB) 633 amended the Texas Government Code to require agencies to perform a regulatory impact analysis (RIA) of certain rules. The intent of SB 633 was to require agencies to conduct an RIA of extraordinary rules. 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 earlier in this preamble, 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 proposes and 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.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd, Inc.*, 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore, in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, 382.017, 382.019, and 382.039 authorize the commission to implement a plan for the control of the state's air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

Comments received during the comment period regarding the draft RIA are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

TAKINGS IMPACT ASSESSMENT

The commission evaluated this rulemaking action and performed an analysis of whether the rules are subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. The specific purpose of these amendments is to develop a new attainment demonstration SIP for the ozone NAAQS for HGA by adopting a lawn and garden service equipment operating-use limitation on engines 25 hp and below to delay NO_x emissions that lead to high levels of ground- level ozone production. This rulemaking action will act as an air pollution control strategy to shift NO_x emissions necessary for the HGA ozone nonattainment area to be able to demonstrate attainment with the ozone NAAQS. Adoption and enforcement of the rules will not burden private, real property as the rules only regulate handheld and non-handheld spark-ignition lawn and garden equipment rated at 25 hp or less.

Texas Government Code, §2007.003(b)(4), provides that Chapter 2007 does not apply to these adopted rules since they are reasonably taken to fulfill an obligation mandated by federal law. The requirements within this rulemaking were developed in order to meet the NAAQS for ozone set by the EPA under 42 USC, §7409. States are primarily responsible for ensuring attainment and maintenance of NAAQS once the EPA has established them. Under 42 USC, §7410, 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 implement a lawn and garden service equipment operating use limitation that is necessary for the HGA nonattainment area to meet the air quality standards established under federal law as NAAQS. Consequently, these rules meet the exception under §2007.003(b)(4).

In addition, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rule revisions 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 significantly advance the health and safety purpose. This action is taken in response to the HGA area exceeding the NAAQS for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient VOC and ozone levels in HGA. Consequently, these rules meet the exemption in §2007.003(b)(13).

The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explain in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis. Comments received during the comment period regarding the takings impact assessment (TIA) are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission determined that this rulemaking action relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et seq.), and the commission rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with the CMP. As required by §281.45(a)(3) and 31 TAC §505.11(b)(2), 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 reviewed this action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and determined that the action is consistent with the applicable CMP goals and policies. The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(1)). No new sources of air contaminants will be authorized and NO_x air emissions will be reduced as a result of these rules. The CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations in 40 Code of Federal Regulations (CFR), to protect and enhance air quality in the coastal area (31 TAC §501.14(q)). This rulemaking action complies with 40 CFR 50, National Primary and Secondary Ambient Air Quality Standards, and 40 CFR 51, Requirements for Preparation, Adoption, and Submittal Of Implementation Plans. Therefore, in compliance with 31 TAC §505.22(e), this rulemaking action is consistent with CMP goals and policies.

The commission solicited comments on the consistency of the proposed rules with the CMP during the public comment period. No comments were received during the comment period regarding the CMP.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000.

The number of commenters who provided oral testimony and/or submitted written testimony is 341. The following persons generally supported the proposal: British Petroleum-Amoco (BP) and 13 individuals. The following persons generally opposed the proposal: Liberty County EMS, Montgomery County Soil and Water Conservation, State Representative John Culberson, and 30 individuals. The following persons suggested changes to the proposal as stated in the ANALYSIS OF TESTIMONY section of this preamble: AAA Asphalt Paving Inc. (AAA), Air Cooled Engine Co. (ACEC), Amarillo Outdoor Power Equipment (AOPE), Baker Botts LLP (Baker Botts), Bell Janitorial (Bell), Bio Energy Landscape & Maintenance (Bio Energy), Business Coalition for Clean Air (BCCA), Citizens for a Better Environment (CBE), City of Beasley (Beasley), City of Galveston Public Works, City of Houston Mayor Brown, City of La Porte (La Porte), City of Missouri City (Missouri City), City of Simonton (Simonton), City of Spring Valley (Spring Valley), Clean Air

Partnership (CAP), Cornelius Nurseries, Inc. (Cornelius), Dayton Area Chamber of Commerce/Dayton Pipe Company (DACC/Dayton Pipe), Engine Education and Training Council (EETC), Engine Warehouse Inc. (EWI), Environmental Defense (ED), Excalibur Construction, Inc. (Excalibur), ExxonMobil Corporation (ExxonMobil), Frazier Lawn Service, Inc. (Frazier), Friendly Robotics, Galveston- Houston Association for Smog Prevention (GHASP), Grandparents of East Harris County (GEHC), Greenscape, HARC Center for Global Studies (HARC CGS), Harris County Judge Robert Eckels, Harris Landscape, The Hispanic Community of Texas Citizens for a Solid Economy (TCSE-HC), Houston-Galveston Metropolitan Planning Organization's Transportation Policy Council (Houston MPO), Johnson Saw & Lawnmower Sales & Service (Johnson), League of Women Voters of Texas (LWV-TX), Lynn's Landscaping, Inc. (Lynn's), Mayor Louise Richman - City of Spring Valley, Houston Metropolitan Transit Authority (Metro), Montgomery County (Montgomery Co.), Mothers for Clean Air (MCA), Mustang Mowing and Landscape Service (Mustang Mowing), National Aeronautics and Space Administration (NASA), Onalaska Equipment Rental and Repair, L.L.C. (Onalaska), Outdoor Power Equipment Institute (OPEI), Pampered Lawns, Pate and Pate Enterprises, Inc. (Pate & Pate), Personal Expressions Landscaping, Inc. (Personal Expressions), Phillips 66 Company (Phillips 66), Portable Power Equipment Manufacturers Association (PPEMA), Poulan Weedeater (Poulan), Public Citizen, Regional Air Quality Consensus Group (RAQCG), Ray's Nursery (Ray's), Reliant Energy, Inc. (REI), Rental Distributing Co. (RDC), Service Dealers Association (TSDA), Sierra Club Galveston Region (Sierra-Galveston), Sierra Club Houston Regional Group (Sierra-Houston), Small Business United of Texas (SBU Texas), Society of St. Vincent de Paul (SVP), State Representative Robert Talton, TNRCC Public Interest Counsel (PIC), Texas Association of Builders (TAB), Texas Citizens for a Sound Economy (CSE), Texas Department of Transportation (TxDOT), Texas Lawn and Landscape, Texas Nursery & Landscape Association (TNLA), Tropical Landscape Services, Inc. (TLS), EPA, Wakefield Landscape Service (Wakefield), Wesley Community Center, and 224 individuals. ExxonMobil, Phillips 66 and REI supported the comments submitted by the BCCA; therefore, references to BCCA will include references to these commenters. Lynn's, TLS, and Cornelius Nurseries supported the comments of TNLA, therefore, references to TNLA will include references to these commenters.

ANALYSIS OF TESTIMONY

BP and thirteen individuals commented that they supported the rules as proposed. Liberty County EMS, Montgomery County Soil and Water Conservation, State Representative John Culberson, and 30 individuals commented that they opposed the rule as proposed.

Two individuals expressed support for limiting the lawn mowing ban to commercial users only. Public Citizen and one individual commented that the rule should apply to both commercial entities and individuals. TNLA, Harris Landscape, Lynn's, AAA, Bell, Mustang Mowing, and two individuals commented that this rule should not be applied to commercial lawn and garden companies. One individual commented that individuals should be exempted from this rule.

The rule has been revised in response to these comments. The adopted rule exempts any use at a domestic residence by the owner of, or a resident at, that domestic residence or any use by a non- commercial operator. The rule also exempts any use that is exclusively for emergency operations to protect human health and safety or the environment, including equipment being used in the repair of facilities, devices, systems, or infrastructure that have failed, or are in danger of failing, in order to prevent immediate harm to public health, safety, or the environment. The commission made this change in the adopted rule to reduce the effect of the rule on individual home or property owners while maintaining a level of ozone reduction that allows the HGA area to demonstrate attainment of the ozone standard. The emission inventory maintained by the commission indicates that commercial operators are the source of the majority of weekday emissions from this type of equipment. The rule has a new definition of commercial operator. A commercial operator is defined as any person who receives payment or compensation in exchange for operating lawn and garden service equipment powered by spark-ignition engines of 25 hp or below where the payment or compensation is required to be reported as income by the United States Internal Revenue Code. This term also includes any employees or contractors of any person as defined in the TCAA, §382.003(10). This term is intended to cover lawn and garden service companies. The term also references the definition of "person" from the TCAA in order to include, for example, any employees or contractors of governmental entities, or corporations, that might employ or hire their own lawn and garden service staff.

The adopted rule does allow commercial operators who submit an emissions reduction plan by May 31, 2003, (which is approved by the executive director and the EPA no later than May 31, 2004) to be exempt from operating hour restrictions upon implementation of these rules in 2005. Thus, they would be permitted to operate during the restricted hours. The executive director may allow plans to be submitted after May 31, 2003. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division. In order to be approved, the plan must demonstrate NO_x and VOC reductions equivalent to those required by the rules being requested for exemption, and must contain adequate enforcement provisions.

Two individuals stated that any proposal which relies solely on the use of new technology to lower pollution will not work. One individual commented that the commission should not implement rules that are not based on proven technologies.

This rule does not call for the use of new or unproven technology. The purpose of the rule is to prohibit the use of lawn and garden equipment powered by small, spark-ignition engines 25 hp and below from 6:00 a.m. to 12:00 p.m. from April 1 to October 31 of each year except for domestic use and emergency operations. The concept of shifting emissions until the afternoon has been demonstrated to provide benefits in reducing ozone formation.

Dayton Pipe commented that Liberty County should be excluded from the HGA SIP stating that Liberty County does not contribute to Houston's ozone problem. An individual opposed implementation of the rules in Chambers and Liberty Counties. Montgomery County asked to be excluded from the proposed air pollution measures on the basis that doing so would not make any measurable difference in the Houston ozone problem.

The FCAA Amendments of 1990 provided new requirements for areas that had not attained the NAAQS for ozone, carbon monoxide, particulate matter, sulfur dioxide, nitrogen dioxide, and lead, and new requirements for SIPs in general. The EPA was authorized to designate areas failing to meet the NAAQS for ozone as nonattainment and to classify them according to severity. Section 107(d)(4)(A)(iv) of the FCAA mandated that areas designated as serious, severe, or extreme for ozone that were within a metropolitan statistical area (MSA) or CMSA must have boundaries that include the entire MSA or CMSA. This requirement is supported by the legislative history for the FCAA Amendments in Senate Report No. 101 - 228, page 3399, "Because ozone is not a local phenomenon but is formed and transported over hundreds of miles and several days, localized control strategies will not be effective in reducing ozone levels. The bill, thus, expands the size of areas that are defined as ozone nonattainment areas to assure that controls are implemented in an area wide enough to address the problem." The FCAA Amendments did provide the ability to exclude portions of the entire MSA or CMSA prior to designation, if the state conducted a study that the EPA agreed proved that the geographic portion did not contribute significantly to violation of the NAAQS.

Redesignation has not occurred for any portion of the HGA nonattainment area, and is not currently being considered. For existing areas currently included within a nonattainment area, the specific area must be redesignated as attainment to be removed from a nonattainment area. FCAA, §107(d)(3), provides that the EPA may not redesignate a nonattainment area, or a portion thereof, to attainment unless several criteria are met, which include: a determination that the area has attained the NAAQS; there is a fully approved SIP for the area; there is a determination that the improvement in air quality is due to permanent and enforceable reductions in emissions; there is an approved maintenance plan for the area; and the state has met all requirements for the area under FCAA, §110 and Part D.

However, even if a specific area within the HGA nonattainment area was redesignated by the EPA as attainment for ozone, reductions associated from all adopted ozone control strategies would still be necessary because of the requirements of FCAA, §107(d)(3) and §175A, which require maintenance plans for all redesignated areas. The maintenance plan must include the measures specified in §107(d)(3) and any additional measures that are necessary to ensure that the area continues to be in attainment with the NAAQS for ten years after the redesignation. Eight years after the redesignation, the state is required to submit an additional revision to the SIP for maintaining the NAAQS for ten years after the end of the first ten-year period.

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies.

At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The commission has conducted air quality modeling and upper air monitoring that found regional air pollution should be considered when studying air quality in the Texas ozone nonattainment areas. This work is supported by research conducted by OTAG, the most comprehensive attempt ever undertaken to understand and quantify the transport of ozone. Both the commission and the OTAG study point to the need to take a regional approach to controlling air pollutants.

The commission continues to believe that, in most cases, the most effective method of achieving attainment in the HGA nonattainment area is the implementation of controls and strategies throughout the nonattainment area. Much of the HGA control strategy is based on this concept. However, 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 areas of the state. Because of this flexibility, the commission can determine where emission reduction measures are most needed and where emission reduction measures will be most effective in order to demonstrate attainment. Based on estimated population, estimated population growth, and estimated emissions developed using EPA-approved methodologies, the commission has concluded that the sum of the 2007 projected emissions from lawn and garden service equipment in Chambers, Liberty, and Waller Counties is less than 3% of the total lawn and garden service equipment projected emissions in the eight-county area. The effect of shifting lawn and garden service equipment emissions in these three counties has been modeled, therefore the commission believes that including these counties in the adopted rule will have practically no beneficial impact on peak ozone levels. Further, these three counties are primarily rural in nature thus, the commission believes that lawn and garden service equipment emissions are more widely dispersed geographically and are unlikely to significantly influence the urban ozone plume. The commission does not, however, believe it is appropriate to exclude Montgomery County.

Based on the January 1, 2000 population estimates compiled by the Texas State Data Center, the population of Chambers County is 26,409; Waller County is 29,208; and Liberty County is 68,687, for a total of 124,304. The estimated population of the remaining counties in the HGA nonattainment area is Brazoria, 236,372; Galveston, 249,898; Montgomery, 295,263; Fort Bend, 356,555; and Harris, 3,275,630, for a total of 4,413,718. The total estimated population of the entire HGA nonattainment area is 4,538,022. Thus, the estimated population of Liberty, Chambers, and Waller Counties is 2.74% of the population in the HGA nonattainment area.

The total emissions from all of the HGA nonattainment counties for lawn and garden service equipment is 1.16 tpd of NO_x and 41.2 tpd of VOC. The estimated actual emissions from lawn and garden service equipment for Liberty County is 0.0 tpd of NO_x and 0.548 tpd of VOC; for Chambers County it is 0.0 tpd of NO_x and 0.235 tpd of VOC; and for Waller County it is 0.0 tpd of NO_x and 0.202 tpd of VOC. The effect of shifting these emissions will result in equivalent emission reductions of 0.0 tpd of NO_x and 0.16 tpd of VOC in Liberty County; 0.0 tpd of NO_x and 0.07 tpd of VOC in Chambers County; and 0.0 tpd of NO_x and 0.06 tpd of VOC in Waller County. Based on estimated population, estimated population growth, and emissions estimates developed using EPA-approved methodologies, the commission believes it is appropriate to exclude Chambers, Liberty, and Waller Counties from the adopted rule.

The same is not true, however, with respect to Montgomery County which the commission believes should be retained in the adopted rule. Based on estimated population, estimated population growth, and emissions estimates developed using EPA-approved methodologies, the commission concluded that the sum of the 2007 projected emissions from lawn and garden service equipment in Montgomery County is 11.8% of the NO_x and 13.6% of the VOC of the total lawn and garden service equipment projected emissions in the eight-county area. The effect of shifting lawn and garden service equipment emissions in this county has been modeled, therefore the commission believes that retaining Montgomery County in the adopted rule will have a measurable, beneficial impact on peak ozone levels. Montgomery County is not primarily rural in nature, thus lawn and garden service equipment emissions are not as widely dispersed geographically as those same emissions are in Chambers, Liberty, and Waller Counties, and are likely to influence the urban ozone plume. Based on data compiled by the Texas State Data Center, Montgomery County is the third largest county in the HGA nonattainment area with an estimated population of 295,263, or about 6.51% of the population in the HGA nonattainment area. Based on population, the county is over two times as large as Liberty, Chambers, and Waller combined. Its NO_x emissions are significantly greater than the three counties being excluded from the adopted rule. The estimated actual emissions from lawn and garden service equipment in Montgomery County is 0.137 tpd of NO_x and 5.607 tpd of VOC. The effect of delaying these emissions is expected to result in equivalent emission reductions of 0.03 tpd of NO_x and 1.68 tpd of VOC.

Sierra-Houston resubmitted comment letters dated August 2, 1999, January 31, 2000, and February 24, 2000, concerning already-completed rulemakings and SIP revisions which Sierra-Houston had initially submitted during the comment period for these previous rulemakings and SIP revisions.

These comments were addressed in the ANALYSIS OF TESTIMONY section of the preambles to the earlier rulemakings and SIP revisions which were published in previous issues of the *Texas Register*.

GEHC, MCA, and 13 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 emission specifications. GHASP commented that all grandfathered facilities should be investigated to be certain that they are properly so designated since many of these facilities have made modifications. State Senator Carlos Truan commented that a problem with the proposed rules is that they do not deal with grandfathered facilities and that the commission has let these facilities avoid permitting through the use of standard exemptions.

The commission made no change in response to the comments. The adopted rules that apply to facilities, for example the Chapter 117 NO_x requirements and the Chapter 115 VOC requirements, apply to both permitted and non-permitted ("grandfathered") sources in HGA. The commission agrees that it is appropriate to pursue cost-effective measures to reduce pollution; however, any such measures must be within the statutory authority of the commission. The TCAA does not authorize the commission to require grandfathered sources to obtain permits in order to operate, or to prohibit operation of those sources. A grandfathered facility is one that existed at the time the Texas Legislature amended the TCAA in 1971. These facilities were not required to comply with (i.e., were grandfathered from) the then new requirement to obtain permits for construction activities. Whenever a grandfathered facility is modified (as that term is defined in the TCAA) then it is required to comply with the TCAA permitting requirements in order to be authorized to construct and operate that modification. If a grandfathered facility has never been modified, it continues to be authorized by the TCAA to operate without a permit. Further, the definition of "modification" specifically excludes changes to facilities that are authorized by an exemption, i.e., any facility, including a grandfathered facility, can make a change using a commission exemption (now permit by rule) and this change is not considered to be a modification that would trigger the permitting requirements of the TCAA. During the 76th Texas Legislative Session in 1999, the issue of grandfathered sources was addressed by two different legislative programs. Senate Bill 766 was passed which provided a framework for a voluntary permitting program for grandfathered sources under the TCAA, and SB 7 which requires mandatory permitting and emission reductions from electric generating facilities. The commission continues to pursue enforcement action against companies who are not in compliance with the permitting requirements of the TCAA. However, SB 766 does provide for amnesty from enforcement for facilities eligible to participate in the voluntary emission reduction permit program as long as a permit application is received before the TCAA deadline of September 1, 2001.

LWV-TX commented that the rule, while it may cause a public backlash, allows enough time for the replacement of old equipment with newer, less polluting equipment by homeowners and lawn services.

The commission revised the adopted rule to allow domestic and emergency use of use lawn and garden service equipment powered by small, spark-ignition engines 25 hp and below from April 1 to October 31 of each year. The adopted rule specifically prohibits commercial operators and persons not exempt under §114.452(b) from using the lawn and garden service equipment during the specified time periods unless they submit an emissions reduction plan by May 31, 2003 that will provide equivalent reductions of NO_x and VOC. The executive director may allow plans to be submitted after May 31, 2003. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division. The commission agrees that the April 1, 2005 compliance date should provide enough time for commercial operators to make the necessary adjustments in order to comply with the rules.

Sierra-Houston and seven individuals commented that they believed that this rule should include a complete ban on leaf blowers. Sierra-Houston added that leaf blowers create noise and water pollution and that users of leaf blowers blow organic debris into the storm sewer and that this will load up streams with organic matter that will cause oxygen depletion and fish kills. One individual commented that if this rule is applied to the HGA, then there should be a rule to limit the use of drive-through windows. One individual commented that a ban should be placed on all gasoline-powered golf carts in favor of electric. Two individuals commented that they do not like loud lawn equipment in the morning. TAB, Lynn's, Harris Landscape, and TNLA commented that the rule would increase noise pollution because it compresses the work day.

Because the proposed rule did not address drive-through windows, or gasoline powered golf carts, the commission is unable to revise the rules at adoption to include limitations to address these issues. Further, the proposed rule did not address a ban on leaf blowers; therefore, the commission is unable to adopt such a ban at this time. This adopted rule will prohibit the use of leaf blowers and equipment like it, until afternoon during the specified time periods. The commission realizes that idling vehicles are contributors of emissions and is concurrently adopting a rule which will limit the amount of time that very large, heavy-duty vehicles may idle. Leaf blowers are noisy; however, the commission does not have the statutory authority to address issues related to noise pollution. This rule will shift lawn maintenance activity into the afternoon hours and should cause a decrease in lawn maintenance noise in the morning hours. The commission disagrees that the compression of the work day will increase noise pollution.

One individual commented that there should be "significant" emission reductions from this rule if it is to be implemented, and three individuals wished to know what benefits would be gained by this proposal. OPEI, PPEMA, Texas Lawn and Landscape, and three individuals commented that limiting lawn mower emissions would result in small reductions of NO_x. PPEMA and one individual commented that this rule is not necessary in terms of the amount of pollutants that are being reduced. Ray's and six individuals commented that they would like to know what the percentage of improvement would be attributable to the proposed rule.

The commission believes the emission reduction that will result from these rules is significant. The commission estimates that this measure will achieve a minimum of 0.23 tpd delay of NO_x until after noon. There will also be a 12.4 tpd delay in VOC emissions until after noon. Because the emission of NO_x and VOC, both precursors to the formation of ozone, will be delayed until after noon, this delay will lead to a reduction in ozone that is equal to approximately 4.6 tpd NO_x reduced. The HGA area exceeds the federal ambient air quality standard for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The CARB has stated that "using a commercial chain saw powered by a two- stroke engine for two hours produces the same amount of smog-forming hydrocarbon emissions as driving ten 1996 cars about 250 miles each." According to EPA estimates, in many large urban areas, pre-1997 lawn and garden equipment accounts for as much as 5% of the total man-made hydrocarbons that contribute to ozone formation. The commission expects that reducing emissions from these small engines will help to alleviate the formation of ground-level ozone resulting in a decrease of air pollution-related health problems for urban residents.

One individual commented that proper maintenance of lawn equipment must be part of the solution.

The commission agrees with this comment and encourages operators of this equipment to practice regular maintenance. Poor maintenance of internal combustion engines can contribute to emissions of VOC and NO_x.

One individual asked why the commission chose to implement the lawn mowing rule in 2005, rather than earlier.

The commission chose to implement the lawn equipment time-shift rule in 2005 so that this rule may coincide with the new Division 9, Houston/Galveston Construction Equipment Operating Restrictions; to Subchapter I, Non-road Engines; Chapter 114, Control of Air Pollution from Motor Vehicles that is being adopted concurrently with these rules. Additionally, by having the rules take effect in 2005, this allows commercial operators and persons not exempt under §114.452(b) to adjust to the impending change in schedule. That is, commercial operators can determine whether they would like to alter their fleets to include manual or electric-power lawn and garden service equipment or submit an emission reduction plan under §114.452(c).

One individual commented that the rule is only being proposed because the companies being regulated do not have influence over the commission.

Industry of all size, as well as individuals, are being asked to lower emissions for the benefit of cleaner air in the HGA area. For instance, large industries such as power companies, will be required to reduce their NO_x emissions by 90%. Individuals will also be required to conform to lower speed limits, and to comply with Inspection/Maintenance programs for automobile exhaust systems.

Pate and Pate and CAP commented that the rule has not been attempted anywhere in the United States. They also commented that the rule will result in an average increase of 10% in their payroll and that the rule may cause many workers to become unemployed. Missouri City commented that this rule will create higher costs associated with the change in work schedule and the hiring of part-time employees. TNLA, Harris Landscape, and Lynn's commented that landscape workers often hold two jobs and this would not allow them to work at their night jobs. ACEC, AOPE, BCCA, TNLA, CSE, EETC, RDC, TSDA, OPEI, PPEMA, DACC/Dayton Pipe, NASA, Lynn's, Bio Energy, Frazier, Mustang Mowing, Spring Valley, ExxonMobil, Harris Landscape, Wakefield, Ray's, Wiccacon, Johnson Saw, Texas Lawn and Landscape, and 27 individuals commented that they felt that the rule proposal would have too much of a negative impact on the lawn mowing industry. TNLA and Harris Landscape added that this proposal could create an unfair competitive advantage for those who choose to ignore it. TAB commented that the rule would give a competitive advantage to doing business outside of HGA. ExxonMobil commented that it does not support the use of temporal restrictions on the use of non-road equipment such as lawn service equipment and that the rules would be extremely disruptive to business and industry in the region and will place the region at a competitive disadvantage relative to other parts of the country. One individual requested to know the "economic trade-offs" involved in the rule proposal, and the "major assumptions used" for the proposal. Mustang Mowing and two individuals commented that sales tax revenue will be lost. RDC, TNLA, Harris Landscape, Lynn's, Minnesota City, Pate and Pate, Mustang Mowing, Wakefield, Ray's, and four individuals commented that this rule will leave less time for companies to work, thus cutting into their profits earned. RDC commented that they would be forced to cut wages or increase prices to consumers. Greenscape commented that they begin mowing at 7:30 a.m. and finish near 4:30 p.m. each weekday, with employees taking several breaks during the hottest part of the day. This schedule meets the budgets of their customers and provides employees with full time employment. Harris County Judge Robert Eckels and City of Houston Mayor Brown commented that the rule does not reduce pollution in a cost-effective or acceptable manner for the residents, business, or government in the Houston region. Greenscape commented that equipment has been purchased over the years with an eight-hour day as the basis for the costs. Losing half a day will cut productivity and sales. Hiring more employees would be more than their limited profit margin could bear and that they could be forced out of business. Financial committments made to creditors would likely not be met if the time restrictions were implemented. The rule sacrifices the health of landscape businesses (with statewide sales of nearly $4.4 billion per year) as well as their employees for the convenience of others. TSDA, TNLA, Harris Landscape, Lynn's, Wakefield, and two individuals commented that the basis and analysis for the rule is flawed.

Although it is true that this strategy has not before been implemented, the commission believes that it is reasonable, based on known and credible science, to regulate the use of lawn and garden service equipment powered by small, spark-ignition engines 25 hp and below from April 1 to October 31 of each year in order to meet the federal ozone NAAQS.

The commission disagrees that this strategy is unproven, untested, or is not based on sound science. It has been well established by the scientific community that emissions of NO_x released during the late morning hours contribute more to ozone formation than do emissions at other times of the day. This is because ozone is formed through chemical reactions between natural and man-made emissions of VOC and NO_x in the presence of sunlight. Higher ozone levels occur most frequently on hot summer afternoons, and the critical time for the mixing of NO_x and VOCs is early in the day. By delaying the hours of operation for lawn and garden service equipment and delaying the release of NO_x emissions until after noon during the ozone season, the NO_x emissions will not mix in the atmosphere with other ozone-forming compounds until after the critical mixing time has passed. Therefore, production of ozone will be delayed until later in the day when optimum ozone formation conditions no longer exist, ultimately reducing the peak level of ozone produced.

Consequently, and understanding that a certain amount of lawn and garden service equipment emissions are unavoidable, the commission believes that delaying NO_x emissions from the morning hours until after noon, during the prime ozone forming months, is an effective and well- reasoned strategy that uses good science to good effect.

The commission recognizes that compliance with this rule may cause losses in productivity and revenue and require commercial operators to seek creative solutions in order to remain competitive. The commission also recognizes that members of the affected workforce may choose to seek other jobs with different hours. However, the commission anticipates that affected companies will find and make the necessary adjustments to minimize these impacts, especially considering the far more substantial impacts that would result from the failure of the HGA area to attain federal air quality standards that these rules are designed to help achieve. Although many of the rules included in the current SIP attainment strategy will not be easy to implement and will cause many of the affected entities to adjust normal operations, these rules are necessary in order to demonstrate compliance with the ozone standard.

As with any rule, the commission expects that there will be noncompliance by an undetermined number of regulated entities. The commission believes that most commercial operators will willingly comply with the regulation. Those who do not will be subjected to the appropriate enforcement procedures. Economic gain as a result of the violation is a factor in setting penalties.

The adopted rule includes an option for commercial operators to submit an emission reduction plan that, if approved, will allow the operator to use the prohibited equipment in the morning hours. The commission believes that this flexibility will enable commercial operators to remain competitive. Further, the adopted rule does not ban all work in the morning hours, rather, it prohibits the use of certain equipment. Commercial operators will be able to use electric or manual powered equipment before noon. This rule will result in the equivalent of approximately 4.6 tons every day of NO_x-equivalent emissions reductions in the entire Houston/Galveston area. The commission believes this to be a significant reduction of harmful emissions in an area of the state classified as "severe nonattainment."

SBU Texas commented that it does not believe a serious attempt was made to determine the actual economic impact of the rule on small businesses. More needs to be done to justify the economic impact of the rules on small businesses. The rules should concentrate on implementing cost-effective measures that balance competing interests and proven methods that achieve results. Johnson Saw commented that the rule would seriously affect small business owners in the lawn and garden fields of operation. Bio Energy and Mustang Mowing commented that the lost hours for working will require the doubling of equipment and vehicles used which will cause prices to be higher, resulting in lost contracts, with the potential of bankrupting smaller companies. Mustang Mowing, Bio Energy, and two individuals added that larger companies would then pick up the business from the small businesses and that this rule will create monopolies as smaller lawn maintenance businesses find it impossible to compete. If there are not enough small businesses, there will not be enough companies to fill the demand for services. The monopolies could charge whatever they want for their services and they will be able to pay their workers less because of the large availability of unemployed workers. As a result of the loss of small businesses, sales tax revenue will be lost. One individual commented that the rule will hurt the small businessman. One individual commented that the rule would dictate the time that small businesses could start their business. Pate and Pate commented that the rule was rejected in California due to the burden it would have placed on small business. Johnson Saw commented that the rule would seriously affect small business owners in the lawn and garden fields of operation.

For several years, the commission's Small Business Assistance program has provided help to small businesses in the areas of permitting, compliance, and pollution prevention. Through this experience, the commission has gained an understanding of the needs of small businesses and the impacts that additional regulation can have on a small businesses. However, because of the need to obtain significant reductions in the HGA nonattainment area, the commission is unable to exempt small businesses from compliance with the rules. Even though a business may be small, it may not have a small amount of emissions, thus it is important that the emissions from small businesses be included in these rules and in the SIP in order for the HGA area to reach attainment. In order to provide as much flexibility as possible to all businesses that must comply with the rules, the commission has revised the HGA SIP to allow for the inclusion of economic incentive programs as a component of the HGA SIP for future consideration.

The proposal preamble acknowledged that there may be fiscal implications for small businesses as a result of the adoption and enforcement of the rules. The proposal noted that the economic impacts were not anticipated to be significant and that they would not likely extend beyond any impact due to the shift in work schedules and possible implications from work delays. The commission did state that additional employees might have to be hired or additional equipment might be purchased. The commission received comments stating that equipment for commercial lawn and garden operations is replaced regularly on a two- to four-year cycle. Based on this information, the commission believes that capital expenditures resulting from commercial operators' compliance with the modified rule are within the normal replacement schedule of their equipment and will not require the doubling of equipment or vehicles. For example, replacement of existing inventories with electric equipment will allow operators to continue their operations in the morning hours. The commission believes that replacement of equipment could allow commercial operations to continue to operate with the same number of employees after the 2005 implementation date. Further, additional comments indicate that the primary expense for these businesses is labor. The adopted rule allows commercial operators and persons to submit emission reduction plans by May 31, 2003, for approval by the executive director and the EPA no later than May 31, 2004. If an acceptable plan is submitted, commercial operators will be exempt from operating hour restrictions upon implementation of these rules in 2005 or thereafter, and will be able to operate during the restricted hours. This would also eliminate or reduce the need for increased labor costs. The executive director may allow plans to be submitted after May 31, 2003. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division. The commission believes that these options will allow small businesses to continue to compete with larger operations. These alternatives would enable small businesses to take advantage of economic incentive programs which are developed in the future. The commission will continue to work with small business representatives to identify options for compliance which may currently exist or which may become available in the near future.

Lynn's, TNLA, NASA, City of Simonton, Society of St. Vincent De Paul, Pate and Pate, Harris County Judge Robert Eckels, City of Houston Mayor Brown, BCCA, Harris Landscape, Pampered Lawns, Personal Expressions, and nine individuals expressed concern for lawn maintenance worker's general welfare. NASA expressed concerns for the safety and health of its onsite personnel since their workers would be working in the hottest part of the day. The City of Simonton, Society of St. Vincent De Paul, and RDC commented that the rule would have workers trying to maintain the same number of properties in half the normal time during the hottest part of the day and this would put the workers at a serious health risk. TNLA commented that the rule would require employees to work in excessive heat. TAB commented that workers would be subject to heat exhaustion. AAA expressed concerns about stress on crews due to hot temperatures, not only during the summer months but year round. Working after daylight hours will increase the chance of accidents. Cornelius commented that workers will be at a greater risk of heat stroke and that, according to OSHA (the Occupational Safety and Health Administration), employers should schedule these types of jobs for the cooler part of the day. This is a point widely taught in employee training meetings on preventing heat stress. Excalibur and Pate and Pate commented that the proposed workday shift poses an adverse health and safety threat to workers and that shifting work to the evening hours is irresponsible and unnecessary and poses a tremendous threat to the safety of workers and the public. Lynn's commented that landscape employees will suffer in terms of health if they have to start work at noon during daylight savings time. Mustang Mowing commented that the rules will result in increased incidences of dehydration, heat exhaustion, heat stroke, and skin problems related to mid-day sun exposure, including but not limited to melanoma. Spring Valley commented that the 125 part per billion, one-hour ozone standard is a health based standard and that no analysis was presented on the risks to human health and safety of operating lawn service equipment in the heat as required by the rule. The City of Simonton commented that the proposed rule is not reasonable and is dangerous to the health of workers. ED commented that this strategy fails to recognize that workers start work at dawn and quit at two or three to avoid hot temperatures. BCCA commented that it is concerned that the shift of this vigorous outdoor activity to the late afternoon and early evening hours present a safety hazard to lawn service workers. Greenscape commented that restrictions on hours of operation would be hard on employees and would cause an increase in costs for consumers since the health risks would require higher prices to cover the potential risks. RDC commented that lawn maintenance workers would experience health risks. One individual commented that there would be an increased risk of skin cancer for workers if they are obligated to perform their duties after 12:00 p.m. NASA, AAA, ED, RDC, BCCA, REI, OPEI, AOPE, TSDA, EETC, TNLA, TAB, CSE, City of Galveston Public Works, ExxonMobil, Phillips 66, Bell, Cornelius, Pate and Pate, Mustang Mowing, Spring Valley, Beasley, Lynn's, Wakefield, Missouri City, Harris Landscape, Briggs & Stratton, Ray's, Wesly, Wiccacon, Texas Lawn and Landscape, and 73 individuals commented that proposing an operating delay on lawn equipment until after 12 p.m. during the hottest months of the year would be unhealthy, especially for the elderly and/or infirm.

The commission agrees that this rule could negatively affect some in the lawn care industry in terms of working conditions. The commission recognizes that this rule may result in increased exposure to elevated temperatures, increased fatigue, and perhaps increased health care costs for employers and employees. However, operators of lawn equipment would be expected to take all necessary measures to protect their health and safety and educate themselves about potential risks as the commission presumes they do currently. The ultimate responsibility of the commission in terms of this rule is to maintain and improve the air quality and public health in the HGA. This rule would do that by creating a reduction in NO_x equal to approximately 4.6 tpd. These reductions are a necessary measure for successfully demonstrating attainment. While high temperatures can be dangerous to many in the Houston/Galveston area, every citizen in the area, especially asthmatics, the very young, and the very old, are vulnerable to the effects of ground level ozone. The commission is aware of the economic and other difficulties this rule will impose on businesses and individuals, and is adopting it with an extended compliance schedule so that lawn and maintenance businesses may supplement their equipment with electric or manual powered units or develop an emissions control plan.

TNLA, Harris Landscape, Lynn's, Mustang Mowing, Excalibur, Pate and Pate, TCSE-HC, and two individuals commented that the restriction would have a negative economic impact on the minority community employed in the lawn service industry. CAP, Lynn's, BCCA, OPEI, Spring Valley, Harris County Judge Robert Eckels, City of Houston Mayor Brown, and 13 individuals expressed concern for the low-income community employed in the lawn service industry. TNLA commented landscape workers often hold two jobs so this would impact the ability of these workers to continue in the second job and that the proposal would place an undue burden on the Hispanic community because 85-90% of the landscape workforce is Hispanic. Employees of landscape firms are semi-skilled laborers for whom a day or week or no work may mean the difference between living above or below the poverty line. Spring Valley and CAP commented that the proposed rule does not contribute to attainment of the ozone standard at the lowest economic and social cost because the proposal places a significant burden on many of HGAs most vulnerable workers. Mustang Mowing commented that the proposed ban could have widespread and negative effects on unskilled workers and on minority workers. Two individuals commented that pay would be cut in half for workers. Excalibur and Pate and Pate commented that the workday shift would fall disproportionately on the minority community and that minority families will feel a disproportionate impact. Seven individuals commented that the restriction would have a negative economic impact on the minority and/or low-income community employed in the lawn service industry. BCCA commented that it is concerned that the impacts of the rule will fall disproportionately on small and historically disadvantaged business owners. The commission maintains that the rule as adopted will not have a disparate impact on persons based on income level, race, color, or national origin. The basis for the rule is protection of human health and the environment, and shifting emissions from lawn and garden service equipment from 6:00 a.m. to 12:00 p.m. has been demonstrated to provide benefits in reducing ozone formation. Although it is not clear what, if any, legal standard the commentors allege the commission would violate in adopting the rule, some state that the rule would "disproportionately impact" minorities. This is clearly a reference to Title VI of the Civil Rights Act of 1964. In order for the commission to be shown in violation of Title VI, a disproportionately negative impact to minorities must be shown. As for potential negative impacts of the rule, these are clearly borne equally by all commercial operators and their employees governed by the rule without any differentiation by race, color, or national origin. The ultimate responsibility of the commission with these rules is to maintain and improve air quality and public health in the HGA area. This rule would do that by creating a reduction in NO_x equal to approximately 4.6 tpd. These reductions are a necessary measure for successfully demonstrating attainment.

The adopted rules provide that commercial operators can submit an emission reduction plan, that if approved, will enable the operators to use the prohibited equipment during the morning hours. The commission received comments stating that equipment for commercial lawn and garden operations is replaced regularly on a two- to four-year cycle. For example, this would allow operators to replace a substantial portion of their current inventory with electric equipment prior to the 2005 rule implementation date. Because the adopted rules do not prohibit all lawn and garden service activities, just the use of certain equipment, during the morning hours, commercial operators would be able to use the replaced equipment in the morning. This would reduce any negative impacts on employees.

Lynn's, Spring Valley, Harris Landscape, Ray's, and four individuals commented that this rule will cut into the "family time" of lawn and garden workers because these workers will have to spend more hours away from home working to make up for the time they will lose between 6:00 a.m. and 12 p.m. TNLA, Excalibur, Pate and Pate, and AAA commented causing workers to work into the evening hours will have an impact on the time that can be spent with their families. Excalibur and Pate and Pate commented that workers might choose to leave the industry or be forced into unemployment to avoid the extended hours. CAP, Harris County Judge Robert Eckels, and Spring Valley commented that the proposed rule does not contribute to attainment of the ozone standard at the lowest social cost because the proposal places a significant burden on many of HGA's most vulnerable workers. TAB commented that thousands of individuals who are accustomed to being at home with their families in the evenings would no longer have that option causing a tremendous negative impact on those families.

The commission recognizes that these rules may initially cause certain disruptions to the personal and social lives of affected employees, however the rules have been revised to provide flexibility for commercial operators. The adopted rules do not prohibit all lawn and garden services from being done in the morning hours, rather it prohibits the use of lawn and garden service equipment that is powered by small spark ignition engines of 25 hp or less. Work can still be done in the morning for activities that do not require the use of the prohibited equipment or electric or manual powered equipment may be used. Further, commercial operators may submit an emission reduction plan that, if approved, would allow the commercial operator and its employees to continue to work in the morning hours using the prohibited equipment. The restriction on hours of operation of certain lawn and garden service equipment is an important component in the overall strategy to reduce peak ozone levels to enable the HGA area to attain federal ozone standards. The area's failure to attain these standards will significantly impact the area economy, and therefore the quality of life of its citizens and communities.

GEHC, Cornelius, Wakefield, and 15 individuals commented that limiting lawn mower emissions would result in only small reductions of NO_x, and that the real source of most emissions was large industry. One individual commented that their mowing does not have the same effect as the pollution created by refineries in the Pasadena area. PPEMA commented that lawn and garden equipment engine are minor contributors to the VOC and NO_x inventory in the HGA, and that NO_x emissions from two-stroke handheld products are extremely low. TSDA commented that it is not appropriate to group lawn and garden equipment emissions with other types of equipment, like construction equipment. According to EPA, four-stroke lawn and garden engines account for only 1% of the total VOC emissions, which is far less than what was estimated in the proposal. TSDA noted that all small engines account for less than 1% of all hydrocarbons in the air. TSDA disagreed with the preamble statement based on CARB data that a chain saw running for two hours would produce more hydrocarbons than ten 1996 cars driving 250 miles each. TSDA stated this is physically impossible since a chain saw would use about two pints of gasoline and the cars would use about 100 gallons. No engine burning two pints of gasoline could out pollute 100 burned gallons of gas.

The commission agrees that the largest stationary sources of NO_x are point sources such as power plants and refineries. However, non-road mobile sources are also significant contributors of NO_x emissions and are a factor to be considered in reaching attainment. Lawn and garden equipment accounts for approximately 41 tpd of VOC. Small engines are the largest VOC emitters in the non-road category. Lawn and garden equipment accounts for 37% of the 2007 HGA eight-county area non-road VOC total and recreational boating accounts for an additional 23% on weekdays, and on weekends their share is much higher. This total includes emissions from four-stroke and the higher emitting two-stroke engines. The other 40% is spread among many categories. The 41.2 tpd of VOCs from lawn and garden equipment account for approximately 6.5% of the total anthropogenic eight-county VOCs. This rule will result in a reduction in ozone that is equal to approximately 4.6 tons per day of NO_x emissions and 12.4 tpd in VOC emissions for the HGA nonattainment area during the specified time period. The CARB has stated that "using a commercial chain saw powered by a two-stroke engine for two hours produces the same amount of smog-forming hydrocarbon emissions as driving ten 1996 cars about 250 miles each." Model year 1996 cars are equipped with advanced fuel injection systems and sophisticated three-way catalysts that enable the cars to burn nearly all of their fuel, and the catalyst to oxidize a large fraction of what is not consumed. A two-stroke chainsaw, with a simple carburetor, low- compression ratio, and no catalyst, can emit a proportionally vast amount of VOC as an unburned mix. According to EPA estimates, in many large urban areas, pre-1997 lawn and garden equipment accounts for as much as 5% of the total man-made hydrocarbons that contribute to ozone formation. The commission expects that reducing emissions from small engines will help to reduce the formation of ground-level ozone, thus resulting in a decrease of air pollution-related health problems for urban residents. The commission believes this to be a significant reduction of emissions in an area of the state classified as "severe" in terms of ozone nonattainment. By shifting the hours of use for handheld and non-handheld spark-ignition lawn and garden service equipment until after noon, NO_x emissions from such equipment will not mix in the atmosphere with other ozone-causing compounds until later in the day. The commission agrees that one individual's gardening routine does not emit the same types and/or amounts of pollutants as an oil refinery. However, when combined, the thousands of small spark-ignition engines used throughout the five specific counties in the HGA subject to the adopted rule do emit high levels of NO_x and VOCs. Additionally, it cannot be said that point sources will not be affected by the rules being adopted by the commission at this time. The commission is adopting rules which will require point sources in the HGA to lower emissions by 90%. The ultimate responsibility of the commission in terms of this rule is to maintain and improve the air quality and public health in the HGA. These reductions are a necessary measure for successfully demonstrating attainment in HGA.

RAQCG, AAA, SBU Texas, Mustang Mowing, BCCA, REI, Phillips 66, ExxonMobil, MCA, Public Citizen, Harris County Judge Robert Eckels, City of Houston Mayor Brown, GHASP, and 19 individuals believe the commission and/or EPA should require makers of lawn equipment to produce cleaner-burning engines. One individual commented that the commission should mandate the use of electric mowers in the HGA starting on October 1, 2003. BCCA commented that the commission and the EPA should work to develop and implement the next generation of lower-emitting lawn service equipment, and press for its early introduction into the Texas market. Three individuals suggested that distributors of lawn equipment should not be allowed to sell heavy polluting lawn equipment. One individual commented that this rule will stimulate lawn care companies to utilize clean-burning equipment. Sierra-Houston commented that the commission should require that some or all lawn and garden equipment be electric-powered.

The commission did not propose the control measures mentioned by the commenters and therefore cannot adopt them in this rulemaking. However, the EPA has adopted rules that require stringent emission standards for non-road small spark ignition handheld engines, such as trimmers, brush cutters, and chain saws. The second phase of the EPA rulemaking will reduce VOC and NO_x by an additional 70% beyond the current Phase 1 standards. The new standards will be phased in beginning with the 2002 model year. These new EPA rules will require manufacturers to develop engines that will emit significantly less emissions.

AOPE, TSDA, and three individuals commented that small, spark-ignition engines under 25 hp are being improved yearly and therefore believe that the rules are not necessary.

The commission agrees that small, spark-ignition engines under 25 hp are being improved but disagrees that this improvement justifies not adopting the rules. The commission continues to believe that the adopted rule is a necessary component of the HGA SIP demonstration. The commission cannot eliminate the adopted rule without an established, quantifiable, and enforceable replacement strategy that demonstrates proven ozone reductions equivalent to those achieved by these rules. The commission cannot do away with the operating restrictions because of the significant contribution of emissions from lawn and garden service equipment to the HGA area high ozone levels. NO_x is a key component in the formation of ozone. Because of this significant contribution that the equipment affected by these rules make to the HGA area ozone levels, it is essential that the small spark-ignition engine operating restrictions rules be implemented along with the other rules and measures included in this SIP revision in order for the HGA area to demonstrate attainment with the federal ozone standard. The restriction on hours of operation of non-road, spark- ignition engines 25 hp and under is an essential component to the overall strategy to reduce peak ozone levels to enable the HGA area to attain federal ozone standards.

AOPE commented that this rule would affect anyone who utilized a small engine such as plumbers and carpet cleaning companies.

The commission agrees that if plumbers and carpet cleaning companies use handheld equipment such as trimmers, edgers, chain saws, leaf blowers/vacuums, and shredders or non-handheld lawn and garden equipment such as walk-behind lawnmowers, lawn tractors, tillers, and small generators, they would be affected by the adopted rule.

Mustang Mowing and four individuals commented that electric lawn equipment is not a viable option. Three individuals commented that they felt that electric lawn equipment was an excellent alternative to gas-powered equipment. One individual stated that electric-powered lawn equipment costs too much in comparison to gasoline-powered equipment. One individual commented that their lawn servicing company which used push mowers, rechargeable weed eaters, and blowers purchased at Sears were less expensive than gas-powered equipment. The individual also commented that this equipment needed less maintenance and was less dangerous. Workers reportedly enjoyed the lighter weight of the equipment, and the customers were pleased with its performance.

The commission disagrees that electronic lawn and garden service equipment is not a viable alternative to small spark-ignition engines. This equipment can be purchased at most stores where gas- powered mowers can be found. This equipment is quiet, lightweight, and can perform the same duties as gas-powered equipment without any emissions of NO_x or VOC. The commission agrees that the initial purchase of electric-powered equipment is more expensive than gasoline-powered equipment.

However, the commission believes that this increase will be offset through the life of the equipment due to reduced fuel and maintenance costs. It is not a requirement of this rule that one purchase electric lawn equipment only. There are electric and manual powered versions of edgers/trimmers, lawn mowers, and chain saws.

Mustang Mowing, TLS, Ray's, City of Galveston Public Works, and five individuals commented that they did not understand how shifting the time period during which lawn equipment may be used will benefit air quality. CBE, MCA, TNLA, Harris Landscape, TAB, ED, OPEI, Lynn's, Sierra- Houston, Briggs & Stratton, and five individuals commented that the rules do not eliminate emissions, only shifts them to another time. ED commented that the proposal does not reduce total NO_x emissions. On ozone episodes when an air mass leaving HGA re-circulates back into the region, the benefits of the time shift in the release of the emissions may have little or no benefit. The commission should reevaluate this strategy under re-circulation conditions. Plus, the strategy will have little or no value in reducing ozone levels downwind of HGA. Sierra-Houston also commented on re-circulation and noted that this proposal could make ozone formation potential worse because emissions will not actually be reduced but will simply feed ozone precursor clouds with additional pollutants over time. MCA commented that there must be real emission reductions and that postponing emissions to later in the day is not a real reduction. Spring Valley, Mayor Louise Richman - City of Spring Valley, and one individual commented that these rules should only be applied during those months when it is absolutely necessary (i.e., limit the ban to days with high ozone generation potential). One individual commented that this rule should require that lawns only be mowed every other week. One individual asked why this ban would take place during daylight-saving time. One individual commented that the commission should allow mowing from September through May 11, 6:00 a.m. to 12 p.m.

It has been well established by the scientific community that emissions of NO_x released during the late morning hours contribute more to ozone formation than do emissions at other times of the day. This is because ozone is formed through chemical reactions between natural and man-made emissions of VOC and NO_x in the presence of sunlight. Higher ozone levels occur most frequently on hot summer afternoons, and the critical time for the mixing of NO_x and VOCs is early in the day. By delaying the hours of operation for certain lawn and garden service equipment and delaying the release of NO_x emissions until after noon during the ozone season, the NO_x emissions will not mix in the atmosphere with other ozone-forming compounds until after the critical mixing time has passed. Therefore, production of ozone will be stalled until later in the day when optimum ozone formation conditions no longer exist, ultimately reducing the peak level of ozone produced. The commission believes that delaying NO_x emissions from the morning hours until after noon, during the prime ozone forming months, is an effective and well-reasoned strategy that uses good science to good effect. To achieve the greatest benefit the rules must be in effect during the entire ozone season, because conditions can be present at any time during that season for the formation of high levels of ozone. The commission acknowledges that re-circulation occurs and can be a factor in escalating daily ozone levels in Houston. As re-circulation occurs, emissions are brought back into the HGA area on a daily cycle depending on meteorological events such as a land/sea breeze. As this cycle occurs daily, the time of day of the emissions makes little difference on whether the contaminants will be returned on the subsequent day. The intent of this adoption is to reduce the amount of time that sunlight has to react with ozone precursor gases on. Therefore, the commission believes that re-circulation is not a significant factor in the effectiveness of this adopted rule.

If the commission were to only permit the use of lawn equipment every other week throughout the entire day, or only on ozone action days, the emission reduction benefit of the rule would be diminished. The commission lacks sufficient historical data on ozone action day prediction, as well as the technology to improve upon prediction accuracies, to warrant changing the rules to only be enacted on ozone action days. That is, the time shift does not allow the use lawn equipment in the morning hours because this is the primary time during which ozone-forming emissions mix with sunlight to create ground-level ozone. It would also be difficult for commercial operators to comply with the rule if the time periods for compliance were different from week to week. It is important that the restriction on the use of lawn and garden service equipment be in effect everyday from April 1 until October 31 since this is when HGA experiences the greatest impact from ozone formation.

EPA commented that it understands that 100% rule effectiveness has been assumed for the proposed rule. Since this will take a substantial commitment of resources to approach that level of effectiveness, the commission should document the resources that will be allocated for this measure to achieve the full 100% projected benefit. Otherwise, a more realistic level of rule effectiveness should be assumed. The PIC commented that it questioned the likelihood of achieving 100% compliance with the proposed rule. The PIC seeks a clarification regarding whether the commission prediction that the lawn equipment operating restrictions will reduce NO_x emissions in the affected area by 0.58 tpd is based on a presumption of 100% compliance. If the commission prediction is based on 100% compliance, the PIC suggests that the estimated annual NO_x reduction be recalculated to reflect the potential for noncompliance with the rule. TNLA commented that the proposal is unlikely to have a positive impact since it relies solely on modifying the behavior of potentially over a million operators of outdoor power equipment and does not result in any actual emission reductions. TNLA noted that EPA discounts SIP emission credits based on rule effectiveness, compliance uncertainty and programmatic uncertainty so it is reasonable to assume that a rule based solely on behavior modification will not be given full SIP credit. TNLA again suggested adopting the California spill-proof gasoline container rule as a cost effective means of obtaining over 70 tpd of reduction of reactive organic emissions, which, in California, is expected by 2010.

The adopted rule does not prohibit the use of lawn and garden service equipment at a domestic residence by the owner of, or a resident at, the residence, nor does it prohibit use by a non-commercial operator. The adopted rule applies to commercial operators and persons who do not meet an exemption under §114.452(b). The adopted rule includes an option for commercial operators to submit an emission reduction plan that, if approved, will allow the operator to use the prohibited equipment in the morning hours. The commission believes that this flexibility will enable commercial operators to remain competitive and will encourage compliance with the rules. Further, the adopted rule does not ban all work in the morning hours, rather, it prohibits the use of certain equipment. Commercial operators will be able to use electric or manual powered equipment before noon. The commission believes that commercial operators will make the necessary adjustments required to comply with the adopted rules. The commission has re-evaluated the rule effectiveness for these rules and continue to believe that the rule effectiveness will be 100%, especially since the rules now apply only to commercial operators. The commission will enforce the rules using its existing enforcement program, including working with local programs to ensure the highest possible compliance rate.

TSDA, Wesley, and EETC commented that due to the fact that this rule does not allow the use of any type of lawn equipment before 12:00 p.m., except for manual and electric equipment, they cannot utilize natural gas-burning mowers which have very low emissions.

The commission agrees that natural gas-burning mowers have low emissions. However, any emissions from lawn and garden service equipment that is powered by small spark ignition engines of 25 hp or less, will contribute to the formation of ozone. Commercial operators may chose to lower emissions by other means based on the new provision in §114.452, which allows commercial operators to use the restricted equipment if they submit an approvable emission reduction plan that will reduce an equivalent amount of emissions. An acceptable plan might be one that is based on using natural gas-burning mowers during the restricted time period.

RAQCG, ED, CAP, TNLA, TLS, OPEI, PPEMA, TAB, TSDA, EETC, Sierra-Galveston, Sierra-Houston, Lynn's, Excalibur, La Porte, Pate and Pate, Spring Valley, Harris County Judge Robert Eckels, Harris Landscape, City of Houston Mayor Brown, Missouri City, State Representative Robert Talton, Wesley, and 27 individuals commented that the proposed rule would be very difficult, if not impossible to enforce, thereby being ineffective. Sierra-Houston commented that the rule is virtually unenforceable since the commission and local air pollution agencies do not have the investigators to ensure that the rules are enforced. County Commissioner Malcolm Purvis, asked who would be responsible for enforcing the rule, how the rule will be enforced, the cost of enforcement, and how many people this will require. Spring Valley commented that municipalities are concerned about requirements that their overworked and understaffed local police departments will be required to enforce the rule and asked if municipalities are not required to enforce the rule, what agencies will be responsible for enforcement? Lynn's commented that the rule cannot be enforced and therefore will not do any real good in reducing air pollution. TNLA commented that there is no reasonable way to enforce the rule and noted that when laws are considered to be excessively onerous by the public, they are usually ignored. PPEMA commented the rule would be difficult to enforce. TAB, Pate and Pate, and Excalibur commented that the rule is unenforceable and that enforcement would most likely fall to local governments which are lacking in funding and manpower. This will result in nonuniform enforcement, if there is enforcement at all. ED commented about the ability to enforce the rule since there are scores of independent lawn and garden companies in HGA. To enforce a rule concerning starting times for this work will require a lot of police issuing tickets and resources may be better spent preventing crime. One individual commented that this rule would create a new class of lawbreakers. Three individuals commented that new revenue would have to be raised to fund the enforcement of this new regulation. Mustang Mowing commented that extra money will have to be spent to enforce the ban, including extra police officers. This spending could be applied to other more useful measures of reducing pollution like better mass transit programs. Sierra-Galveston commented that the SIP calculates unrealistic NO_x reductions from a ludicrous restrictions like the lawn ban. People are going to mow their lawns whenever they please. Mustang Mowing and three individuals commented that having to raise new revenue to fund the enforcement of this new regulation would be problematic.

The commission agrees that the rule, as proposed, presented enforcement challenges for the commission, cities, and local programs. However, the commission believes that the adopted rule will be less of an enforcement challenge since it now applies only to commercial operators. The commission believes that these entities will take appropriate measures to comply with the adopted rules. As with all of its rules, the commission will enforce the requirements after the rule compliance date and take appropriate action for noncompliance situations. The rules are enforced by staff in the commission's regional offices, as well as local air pollution control programs. Local governments have the same power and are subject to the same restrictions as the commission under TCAA, §382.015, Power to Enter Property, to inspect the air and to enter public or private property in its territorial jurisdiction to determine if the level of air contaminants in an area in its territorial jurisdiction meet levels set by the commission. Local governments are not required to enforce commission rules but may sign cooperative agreements with the commission to enforce the rules under TCAA, §382.115, Cooperative Agreements. Local programs can also enforce commission rules without signing a cooperative agreement. The authority of local governments to enforce air pollution requirements is specified in detail in TCAA, §§382.111 - 382.115, and local governments can institute civil actions in the same manner as the commission pursuant to Texas Water Code (TWC), §7.351. The commission will work with local officials to ensure enforcement of the SIP and SIP rules. The commission has existing relationships with pollution control authorities in the City of Houston, Harris County, and Galveston County for enforcement of other commission rules. The agency will continue enforcement relationships with these entities and develop relationships with other local officials as needed to create effective enforcement mechanisms for the SIP and SIP rules. The commission expects to enforce this rule with existing personnel and does not anticipate any increase in enforcement costs.

Five individuals commented that this rule could interfere with their ability to comply with local lawn control rules which require their lawns to be maintained to certain standards.

The commission is not banning lawn maintenance activities altogether, merely shifting the time period during which lawn work may be conducted with small spark-ignition engines under 25 hp. There are alternatives to using this type of gasoline-powered equipment, including the use of electric or manual equipment.

One individual requested that the commission encourage stores to stock electric- and manual- powered lawn equipment. One individual commented that they cannot find a store from which to purchase manual mowers.

Electric and manual mowers are available at many of the major hardware stores. The commission supports the manufacture and sale of low- and zero-emission technology currently. The commission anticipates that stock of electric and manual powered equipment will grow as demand increases.

RAQCG, BCCA, REI, HARC CGS, Friendly Robotics, Bell, ExxonMobil, Houston MPO, Phillips 66, Spring Valley, Harris County Judge Robert Eckels, City of Houston Mayor Brown, Cornelius, and 14 individuals requested that the commission provide monetary incentives for the purchase of clean-burning lawn equipment. CAP, Harris County Judge Robert Eckels, and Spring Valley commented that the proposal should be deleted from the SIP and replaced with a publically acceptable alternative that is achievable and enforceable. This proposal should be included in the economic incentive programs that are being developed for HGA. Public Citizen commented that they would support the Carl Moyer program as is employed in California whereby an enforceable, market- based incentive program is utilized.

The commission agrees that economic incentive programs can potentially be an effective tool for achieving air quality. One such program is the Carl Moyer program in California. That program appears to be successful in providing flexibility to the regulated industry while still achieving reductions in air emissions. The California program is authorized by and funded through the state legislative process and such legislative approval does not currently exist for a similar Texas program. The commission will continue to try to identify economic incentives which it has authority to implement. Because the commission agrees that market-based incentive programs can be an important component in encouraging development of new technologies and / or greater or more cost effective emission reduction strategies, the commission has provided for the inclusion of economic incentive programs as a component of the HGA SIP in the future.

The commission acknowledges the recommendation for a Carl Moyer-type program to accelerate the development and introduction of emissions-reducing technology for small, spark-ignition equipment 25 hp and under, but must rely on the Texas Legislature for approval and grant funding to further such a project. The commission staff will continue to study issues, interim solutions, and the feasibility of implementing a similar state-wide pilot program.

In addition, local stakeholders in the HGA area have expressed an interest in the creation of programs designed to provide incentives for the achievement of earlier and/or greater reductions than anticipated from currently adopted control measures. Such incentive programs could be effective technology-forcing tools to obtain substantial innovation and ozone reductions in the most cost-effective manner possible. Possible components of one such program applicable to these rules could be the competitive provision of funds to entities operating both on- and non-road NO_x sources to assist in the incremental costs of cleaner equipment, which could encourage earlier implementation of new technologies, cleaner engines, and fuels. Other incentive programs could focus on tax incentives, subsidies, research and development, technological assistance, etc. The commission anticipates that such programs could be components of the HGA ozone nonattainment SIP, either as enforceable commitments, as potential future substitute measures based on per-ton reduction cost and total funding associated with the final scope of the programs, or as alternative methods of compliance with proposed control strategies.

SBU Texas commented it would support modifications of the proposal that would give businesses a choice, for example, limited use of equipment as proposed or the use of more efficient, less polluting equipment. Choices could bring about even less pollution by providing an incentive to buy newer, more efficient equipment. The proposed rules leave in place much of the older equipment to operate during permitted hours. Spring Valley commented that there is no flexibility in the proposed rule to allow development of alternative emission reduction plans to this mandate. TNLA, TSDA, EETC, Harris Landscape, Lynn's, Spring Valley, Houston MPO, and one individual commented that the lawn industry has not been offered the same opportunity to present alternative plans that every other regulated industry was offered. Metro recommended that an exemption be provided for those entities that produce an approved emissions reduction plan. TSDA commented that the rule should provide alternatives, including consideration of using propane or alternative fuels. Public Citizen, La Porte, Pate and Pate, and one individual expressed support for a plan whereby those that use alternative fuels (e.g., LPG, CNG), and/or cleaner-burning equipment be exempted from the rule.

The adopted rule has been revised to provide an option in §114.452(b) for commercial operators to submit an emissions reduction plan by May 31, 2003, which must be approved by the executive director and the EPA no later than May 31, 2004. If the plan is approved, a commercial operator would be exempt from the operating hour restrictions upon implementation of these rules in 2005, and would be permitted to operate during the restricted hours. The commission is requiring submission of the emissions reduction plans two years prior to the compliance date to allow adequate time for review of the plans, both by the commission and the EPA, and to allow the commission to ensure that the collective emission reductions achieved by the plans are equivalent to the ozone reductions achieved by implementation of the rules. In order to be approved, the plan must demonstrate NO_x and VOC reductions equivalent to those required by the rules being requested for exemption, and must contain adequate enforcement provisions. The executive director may allow plans to be submitted after May 31, 2003. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division. This alternative to submit an emission reduction plan would also enable commercial operators and persons to take advantage of an economic incentive program which is to be developed in the future. The commission will continue to work with industry representatives to identify options for compliance which may currently exist or which may become available in the near future. The commission does not believe it is appropriate to exempt users of alternative fuels or cleaner burning equipment from the adopted rules and instead have included the option to submit an emission reduction plan. An emission reduction plan could be submitted that includes the use of cleaner burning equipment, and alternative fuels, including propane.

Houston MPO commented that the rule should have the ability to create alternatives in order to offset the mandates. The mechanism to provide the creation of the offsets should be through the Voluntary Mobile Emission Program and/or Economic Incentive Program. TNLA, Harris Landscape, Lynn's, and 2 individuals suggested that the commission replace this rule with a voluntary program to lower emissions from this equipment. The EPA commented that because of the level of resources necessary, even if a more realistic rule effectiveness level is assumed, this program might be more appropriately implemented as a voluntary measure. RAQCG commented that the lawn equipment measures should be included in a voluntary emission incentive program. BCCA commented that the commission should develop a program which provides for voluntary emission reduction incentives instead of adopting the rule. For example, lawn service operators and citizens could receive a rebate for the incremental cost of electric or low-emissions lawn service equipment in exchange for scrapping old equipment, thus accelerating the turnover of newer technology in the region.

The EPA provides for the inclusion of voluntary programs or measures as part of the attainment demonstration, but limits the amount of emission reduction credit that may be claimed from such measures, due to the fact that the programs are not enforceable mechanisms. In accordance with EPA policy, the commission has included some voluntary programs as part of the HGA SIP. The Houston Galveston Area Council (HGAC) is the entity responsible for the development and implementation of these programs, which are detailed in the HGA SIP. The Voluntary Mobile Source Emission Reduction Program (VMEP) is part of the Houston-Galveston nonattainment area's attainment demonstration that the HGAC will be implementing. HGAC will be responsible for the development and implementation of all VMEP initiatives in the Houston-Galveston area. If this rule became voluntary it could not be counted as an enforceable measure obtaining emission reductions for the demonstration of attainment. As stated elsewhere in this preamble, the emission reductions associated with this rule are necessary for the attainment of the NAAQS in the HGA area. It is possible for voluntary measures to be made enforceable through agreements and in that case they can be counted toward the SIP. The commission encourages efforts to reach enforceable agreements as suggested by the representative for the Mayor of Houston, and looks forward to working with all interested participants. The commission does not believe it can eliminate the operating restrictions in the adopted rule because of the significant contribution that lawn and garden equipment makes to the HGA area ozone levels. Because of this significant contribution that the equipment affected by these rules make to the HGA area ozone levels, it is essential that the equipment operating restrictions rules be implemented along with the other rules and measures included in this SIP revision in order for the HGA area to demonstrate attainment with the federal ozone standard.

RDC, PPEMA, City of Simonton, Poulan, and ten individuals commented that the rule will harm homeowners. For instance, people will be left without service, or be forced to pay more for services. One individual commented that this rule will pose an unnecessary health risk to their family because they will have to breathe the fumes of the gardeners' machines in the evening.

The adopted rule does not require a total ban on the use of small spark-ignition lawn and garden service equipment, rather, it prohibits the use of this equipment from 6:00 a.m. until noon from April 1 until October 31. Further, commercial operators are able to use electric or manual powered lawn and garden service equipment and may submit an emissions reduction plan which would allow them to operate in the morning hours. Therefore, the commission does not believe that homeowners will be left without service. The commission agrees that increased costs for lawn service may be a result of this rule. However, it is more likely that lawn mowing companies will be able to accommodate the needs of all of their clients in a cost-effective manner by the time this rule is implemented in 2005. The commission believes that the ability to use electric equipment or an alternative plan will keep the need to perform lawn and garden work in the evening hours to a minimum.

HARC, CGS, and two individuals suggestioned that those in the HGA area use landscaping which requires less maintenance.

The commission supports the use of such techniques, also known as xeriscaping. The use of xeriscaping - utilizing plant life which is adapted to the weather conditions common to the region - saves money, water, time, and effort. Most relevant to this discussion however is the fact that lawns planted with particular grasses adapted to the weather of Texas can go for much longer periods of time without the need to be mowed, hence reducing the need for the use of gasoline-powered engines which contribute to ground-level ozone pollution.

Wakefield and three individuals commented that this rule should be applied to the entire state.

The commission appreciates the commenters' support for statewide applicability of the rules. The commission notes, however, that it is not obligated to adopt all rules statewide in order to satisfy its commitments under the SIP, nor is the commission required to do so under the FCAA. Three of the adopted measures contain emission reduction strategies that have been proposed for statewide applicability: California large-spark ignition engines; emissions banking and trading program (that portion of the adopted rule which relates to the trading of emission reduction credits and discrete emission reduction credits); and low-emission diesel fuel (that portion of the proposed rule which relates to on-highway fuel).

In evaluating whether to implement all of the rules statewide, the commission took into account many concerns, including, but not limited to, the need for the marketplace to be able to respond to regulation, the possible impacts on transport and distribution systems, the possibility of increased costs and financial burdens on regulated entities, and regional needs and issues associated with state-wide mandates. The commission analyzed where emission reduction measures are most needed and where emission reduction measures will be most effective in order to demonstrate attainment.

One individual commented that these rules are being set up to embarrass Texas and the Governor, and that the State Legislators and Congress should investigate these plans.

The commission disagrees with this statement. The commission intent is to comply with the timelines provided in 1990 FCAA amendments and subsequent EPA guidance for submitting rules to demonstrate ozone attainment in HGA. Accordingly, Texas has committed to adopting the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000.

One individual requested that an exemption be made for those people who could not mow after noon for health reasons.

The adopted rule exempts any use at a domestic residence by the owner of, or a resident at, that domestic residence and any use by a non-commercial operator.

One individual suggests that the commission study the strategies that California has utilized to control ground-level ozone.

The commission is aware of the ozone control programs utilized by the State of California and has one rule based directly on a CARB rule which sets emission standards for spark-ignition engines above 25 hp. That rule is being adopted concurrently with this rulemaking.

Greenscape suggested that a law should be passed to stagger the work times of commuters so that auto emissions would be reduced.

The commission does not have the statutory authority to adopt a regulation that would require the staggering of work times of commuters. However, HGAC is reviewing an option to use a voluntary program for a reduction in vehicle miles traveled (VMT) that could include such things as ride sharing, adjusting work hours, and other commuter options. Any reductions resulting from that program would be fully creditable to the SIP.

Dayton Pipe commented that it has over 13 acres of land to mow and maintain and that it would be hard to do that in four-hour days unless they opened at noon and worked until 8:00 p.m. One individual asked that those with many acres of land should be allowed to mow during the ban period.

The adopted rule prohibits commercial operators from using lawn and garden service equipment powered by small spark-ignition engines less than 25 hp from 6:00 a.m. until noon from April 1 to October 31. This prohibition does not depend on the amount of acreage being mowed. The adopted rule does not prohibit all mowing, only that which is done with the specified engine type.

AAA, Excalibur, TNLA, Lynn's, Harris Landscape, and six individuals commented that working during the night time to make up for lost morning hours is not feasible and insurance costs for businesses may increase.

The commission understands that there may be economic impacts such as increased insurance costs as a result of implementation of the adopted rule. However, the cost to all citizens of HGA, including the regulated community, will be significant if the area fails to comply with the FCAA ozone standards. The effective period of this rule runs concurrently with daylight savings time. This should help reduce potential risks associated with low visibility as much lawn and garden maintenance activity will still occur in daylight. The adopted rule does not prohibit all lawn and garden service work in the morning hours. Commercial operators will be able to use electric or manual powered equipment before noon. They can also submit an emission reduction plan, that if approved, will allow the commercial operator to use the prohibited equipment in the morning.

TNLA, Harris Landscape, and Lynn's commented that application of pesticide and fertilizers should not occur during the heat of the daytime.

This rule does not prohibit the application of pesticides or fertilizers during any part of the day unless they are applied with small spark-ignition lawn and garden service equipment powered by an engine of 25 hp or less.

Personal Expressions commented that the fuel used in the type of equipment covered under this rule is the source of harmful emissions. AOPE commented that the commission should utilize a plan which would mandate the use of cleaner-burning two-cycle engine oil.

The primary fuel for this type of equipment is either gasoline for four-stroke engines or gasoline mixed with lubricating oil for two-stroke engines. The gasoline used in four-stroke engines is not inherently dirty, and emission levels from those engines are more dependent on engine maintenance rather than the use of gasoline. The two-stroke is a higher emitting engine due to its speed of operation and the greater viscosity of the fuel. The two-stroke engine is useful because of its lighter weight and ability to operate in a variety of positions. The commission believes that electric equipment is a viable alternative to any gasoline equipment. The commission is not aware of any cleaner burning two-cycle engine oil that has been certified for use as a low emitting two-cycle additive.

TxDOT and one individual commented that an "emergency clause" should be included in the rule which would allow them to operate chain saws, generators, and gasoline-powered pumps in emergency situations (e.g., clearing fallen trees from the roadway, etc.).

The commission agrees with the commenters. An exception was added in §114.452(b) which allows the use of small, spark-ignition engines 25 hp and below to be used exclusively for emergency operations to protect human health and safety or the environment, including equipment being used to repair facilities, devices, systems, or infrastructure that have failed, or are in danger of failing, in order to prevent immediate harm to public health, safety, or the environment.

PPEMA, TNLA, and Cornelius commented that the commission should encourage state and national lawn and landscape associations to serve as training and educational resources in communicating with commercial and consumer user groups on recommended equipment use.

The commission supports the use of state and national lawn and landscape associations as sources of training and educational resources.

City of Galveston Public Works commented that improved traffic light coordination could offset the emissions from the construction ban, lawn mowing ban, and the 55 mph speed limit restriction.

The commission does not agree with this statement. The adopted rule will result in an equivalent of approximately 4.6 tpd of NO_x reduced. The new Division 9, Houston/Galveston Construction Equipment Operating Restrictions; to Subchapter I, Non-road Engines; Chapter 114, Control of Air Pollution from Motor Vehicles will result in an equivalent of 7.9 tpd of NO_x reduced. The SIP provision concerning the 55 mph speed limit will provide 12.7 tpd of NO_x emissions reductions. Improved traffic light coordination is a program that is being adopted as a plan to lower emissions in the HGA. The commission expects that the traffic light coordination measure will result in 0.8 tpd of NO_x emission reductions.

One individual commented that switching to electrically-powered lawn-care equipment can have as great an impact as reduction vehicular traffic.

Lawn equipment emits approximately one tpd of NO_x and 41 tpd of VOC emissions. The 2007 base case vehicular inventory shows 258 tpd of NO_x and 91 tpd of VOC. So, unless a very high percentage of electrification of lawn and garden service equipment is achieved, it is difficult to compare the effect of dealing with lawn care equipment versus autos. Nevertheless, the emissions from lawn and garden service equipment must be considered in adopting the emission reduction strategies for HGA and the commission continues to believe that the adopted rules are a necessary measure for a successful demonstration of attainment for HGA.

TSDA commented that this rule will limit the ability of dealers to service spark-ignition engines 25 hp and under. TSDA, Wiccacon, and one individual commented that this rule will not allow businesses to test and service equipment before noon.

The commission agrees that any service or maintenance activities that require the operation of small spark-ignition lawn and garden service equipment with engines that are 25 hp or below is prohibited by the adopted rule. Service activities that do not require operation of this equipment are not prohibited. Dealers will be able to submit emission reduction plans that, if approved, would enable them to operate the prohibited equipment during the morning hours.

TNLA, Harris Landscape, Lynn's, and one individual commented that manual labor cannot be economically substituted for gasoline-powered equipment.

The commission does not believe that manual labor will have to be used to substitute for gas- powered equipment. There are many other means which operators of small, spark-ignition engines can conduct their operations. For instance, electric equipment is a viable alternative to gasoline-powered equipment. Furthermore, the commission believes that companies will be able to develop approvable emission reduction plans that will allow them to continue their services in a cost-effective manner. Given the number of years that companies are being given to develop alternative means of supplying their services the commission feels that there should be no disruption in the level or quality of service.

REI, Harris County Judge Robert Eckels, and City of Houston Mayor Brown commented that the rule is technically infeasible. REI commented that the rule was proposed with less than a complete analysis of the economic feasibility. CAP commented that the rule may be technically infeasible or unnecessarily expensive. REI commented that the rule was proposed with less than a complete analysis of the possible environmental or economic disbenefit. ExxonMobil and BCCA commented that this rule exceeds federal mandates without proper justification. ExxonMobil commented that the commission failed to provide adequate scientific and technical justification, or economic analysis for the proposed ban on the use of non-road equipment. ExxonMobil believes there are technologically and economically feasible alternatives to the rules that provide comparable environmental benefits at a much lower cost to the public.

TNLA commented that the nursery/landscape industry is a $14.8 billion industry in Texas and that there are 2,300 landscape businesses affected by the proposed SIP revisions. The sales volume is $1.5 billion annually. TNLA provided data on the general profile of the industry: 56% sole proprietorships and 42% corporations; general labor constitutes almost 57% of the workforce; supervisory foreman make up 16% of the workforce; the average number of employees includes ten general laborers, two in-house sales staff, three supervisors or foremen, and one - two top management or owners; an average of nine employees per firm had turfgrass maintenance responsibilities and spent an average of 68% of their time performing those activities; the racial mix of employees statewide was 58% Hispanic, 36% Caucasian, and 6% African-American; almost 40% of the employees are between 21 and 30 years old; the pay scale is approximately $45,000 for managers, $28,000 for supervisors, $12,000-14,000 for installation, maintenance, or other types of labor, $17,000 for foremen and superintendents; most firms supply their employees with safety items like glasses, back supports, caps, shirts, gloves, and masks; 44% had sales of $100,000 or less while 24% had sales of over $500,000; on average, a landscape firm in Texas shows a 11.5% profit margin; insurance is a major expense; equipment costs totaled $32.5 million in 1993. Of this, vehicles represented 63% of the total with 22% for other equipment. On average, each landscape contractor spent approximately $11,600 on new equipment for the year.

TNLA commented that the proposal is excessively onerous to the landscape industry and disagreed with the commission statement that since the proposed rules did not require additional controls or new equipment, there would not be significant economic impacts to commercial operators beyond the shift in the work schedule and possible implications caused by potential work delays. TNLA noted that landscape equipment is generally replaced on a two- to four-year cycle so landscape companies can adapt to regulations requiring new technology as it becomes available with a minimal negative economic impact. The number one cost for landscape companies is labor which is increasingly unavailable. The industry is made up of very small, family owned businesses with narrow profit margins. The business is very competitive with price being one of the top two factors in selecting a landscape firm with service being second. Manual labor cannot be substituted for the use of power equipment, for example, a test in California showed that it took five times longer to clean a typical landscape using a broom and rake than it would with a power blower. TAB commented that the labor market is already suffering from shortages and many workers might be forced to leave the industry to avoid the non-traditional work hours. Bio Energy commented that the rule will cause the loss of employees who count on the hours. RDC commented that if employers have to hire more personnel to get the same amount of work done, employers will be forced to cut wages or increase prices.

TSDA commented that the commission would be cutting their selling season in half since the ban occurs during their top selling season. Frazier and Air Cooled Engine Company commented that they are opposed to the rule as it would greatly affect their business since it is a seasonal business and April 1 to October 31 includes the busiest part of their season and the busiest part of the day. RDC commented that the ban would put an unfair economic burden on the industry, both retail and wholesale business, along with the consumer and commercial user. TNLA, Lynn's, and three individuals commented that the time restrictions will leave less time to work and that will raise costs. NASA commented that the proposal will result in increased grounds maintenance costs as a result of a predicable decline in productivity due to asking workers to work in the hottest part of the day. AAA commented that the rule will increase costs related to lighting a job site and that this cost would be passed on to the customer.

TSDA commented that the economic impact on dealers would be significant. The average selling season for a dealer is between March and September. The proposal would prevent dealers from doing business during this critical time and would cut the selling season in half. The average dealer will lose an average of $480.00 per day due to unbillable time and unrealized average parts orders. This could be far more once overhead and other daily costs are added. This could mean millions in lost revenue for dealers. Since the average dealer usually sells between $100,000 and $500,000 gross, a loss of this type would be catastrophic, it would mean the difference between keeping their business open or going out of business. Mustang Mowing commented that their business will not be able to meet demand. Dayton Pipe commented that it does business with suppliers and customers who are outside of the HGA area and that a change in their operating hours would hinder their ability to converse with these suppliers or customers. Johnson Saw commented that the hours being restricted are the most important to all lawn and garden dealers and users of this equipment.

The commission is aware of the economic and other difficulties this rule will impose on businesses and individuals. In response to the comments the commission has included an option for businesses to submit an emission reduction plan that if approved would allow them the use of the prohibited equipment in the morning hours. Further, the commission is adopting this rule with an extended compliance schedule so that lawn and maintenance businesses may submit an emissions reduction plan or supplement their equipment with electric-powered units. The commission anticipates that affected companies will find and make the necessary adjustments to minimize economic impacts, especially considering the far more substantial impacts that would result from the failure of the HGA area to attain federal air quality standards that this rule is designed to help achieve. Although many of the rules included in the current SIP attainment strategy will not be easy to implement and will cause many of the affected entities to adjust normal operations, these rules are necessary in order to demonstrate compliance with the ozone standard. As stated previously in this preamble these rules are a necessary component of the HGA attainment strategy and will achieve the equivalent effect of reductions in NO_x of approximately 4.6 tpd.

The emission inventory maintained by the commission indicates that commercial operations are the source of the majority of weekday emissions from lawn and garden equipment. The commission cannot eliminate the operating restrictions without an established, quantifiable, and enforceable replacement strategy that demonstrates proven ozone reductions equivalent to those achieved by these rules. The commission also cannot do away with the operating restrictions because of the significant contribution that lawn and garden equipment makes to the HGA area ozone levels. Because of this significant contribution that the equipment affected by these rules make to the HGA area ozone levels, it is essential that the equipment operating restrictions rules be implemented along with the other rules and measures included in this SIP revision in order for the HGA area to demonstrate attainment with the federal ozone standard.

The proposed rule contained an analysis of information available to the commission regarding the costs and benefits of the proposed rule. The adopted rules do not require additional control equipment or new technology; therefore the commission believes that the rules are technically feasible. The commission has worked extensively with lawn and garden industry and other affected industries in the HGA area, along with consultants, to ensure that the emissions inventory and the inventory of affected equipment in the area is as accurate and as specific to the HGA area as possible. The accuracy of the inventories thereby increases the accuracy of the modeling of the affected industries' contribution to the air quality problem, as well as the necessary ozone reductions that this rule is designed to achieve.

The commission continues to believe there will not be significant economic impacts to commercial operators beyond the shift in work schedules and possible implications caused by work delays. This information met the statutory requirements of the TCAA and the APA because the information provided in the proposed rule was sufficient for commenters to submit alternative assessments of the costs and benefits.

Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn*, 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The commission received comments which were substantial in both number and in scope, regarding the costs of the proposed rule and the technical practicability of compliance. The preamble for the proposed rules contained a discussion of the FCAA requirements, including a detailed section by section discussion of the rules. Although the commission did not have specific cost data available at the time of proposal that could be included in the fiscal note, the proposal preamble did include a discussion concerning costs to state and local governments, the public benefit and the estimated costs for the affected sources, a small and micro-business analysis, a draft RIA, a TIA, and a CMP consistency determination. The commission received a number of comments that addressed multiple aspects of the adopted rules, and has revised the rules in consideration of the cost comments received. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree. Some commenters stated that the proposal did not meet the statute or that compliance with the proposed rule is not technically or economically feasible. This broad comment does not provide the commission with sufficient information to propose changes or alternative strategies. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. The commission believes the proposed rule and preamble provided enough information for commenters to rely on in order to submit specific comments. Mere disagreement with cost or technical feasibility estimates does not render notice inadequate. The commenters did not say how the notice is insufficient, merely that it is insufficient. Nevertheless, the commission has reviewed the proposed rule and preamble and has determined it is adequate because it did identify those areas where those subject to the rule could expect to incur costs.

BCCA, ExxonMobil, Phillips 66, and REI, stated that the proposed rules did not include adequate notice as required under Texas Government Code, §2002.024. The commenters stated that Texas Government Code, §2001.024, requires adequate notice of a proposed rule, including information about its public benefits and costs. The commenters stated that adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule, and that courts have considered notice "adequate" only if: interested persons can confront the agency's factual suppositions and policy preconceptions; and the agency provides interested parties the opportunity to challenge the underlying factual data relied upon by the agency. The commenters asserted that in proposing the rules, the commission failed to provide interested parties with sufficient information to constitute adequate notice.

The commenters stated that it has identified a number of critical gaps in the underlying factual data, methodology, and analysis in support of the proposed rules. The commenters asserted that the proposal included insufficient information and analysis regarding costs and impacts. The commenters asserted that the commission has not adequately responded to requests for additional information from stakeholders. The commenters stated that the following requests for information were outstanding: information regarding the modeling of emissions; information regarding the corrected emissions inventory database; and information supporting the estimated costs of control. However, available information suggests that the commission dramatically underestimated the costs of the proposed control strategies. This failure to provide the public with sufficient information renders the notice of the plan inadequate. Section 2001.024 of the APA requires the commission to provide sufficient information regarding the Plan for public review and comment before adoption. The commenters stated that this information is necessary in order to comment effectively on the proposed rules and that data gaps in the proposal hindered effective comment.

The commission disagrees with the commenters and made no change in response to these comments. Texas Government Code, §2001.024, requires of the notice of a proposed rule include certain information. Texas Government Code, 2001.024(a)(5), requires that the notice state the public benefits expected as a result of the adoption of the proposed rule and the probable economic cost to persons required to comply with the rule. Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn*, 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The proposed rule contained an analysis of information available to the commission regarding the costs and benefits of the proposed rule. The commission received comments which were substantial in both number and in scope, regarding the costs as well as the benefits and in fact, revised the proposed rule in response to comments concerning costs. As stated previously in this response to comments, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control.

The comments which state there are critical gaps did not identify what those gaps are or how that results in inadequate notice. Mere disagreement with cost estimates does not render notice inadequate.

The proposed rule meets the requirement to include sufficient information by identifying those areas where persons subject to the rule could expect to incur costs. To simply state that the proposal failed to provide sufficient information does not provide the commission with sufficient information to propose changes or alternative strategies. The commenters did not say how the notice is insufficient, merely that it is insufficient. Nevertheless, the commission has reviewed the notice and has determined it is adequate. The commission is unaware of any requests for additional information to which it was not completely responsive.

Phillips 66 stated that the commission has not provided a reasoned justification for the proposal. The commenters asserted that a rule that would impose an air emission abatement requirement that is not demonstrated to be practical and economically feasible is directly contrary to the TCAA, §382.011(b), and therefore is inconsistent with the Texas Government Code, §2001.033(a)(1)(B) and §2001.035(c).

The commission has provided a "reasoned justification" for the rules in this adoption package as required by Texas Government Code, §2001.033. The requirement for a reasoned justification applies to the agency order finally adopting a rule. The standard for compliance with the reasoned justification requirement is substantial compliance, as determined by the legislature, which amended the reasoned justification requirement in 1999. The commission has provided the factual, policy and legal bases for the rule, as required. Texas Government Code, §2001.024, requires only "a brief explanation" of the rule upon proposal in addition to other elements such as the fiscal note and public benefit evaluations. Both the rule proposal and adoption meet all of the requirements of the APA.

BCCA, ExxonMobil, Phillips 66, and REI, stated that the proposed rules did not include the local employment impact statement required under Texas Government Code, §2001.022. The commenters stated that Texas Government Code, §2001.022, requires the commission to determine whether the rule proposal has the potential to affect a local economy before proposing the rule for adoption. The commenters stated that if answered affirmatively, the commission must request that the Texas Employment Commission to prepare a local employment impact statement describing in detail the probable effect of the rule on employment in each geographic area affected by the rule for each year of the first five years that the rule will be in effect. The commenters further asserted that the commission failed to make the required initial determination and ignored the potential for the proposal to adversely affect the local economy. The commenters stated that a local employment impact statement should have been requested and prepared in advance of the proposal.

The commission agrees with the commenters that the proposed rule may affect a local economy, however, does not agree that it is the responsibility of the commission to provide the local employment impact analysis. The APA requires state agencies to determine whether a rule may affect a local economy before proposing a rule for adoption. If the agency determines that a proposed rule may affect a local economy, the agency must send a copy of the proposed rule and other information to the Texas Workforce Commission (Workforce Commission) before the agency files notice of the proposed rule with the secretary of state. The APA requires the Workforce Commission to prepare a local employment impact statement for proposed rules, if a state agency requests the statement. The commission determined that the proposed rule might affect a local economy, and sent the proposed rule and other requested information to the Workforce Commission. The commission received a letter from the Workforce Commission, indicating that the Workforce Commission did not have the ability to determine the potential local employment impacts from the proposed rule.

BCCA, ExxonMobil, Phillips 66, and REI stated that the proposed rules did not include an adequate TIA as required under Texas Government Code, §2007. The commenters stated that the TIA provision mandates that covered agencies "take a 'hard look' at the private real property implications of the actions they undertake...," according to the Office of the Attorney General, *Private Real Property Rights Preservation Act Guidelines*, (21 TexReg 387, January 12, 1996). The commenters stated that under §2007.043, a TIA must describe the specific purpose of the proposed action, determine whether engaging in the proposed governmental action will constitute a taking, and describe reasonable alternative actions that could accomplish the specified purpose. The commenters stated that the agency must also explain whether these alternative actions also would constitute takings.

The commenters stated that agencies must also comply with guidelines developed by the Texas Attorney General when developing the TIA and that according to these guidelines, agencies must carefully review governmental actions that have a significant impact on the owner's economic interest. The commenters stated that these guidelines include the statement: "Although a reduction in property value alone may not be a 'taking,' a severe reduction in property value often indicates a reduction or elimination of reasonably profitable uses." (21 TexReg 392, January 12, 1996). The commenters stated that examples of aspects of the rule proposal that could significantly impact private real property in a manner that constitutes a taking include gas-fired compressor engines and other point source NO_x controls.

The commenters stated that the commission provided the public no basis to infer that a cost/benefit analysis or a reasonableness determination was, in fact, performed as necessary to support the TIA exemption claim because the preamble contains only the bare assertions. The commenters asserted that the proposed rules will impose a greater burden than is necessary, and are not reasonably taken to fulfill a federal mandate. The commenters commented that according to the Attorney General's Guidelines, a full TIA was required to be completed with the proposal, and that failure to perform a TIA could invalidate the rules.

The primary reason the commission determined that this rule did not constitute a takings under Texas Government Code, Chapter 2007 is that it will not burden private real property. This rule applies to non-road equipment which is not real property or appurtenance thereto. The commission believes the adopted rules are exempt under §2007.003(b)(4) because they are reasonably taken to fulfill an obligation mandated by federal law. While several governmental actions are subject to being reviewed under Chapter 2007, including the adoption of rules, §2007.003(b)(4) specifically excludes an action that is reasonably taken to fulfill an obligation mandated by federal law. The rules are adopted to meet the air quality standards established under federal law as NAAQS.

The commission also believes that the adopted rules meet an additional exception to the requirements of Texas Government Code, Chapter 2007. First, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rule revisions 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 significantly advance the health and safety purpose. This action is taken in response to the HGA area exceeding the federal ambient air quality standard for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient VOC and ozone levels in HGA. Consequently, these rules meet the exemption in §2007.003(b)(13).

The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking therefore meets the requirements of Texas Government Code, §2007.003(b)(4) and (13). For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

ExxonMobil, BCCA, Phillips 66, and REI stated that the proposed rules did not include an adequate small business and micro-business assessment as required under Texas Government Code, §2006.002. BCCA also commented that none of these assessments applied the mandated cost comparison standards. The commenters stated that an analysis of the costs of compliance for small and micro-businesses must also compare the costs of compliance for these businesses with the costs for the largest businesses affected by the rule. The commenters stated that the comparison must use at least one of the following standards: cost for each employee, cost for each hour of labor, or cost for each $100 of sales. The commenters asserted that the rule proposal failed to include the mandated cost comparison standards. The commenters stated that this is the case even in those instances where the commission acknowledged a significant impact. The commenters stated that the commission either restated the costs of compliance it identified in the analysis of public benefits and costs, or concluded that it cannot determine the cost to small businesses.

The commenters asserted that the rule proposal assessments fall short of what Texas law requires and that it is not sufficient for the agency merely to state that the costs for small and large businesses will be the same. The commenters stated that the rationale behind requiring a comparison using an established standard (e.g., cost for each employee, cost for each hour of labor, or cost for each $100 of sales) is to determine whether there is a disparate impact on small businesses. The commenters stated that according to *Unified Loans v. Pettijohn*, 955 S.W.2d at 652 (Court of Appeals -- Austin, 1997), the statute's purpose is to obtain "an objective assessment of the agency's proposed action by forcing it to consider seriously. . . the effect of the rule on small businesses, including an analysis of their costs of (compliance) and a comparison of their costs with the cost of compliance for the largest businesses affected. ..." The commenters stated further that the commission cannot merely conclude that the costs to small businesses "cannot be determined," and is obliged to include in the notice "some basis" for its conclusion so that interested parties can "confront that basis in a meaningful way in their comments." (*Unified Loans v. Pettijohn*, 955 S.W.2d at 653.)

The commenters stated that in the rule proposal preamble, the commission did not publish the information mandated by Texas law and that as a result, it is impossible for the public to comment on whether the agency adequately considered the effect of the rule on small businesses, thus rendering the notice of the plan inadequate. The commenters stated that Texas Government Code, §2006.002, requires the commission to provide a comparison of the proposed rule's impact on small and large businesses, using the specified standards, for public review and comment before adoption.

TNLA commented that the proposal is excessively onerous to the landscape industry and disagreed with the commission statement that since the proposed rules did not require additional controls or new equipment, there would not be significant economic impacts to commercial operators beyond the shift in the work schedule and possible implications caused by potential work delays. TNLA noted that landscape equipment is generally replaced on a two- to four-year cycle so landscape companies can adapt to regulations requiring new technology as it becomes available with a minimal negative economic impact. The number one cost for landscape companies is labor which is increasingly unavailable. This regulation hits the industry directly where it is most vulnerable and creates the worst economic impact by not allowing any alternatives. The industry is made up of very small, family owned businesses with narrow profit margins. The business is very competitive with price being one of the top two factors in selecting a landscape firm with service being second. Manual labor cannot be substituted for the use of power equipment, for example, a test in California showed that it took five times longer to clean a typical landscape using a broom and rake than it would with a power blower. TAB commented that the labor market is already suffering from shortages and many workers might be forced to leave the industry to avoid the non-traditional work hours. Bio Energy commented that the rule will cause the loss of employees who count on the hours. RDC commented that if employers have to hire more personnel to get the same amount of work done, employers will be forced to cut wages or increase prices.

The proposal preamble acknowledged that there may be fiscal implications for small or micro- businesses as a result of the adoption and enforcement of the rules. Although the commission did not have information about number of employees, hours of labor, or amount of sales income the assessment did state that the economic impacts were not anticipated to be significant and that they were not anticipated to extend beyond any impact due to the shift in work schedules and possible implications from work delays. The commission did state that additional employees might have to be hired or additional equipment might be purchased. Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn*, 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The proposed rule contained an analysis of information available to the commission regarding the costs and benefits of the proposed rule. The commission believes that the analysis in the proposal did provide a basis for the submission of comments and the commission received a substantial number of comments related to small businesses. These included comments stating that equipment for commercial lawn and garden operations is replaced regularly on a two- to four-year cycle. For example, this would allow operators to replace a substantial portion of their current inventory with electric equipment prior to the 2005 rule implementation date. Based on this information, the commission believes that capital expenditures resulting from commercial operators' compliance with the modified rule are within the normal replacement schedule of their equipment. For example, replacement of existing inventories with electric equipment will allow commercial operators to continue their operations in the morning hours. The commission believes that replacement of equipment could allow commercial operations to continue to operate with the same number of employees after the 2005 implementation date. Further, additional comments indicate that the primary expense for these businesses is labor. The adopted rule allows commercial operators and persons to submit emission reduction plans by May 31, 2003, for approval by the executive director and the EPA no later than May 31, 2004. If an acceptable plan is submitted, commercial operators and persons will exempt from operating hour restrictions upon implementation of these rules in 2005 and therefore, and will be able to operate during the restricted hours. This would also eliminate or reduce the need for increased labor costs. The executive director may allow plans to be submitted after May 31, 2003. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division.

The commission believes that the information provided in the proposal was sufficient to provide a basis for comments on the impacts of the adopted rules on small and micro-businesses. In response to these comments, the commission has modified the proposal and is adopting a rule that will mitigate the effects on small and micro-business commercial operators.

BCCA, ExxonMobil, Lynn's, OPEI, Phillips 66, REI, TNLA, and one individual commented on the draft RIA and stated that the proposed rules were not evaluated in accordance width the analysis requirements for a major environmental rule. EWI commented that this rule does not meet the definition of a major environmental rule. The commenters stated that Texas Government Code, §2001.0225, requires an RIA for certain major environmental rules. The commenters stated that the commission must consider the benefits and costs of the proposed rule in relationship to state agencies, local governments, the public, the regulated community, and the environment. The commenters stated further that the commission must also incorporate aspects of this analysis into the fiscal note in the proposed rules (e.g., identify the costs and the benefits; describe reasonable alternative methods for achieving the purpose of the rule considered by the agency; provide the reasons for rejecting those alternatives; and identify the data and methodology used in performing the analysis). The commenters stated that under §2001.0225(d), the commission must also find that "compared to the alternative proposals considered and rejected, the rule will result in the best combination of effectiveness in obtaining the desired results and of economic costs not materially greater than the costs of any alternative regulatory method considered."

The commenters stated that the rule proposal preamble statement that the rules are exempt from the RIA requirement because federal law mandates the rules is a legally flawed effort to avoid an RIA and may render the rules invalid. The commenters stated that federal law does not mandate the control requirements, emission rates, and use restrictions contained in the proposal and asserted that many of the proposed rules exceed specific federal rules and standards applicable to the same sources. The commenters stated that examples of departures from the federal framework include the following: boiler, turbine, and other fired equipment emission limits set well below federal new source performance standards (NSPS), reasonably available control technology, best available control technology (BACT), or lowest achievable emission rate (LAER) limits for the same sources; and compressor engine emission limits set at unprecedented low levels specifically designed to be unachievable and prevent the further use of the affected engines.

TNLA commented that while the commission is required to reduce emissions, the specific action of banning use of equipment is not required. TNLA argues that an impact study of projected costs ad benefits of the regulations is necessary. OPEI notes that the draft RIA states that the specific SIP measures are not generally required by the FCAA, but instead, the FCAA provides states with flexibility to develop SIPs that will achieve air quality standards. Based on this, the commission contends that the proposed morning ban is exempt from the RIA requirements because they are required by federal law. OPEI asks if the commission has confirmed its interpretation of the RIA requirements with either the authors of SB 633 or the State Attorney General, and whether the commission's RIA interpretation is currently subject to legal challenge. OPEI also wanted to know the criteria the commission applies to distinguish major from non-major rules and the basis through which the commission has determined the proposed ban falls into the non-major category.

ExxonMobil commented that simply saying that federal law requires the rules does not make it so. ExxonMobil stated that federal law, for instance, did not mandate a 90% reduction in emissions from stationary sources of NO_x, and that the commission alone decided the blend of control requirements in the proposal. ExxonMobil stated that if the commission was exempt from conducting a major environmental analysis solely because the proposal was intended to achieve compliance with the NAAQS, an analysis would never be required for any rule relating to criteria pollutants and such an approach would render Texas Government Code, §2001.0225, superfluous. The commenters stated that the rule proposal preamble acknowledges that the rule proposal's components are "major environmental rules," but that the commission asserted that an RIA is "seldom" required and is only required for "extraordinary" rules. The commenters stated that these criteria appear nowhere in the RIA requirements. The commenters stated that the rule proposal preamble states that "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." The commenters stated that this "no greater than is necessary or appropriate" determination is the conclusion that an RIA is designed to evaluate and to offer for public review and comment. The commenters stated that the rule proposal is well beyond any federal mandates for the covered sources and are "extraordinary." The commenters stated that under Texas Government Code, §2001.0225, an RIA must be performed and offered for public comment before the proposal can be adopted.

The commission does not agree that the adopted rules meet the definition of a major environmental rule, or that the commission's interpretation of the exemption for federally mandated standards is legally flawed. The Texas Government Code, §2001.0225, only applies to a major environmental rule adopted by a state agency, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

This rulemaking action does not meet any of these four applicability requirements, and is adopted in substantial compliance with the RIA requirements. Texas Government Code, §2001.035. Further, the adopted rules are also intended to obtain NO_x and VOC emission reductions which will result in reductions in ozone formation in the HGA ozone nonattainment area under 42 USC, §7409. These rules are intended to implement an operating-use restriction program requiring that lawn and garden service equipment powered by spark-ignition engines, 25 hp or below utilized by commercial operators, or for uses not exempt under §114.452(b), are restricted from use between the hours of 6:00 a.m. and noon, April 1 through October 31. This program is part of the strategy to reduce the formation of ozone by delaying NO_x emissions from lawn and garden equipment until later in the day when optimum conditions for the formation of ozone no longer exist. The program was developed for the HGA ozone nonattainment area to be able to demonstrate attainment with the ozone NAAQS. Title 42 USC, §7410, 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 42 USC, §7410, does not specifically prescribe programs, methods, or reductions to meet the federal 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 42 USC, Chapter 85, Air Pollution Prevention and Control). The FCAA does require some specific measures for SIP purposes, such as an inspection and maintenance program, but those programs are the exception, not the rule, in the federal SIP structure. 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. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Failure to develop control strategies to demonstrate attainment can result in federal sanctions. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended, to achieve reductions in ozone precursor emissions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA.

This conclusion is supported by the legislative history for Texas Government Code, §2001.0225. During the 75th Legislative Session, SB 633 amended the Texas Government Code to require agencies to perform an RIA of certain rules. The intent of SB 633 was to require agencies to conduct an RIA of 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. 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. Because of the ongoing need to address nonattainment demonstrations required by federal law, the commission routinely proposes and adopts SIP rules. If each rule proposed for inclusion in the SIP was incorrectly considered as exceeding federal law, every SIP rule would require the full RIA contemplated by SB 633. This result would be inconsistent with the cost estimates and fiscal notes prepared by the commission and by the LBB. 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 meet the requirements under §2001.0225(a). 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. In other words, the adopted rules are intended to meet federal and state law, and do not go above and beyond what is required to meet federal or state statutes.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd, Inc.*, 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the APA by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Currently, several lawsuits have been filed that challenge rules adopted by the commission with regard to the RIA requirements. The commission, through the Texas Attorney General's office, has argued that it is not required to prepare a full RIA if the proposed rule is not a major environmental rule that exceeds any of the four applicability requirements of Texas Government Code, 2001.0225. A "major environmental rule" means a rule with the specific intent 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. When determining whether a proposed rule is a major environmental rule, the commission must consider the two prongs of the definition of "major environmental rule." First, the commission must determine the specific intent of the rule. In this case, the concept of shifting NO_x and VOC emissions to the afternoon will help reduce the formation of ozone. The HGA area exceeds the federal ambient air quality standard for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. Thus, the adopted rules will reduce risks to human health from environmental exposure. Second, the commission must determine if the proposed rules will have an adverse, material effect on the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. The commission considers the results of the fiscal analysis that is required for every proposed rule by the APA, as well as information that is generally available to the commission about an affected industry. For these rules, the commission focused on whether or not the work delay would affect a sector of the economy in an adverse material way. The commission stated in the proposal that it did not believe that businesses that provide lawn and garden services comprise a sector of the economy or that the rules would have the adverse, material affect contemplated by §2001.0225.

Further, the commission does not believe that the rules will adversely affect in a material way, the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state, particularly since the adopted rule allows commercial operators to submit emission reduction plans that, if approved, will enable them to operate during the prohibited hours. Productivity and jobs should not be adversely affected since the option to submit an emission reduction plan, coupled with the expected natural turnover of lawn and garden equipment will enable most commercial operators to continue in their normal course of business. The rule should not adversely affect public health and safety since it is intended to reduce ozone. Further, the exclusions for domestic and emergency use and the option to submit an emission reduction plan will reduce the need to perform lawn and garden services in the afternoon or early evening hours.

Therefore in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, 382.017, 382.019, and 382.039, authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

OPEI commented that Texas would receive greater SIP emission reduction credits through the mandated sale in Texas of spill-proof, portable gasoline containers. TNLA, BCCA, TLS, PPEMA, EWI, Spring Valley, Lynn's, Cornelius, Harris Landscape, Poulan, and two individuals suggested that the commission adopt California's spill-proof container. PPEMA suggested that in the event the commission falls short of the emission goals for HGA, even after accounting for the EPA's Phase II regulations, the commission should evaluate the effect of potential control measures to address spillage and refueling emissions from lawn and garden equipment. Friendly Robotics commented that they respectfully disagree with OPEI in its endorsement of a "no-spill" gasoline container rule (a rule that OPEI would like to substitute for the lawn mowing time shift rule) siting the fact that the "no-spill" containers are being offered as an alternative so as to remove focus from "the devices that actually burn the gasoline and spew out the emissions, . . ." (i.e., internal combustion engines).

The commission has not had the opportunity to extensively analyze the data submitted that supports the implementation of the California spill-proof container regulation. However, the commission does not believe that the spill-proof container rule would result in emission reductions that would have the same ozone reduction benefit as the lawn and garden rules. Even if the commission continues to review this data, the commission is unable to adopt a rule of this nature at this time and believes that it is necessary to adopt the lawn and garden shift rules.

OPEI claims that the HGAC estimates that the population in the affected eight-county non- attainment area in 2007 will be 5.14 million people, which is roughly 15% of the 33.5 million people that the CARB evaluated. Second, OPEI claims that 15% of 9.8 million gasoline containers (CARB's estimate) results in roughly 1.5 million portable gas containers in the HGA area. Third, they claim that if those 1.5 million containers were replaced with spill-proof containers in cooler California, it would result in a reduction of roughly 13 tpd in the HGA area (15% of 87 tpd CARB's container emissions contribution). Fourth, OPEI claims that the rate of evaporative emissions is very dependent on temperature and gasoline vapor pressure. OPEI assumes that the average summer temperature in Texas is around 15 degrees hotter than California, and that the EPA methodology indicates that the average rate of evaporative emissions in Texas is roughly 30% higher than the rate of evaporative emissions from containers in California (simply accounting for temperature alone assuming fuel vapor pressure is the same). OPEI asserts that according to CARB's calculations, evaporative emissions constitute roughly 75% of container emissions or roughly 9.75 tpd of projected reactive organic gas (ROG) emissions from gasoline containers in the HGA. Thus, OPEI states that the much higher summer temperatures in Texas would result in a higher evaporation rate than California resulting in an additional 2.93 tpd (30% x 9.75) of ROGs in Houston. OPEI believes that applying the CARB principles to the HGA population (with an adjustment for higher temperatures) would result in a total emission contribution from spill-proof containers in 2007 of 15.93 tons of ROGs per day (13 "California-based" tons plus 2.93 "added Texas heat" tons). OPEI assumes then that because spill- proof containers will reduce container emissions by 73%, a container rule will reduce year 2007 emissions in the HGA by 11.63 tons of ROGs (73% x 15.93).

The commission disagrees with the conclusions of OPEI. OPEI relies on population estimates that have not been confirmed by the commission. OPEI also relies on data gathered from California which cannot be applied to the HGA. For instance, OPEI estimates that 1.5 million gasoline containers are present in the HGA. However, this data is based on assumptions made by the CARB about gasoline container populations across that entire state. OPEI also assumes that California is 15 degrees cooler than Texas. This has not been verified by the commission and/or the EPA. The commission would need to determine what information this assumption was based on before making adjustments to the inventory. For instance, was this information based on mean state-wide temperatures? What is the source of the temperature data? Does this differential apply to Houston, whose summertime temperatures are moderated by the Gulf of Mexico, etc.? As for evaporative emissions constituting roughly 75% of container emissions, or roughly 9.75 tpd, the commission has received no information concerning how these figures were determined. The commission would again need to determine on what information these assumptions were based. OPEI also contends that a gas can rule would result in full compliance/turnover by 2007, since the average portable container has a useful life of five years. If the average useful lifetime of fuel containers is five years, then the commission would expect that only half of the containers could continue in use well beyond five years. A significant number of older containers could continue in use well beyond five years. OPEI contends that the commission would ultimately receive from the EPA at least comparable (if not greater) SIP emission reduction credits from a spill-proof container rule in lieu of the proposed ban. Even if it can be shown that the no-spill container rule will reduce hydrocarbon emissions in an amount equal to or greater than the amount shifted, there is no guarantee that equivalent ozone benefits would be realized. Lawn and garden emissions (which include NO_x as well as VOC) in the morning are particularly important to afternoon ozone formation, and a significant amount of morning emissions would continue to occur even with all the inventory modifications suggested in the comments, including the proposed gas can rule.

OPEI commented that there were flawed and exaggerated projected inventory contributions associated with lawn and garden engine exhaust. They suggested re-running the emission inventory model with corrected assumptions that the OPEI assumes the commission will receive from the EPA via a spill-proof container rule. OPEI believes that these inventory corrections will reduce the EPA- approved SIP credits resulting from the proposed ban to around four tpd of VOC. OPEI commented that a spill-proof container rule will improve water quality (by removing spills associated with personal water craft) and improve overall fuel efficiencies. They also commented that a spill-proof container rule would be supported (rather than challenged) by all affected industries (including Texas commercial landscape companies that would save money through not wasting fuel and container manufacturers that would sell their new products). OPEI commented that if the commission adopted a spill-proof container rule on a state-wide basis, then the entire state would receive dramatically greater SIP credits. OPEI commented that if the commission cannot implement a spill-proof container rule, then it will lose credibility with all of the other industries that were requested to develop superior alternatives.

The commission disagrees with this comment. The commission does not believe the projected inventory was flawed or exaggerated. The commission does not believe it is appropriate or accurate to adjust the HGA inventory using assumptions based on California data until that data has been demonstrated to be applicable to the HGA area and approved by the commission and EPA. The commission acknowledges that the no-spill container rule may have a number of benefits beyond the reduction of VOCs. The commission has not had the opportunity to extensively analyze the California data; however, the commission does not believe that the spill-proof container rule would result in emission reductions that would have the same ozone reduction benefit as the lawn and garden rules. The commission analyzed where emission reduction measures are most needed and where emission reduction measures will be most effective in order to demonstrate attainment. Even if the commission continues to review this data, the commission is unable to adopt a rule of this nature at this time and believes that it is necessary to adopt the lawn and garden shift rules.

OPEI commented that the commission apparently relied on the Spring 1999 EPA Non-Road Engine Model and that this model fails to recognize significant reductions in "deterioration rates" from the new EPA Phase II compliant handheld and non-handheld equipment.

The commission disagrees with this comment. The commission utilized the latest version of the NONROAD model. This means that the model did not fail to recognize significant reductions in "deterioration rates" from the new EPA Phase II compliant handheld and non-handheld equipment.

TNLA, Harris Landscape, TSDA, Lynn's, OPEI, PPEMA, RDC, Briggs & Stratton, Poulan, EETC, and three individuals commented that they believe the commission's emission reductions do not seem to take full credit for the two phases of federal emission standards for small spark-ignition engines that have already taken effect. Hence, the commenters argue that lawn equipment will be much cleaner than the commission projects. TNLA commented that the proposal fails to recognize the regulation of gasoline powered lawn and garden equipment being phased in by the EPA. According to a TNLA survey, most such equipment is replaced on a no more than four-year cycle with the majority being replaced on a two-year cycle. By 2005, the equipment on which the commission modeling is based will no longer be used by commercial firms. EPA exhaust emission regulations, Phase I, effective model year 1997, reduced emissions by 30% from unregulated levels. The Phase II regulations call for a 78% reduction from the Phase I levels. PPEMA added that the EPA Phase II rules will provide sufficient reductions for the commission to reach the targeted reductions and thus there is no need for the proposed rule. TSDA suggested giving the CARB Tier I and II standards a chance to work before implementing a ban on small engine use.

The commission disagrees with this statement. The lawn equipment modeling did take into account the various federal regulations affecting small engines which are being phased in over the next several years. The modeling also accounted for fleet turnover, i.e., the replacement of older equipment with cleaner new equipment.

Baker Botts commented that it generally supports the ongoing efforts by the commission to develop a SIP that is technologically achievable, economically reasonable, and legally approvable. Baker Botts, BCCA, ExxonMobil, Harris County Judge Robert Eckels, Phillips 66, Spring Valley, and an individual commented that the commission should incorporate into the SIP a greater level of reductions from federally preempted sources and stated that EPA-regulated sources account for about 40% of the NO_x emissions in the HGA. The commenters stated that the EPA issued a number of regulations for some federally preempted sources, such as land-based spark engines, marine, recreational and land-based diesel engines, aircraft and locomotive engines, well after the FCAA deadlines, and that the EPA recently strengthened rules for on-road and non-road vehicles and fuels, such as low sulfur gas and diesel, Tier II motor vehicles, heavy-duty highway vehicle standards, and non-road Tier II/Tier III heavy-duty engine standards. The commenters stated that delays in implementing these rules have prompted the commission to propose technically and economically infeasible emission reductions from sources in HGA that the state has authority to regulate to make up for the missing federal reductions. The commenters stated that these delays have forced the commission to propose expensive regional fuels and significant use restriction regulations. The commenters stated that the commission and the EPA can ensure an equitable distribution of the compliance burdens necessary to meet mandated air quality improvement in HGA only by allowing the SIP to capture anticipated emission reductions from federally preempted sources. Baker Botts noted that the EPA demonstrated a willingness to assume responsibility for a portion of emission reductions by creating a process in Los Angeles called a "public consultative process," that would resolve issues related to emissions from national and international sources, and that the EPA has also provided flexibility in obtaining offsets by allowing states to provide offsets to refiners based on emission reductions that the EPA projected would result from mobile sources using Tier II gasoline. Baker Botts suggested that this same sort of prospective crediting should be used to develop a more rational HGA SIP, and that the EPA should allow the commission to credit in the SIP the prospective emission reductions that will result from implementation of the Tier II gasoline rule and from other federally preempted sources. Finally, Baker Botts cited two cases wherein the District of Columbia Circuit has approved the EPA's flexibility with respect to statutory deadlines under the FCAA when the EPA has failed to meets its own deadlines, and this failure was deemed to upset the balanced federal/state responsibilities under the FCAA. ExxonMobil commented that it supports the commission and the EPA crediting the HGA SIP with an additional 60 tpd of federally preempted emission reductions that will occur over the next ten years. Harris County Judge Robert Eckels commented that the commission should work with the EPA to accelerate the implementation schedule for federally preempted emissions so that at least one-half of the related emission reductions are achieved by 2007, and that as a part of this process, the commission should delineate federal assignments detailing the engine standards and emission reductions necessary to achieve real and sustainable pollution reductions.

The commission agrees with the commenters that emission reductions from federally preempted sources would provide benefits for the HGA SIP demonstration, and the inability of the commission to regulate certain source categories has necessitated the use of other ozone control strategies. However, the commission understands that the EPA SIP approval process does not provide a mechanism for credit for emission reductions that occur after the attainment date. The commission understands that EPA is not currently considering accelerating implementation schedules for existing federal rules. The commission is working with EPA to determine the availability of SIP credit for many non-traditional control strategy mechanisms, like economic incentive programs and flexibility for preempted source categories. Additionally, the commission is working with EPA to determine an appropriate federal contribution credit available for the HGA SIP.

OPEI commented that the proposed use ban would not result in any significant environmental benefits that would justify its substantial adverse impact on the health and the jobs of thousands of landscapers and gardeners as well as the economic viability of hundreds of landscaping and gardening businesses.

The commission disagrees with this statement. The commission recognizes that compliance with this rule may cause unavoidable productivity (economic) losses in the HGA. However, the commission anticipates that commercial operators will find and make the necessary adjustments to minimize these impacts, especially considering the far more substantial impacts that would result from the failure of the HGA to attain federal air quality standards that this rule is designed to help achieve. Although many of the rules included in the current SIP attainment strategy will not be easy to implement and will cause many of the affected entities to adjust normal operations and make certain sacrifices, these rules are of critical importance in the protection of the environment and human health, which is essential for continued economic prosperity. If adopted, this rule will result in the equivalent of approximately 4.6 tpd of NO_x emissions reductions in the entire Houston/Galveston area. The commission believes this to be a significant reduction of harmful emissions in an area of the state classified as "severe " in terms of nonattainment.

OPEI commented that the commission's rule will at most shift approximately 30.6 tpd in exhaust emissions and will not impact evaporative diurnal and spillage emissions from portable gasoline containers.

Even if it can be shown that the proposed gas can rule will reduce hydrocarbon emissions in an amount equal to or greater than the amount shifted in the commission rules, there is no guarantee that equivalent ozone benefits would be realized. Small, spark-ignition engine emissions (which include NO_x as well as VOC) in the morning are particularly important to afternoon ozone formation, and a significant amount of morning emissions would continue to occur even with the gas can rule.

OPEI commented that the commission used the default non-road growth assumptions to project future activity levels in the HGA. OPEI also commented that current EPA Non-Road Model apparently applies an annual growth rate of 2.4%. However, OPEI believes that there has been relatively no growth in the population of lawn and garden equipment over the last decade, and that the commission has therefore overestimated emissions from this equipment. OPEI therefore requests that the commission apply a growth factor of 1%.

The commission estimated growth based on projections of human population, which is indeed lower than the default non-road projections. As for the use of a 1% growth rate, the commission and the EPA would require documentation of how this growth rate was derived before using it to model future emissions.

Montgomery County commented that the commission did not provide the predicted reductions of NO_x and VOC emissions.

The commission disagrees with this statement. This data was provided in the preamble of the rule package. It was stated that these rules will result 0.58 tpd NO_x shifted, 20.6 tpd VOC shifted, which will lead to a 7.7 tpd NO_x reduction equivalent. These numbers have been subsequently revised to 0.23 tpd NO_x shifted and 12.4 tpd of VOC shifted resulting in a reduction in ozone that is equal to approximately 4.6 tpd NO_x reduction.

EPA commented that for approvability the state should provide further documentation of how the benefits of this measure were calculated as this is primarily a VOC measure that has been assigned a NO_x reduction of 7.7 tpd.

This rule is intended to reduce the formation of ozone and accomplishes this by shifting VOC and NO_x emissions later into the day allowing less reaction time with sunlight. EPA is correct that the rule shifts more VOC than NO_x and could be seen as primarily a VOC measure. The commission characterization of the rules results from the fact that they results in an ozone reduction equivalent to a NO_x reduction of approximately 4.6 tpd. This figure is a modification of the original 7.7 tpd estimate that appeared in the proposal. Documentation and explanation of these calculations is provided in the SIP narrative that is concurrently adopted with this rule.

TNLA, Harris Landscape, and Lynn's commented that the data and modeling that the rule is based on are flawed because of an incomplete non-road inventory, local meteorology, use of national data not applicable to the HGA, and a lack of conclusive studies regarding ozone formation.

The commission disagrees with these comments. The commission has worked extensively with lawn and garden industry and other affected industries in the HGA area, along with consultants, to ensure that the emissions inventory and the inventory of affected equipment in the area is as accurate and as specific to the HGA area as possible. The accuracy of the inventories thereby ensures the accuracy of the modeling of the affected industries' contribution to the air quality problem, as well as the necessary ozone reductions that this rule is designed to achieve. The commission is required to use a federally-recognized and approved model for developing data that will be used to demonstrate attainment with the SIP. The commission used state-of-the-art photochemical methodologies to develop this rule. The Comprehensive Air Model with Extensions model that was used is the latest version of the photochemical model recognized by the EPA for SIP modeling. Previous inventories had been supplied by the EPA in their "Non-Road Equipment and Vehicle Emission Study" (NEVES, EPA-21A- 2001, November 1991). As such, the accepted method to model years other than the 1990 NEVES data was to apply growth factors from the Economic Growth Assessment System (EGAS). Over the last year, however, a new method of calculating non-road emissions has been developed by the EPA called the NONROAD model. The NONROAD model will be used to update the attainment modeling (1993 base case and 2007 future case) for the Houston area because the model has the best available science with regard to emission factors and treatment of activity (equipment usage rates) data. The NONROAD model works more like the highway emissions model, MOBILE, in that temperatures and fuel qualities can be modified to better reflect local conditions. The main change to the NONROAD model input stream was the use of new equipment populations for diesel construction and industrial equipment. Based on the study's findings, input files were generated for use in EPA's NONROAD emissions model in order to estimate total pollution levels from construction sources operating in the area. These results serve as an update to the commission's previous estimates based on EPA's default methodology. Even though the revised inventory has greatly reduced the uncertainty in equipment emissions, the commission continually seeks to improve its inventories.

TSDA commented that they disagree with a statement in the proposal preamble contending that small engines are the largest unregulated producer of hydrocarbons in the state under the non-road mobile source category. EPA regulations, in cooperation with CARB has already set new emission standards for January 1, 2001 that will cut hydrocarbon emissions by 59% by 2007. Briggs and Stratton has cut emissions from their products by 70% since 1990.

The commission acknowledges that these sources are subject to the EPA emission standards, however, lawn and garden equipment accounts for approximately 41 tpd of VOC. Small engines are the largest VOC emitters in the non-road category. Lawn and garden equipment accounts for 37% of the 2007 HGA eight-county area non-road VOC total, and recreational boating accounts for an additional 23% on weekdays, (on weekends their share is much higher). The other 40% is spread among many categories. The 41.2 tpd of VOCs from lawn and garden equipment account for approximately 6.5% of the total anthropogenic eight-county VOCs.

Poulan and one individual commented that this equipment (two-stroke engines) produces very little NO_x.

Generally, two-stroke engines have low compression ratios, and valve timing that leads to relatively low combustion temperatures and pressures. This means that very little nitrogen (N_2) is broken down to allow NO_x formation. This is also why two- stroke engines tend to emit much higher amounts of VOCs from unburnt fuel. These engines are a contributor to ozone formation and thus the commission believes it is appropriate to include them in the adopted rule.

Friendly Robotics commented that they would like this rule to be amended to contain a section which would encourage demonstration projects in the HGA to educate the public and the dealer/retailer community about the alternative use of robotic, electric, or battery-powered mowers in the four years before this rule is implemented.

This rule has not been changed to incorporate these requests; however, the commission supports the development of projects that will provide information about the use of alternative types of equipment. The adopted rule allows commercial operators to submit emission reduction plans that must demonstrate NO_x and VOC reductions equivalent to those required by the rules being requested for exemption, and must contain adequate enforcement provisions. It is possible that robotic, electric, or battery powered mowers could be suggested for use as part of such a plan.

STATUTORY AUTHORITY

The new sections are adopted under the TWC, §5.103, which authorizes the commission to adopt rules necessary to carry out its powers and duties under the TWC, and under the Texas Health and Safety Code, TCAA, §382.017, which provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA. The new sections are also adopted under TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.019, which authorizes the commission to adopt rules to control and reduce emissions from engines used to propel land vehicles; and §382.039, which authorizes the commission to develop and implement programs and other measures necessary to demonstrate attainment and protect the public from exposure to hazardous air contaminants from motor vehicles.

§114.452. Control Requirements.

(a) No handheld or non-handheld, lawn and garden service equipment powered by spark-ignition engines of 25 horsepower (hp) and below shall be started or operated between the hours of 6:00 a.m. and noon, during the time period from April 1 to October 31, in the counties listed in §114.459 of this title (relating to Affected Counties and Compliance Dates), except as specified in subsections (b) and (c) of this section.

(b) The following uses of lawn and garden service equipment powered by spark-ignition engines of 25 hp and below are exempt from the requirements of this division:

(1) any use at a domestic residence by the owner of, or a resident at, that domestic residence;

(2) any use by a non-commercial operator; or

(3) any use that is exclusively for emergency operations to protect human health and safety or the environment, including equipment being used in the repair of facilities, devices, systems, or infrastructure that have failed, or are in danger of failing, in order to prevent immediate harm to public health, safety, or the environment.

(c) Commercial operators or persons not exempt under subsection (b) of this section who submit an emissions reduction plan by May 31, 2003, (which is approved by the executive director and the EPA no later than May 31, 2004) are exempt from operating hour restrictions upon implementation of these rules in 2005, and are permitted to operate during the restricted hours. The executive director may allow plans to be submitted after May 31, 2003. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division. In order to be approved, the plan must demonstrate nitrogen oxide and volatile organic compound reductions equivalent to those required by the rules being requested for exemption, and must contain adequate enforcement provisions.

(d) Commercial operator is defined as any person who receives payment or compensation in exchange for operating lawn and garden service equipment powered by spark-ignition engines of 25 hp or below where the payment or compensation is required to be reported as income by the United States Internal Revenue Code. This term also includes any employees or contractors of any person as defined in the Texas Clean Air Act, §382.003(10).

§114.459. Affected Counties and Compliance Dates.

Effective April 1, 2005, persons in the following counties shall be in compliance with §114.452 of this title (relating to Control Requirements). These include Brazoria, Fort Bend, Galveston, Harris, and Montgomery Counties in the Houston/Galveston ozone nonattainment area.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009096
Margaret Hoffman
Director. Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

DIVISION 8. HOUSTON/GALVESTON HEAVY EQUIPMENT FLEETS--COMPRESSION-IGNITION ENGINES

30 TAC §§114.470, 114.472, 114.476, 114.477, 114.479

The Texas Natural Resource Conservation Commission (commission) adopts new §114.470, Definitions; §114.472, Control Requirements; §114.476, Reporting and Recordkeeping Requirements; §114.477, Exemptions; and §114.479, Affected Counties. The commission adopts these new sections in new Division 8, Houston/Galveston Heavy Equipment Fleets - Compression-Ignition Engines; Subchapter I, Non-road Engines; Chapter 114, Control of Air Pollution from Motor Vehicles, and revisions to the state implementation plan (SIP) in order to reduce ambient concentrations of ground-level ozone in the Houston/Galveston (HGA) ozone nonattainment area through the accelerated purchase of United States Environmental Protection Agency (EPA) certified Tier 2 and Tier 3 non-road equipment 50 horsepower (hp) and larger. These new sections are one element of the control strategy for the HGA Post-1999

Rate-of-Progress (ROP)/Attainment Demonstration SIP. Section 114.477 is adopted *with changes* to the proposed text as published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8230). Sections 114.470, 114.472, 114.476, and 114.479 are adopted *without changes* to the proposed text and will not be republished.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

The HGA ozone nonattainment area is classified as Severe-17 under the Federal Clean Air Act (FCAA) Amendments of 1990 (42 United States Code (USC), §§7401 et seq.), and therefore is required to attain the one-hour ozone standard of 0.12 parts per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined by Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties, has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of its Post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base-case episodes, adopted rules to achieve a 9% ROP reduction in volatile organic compounds (VOC), and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary nitrogen oxides (NO_x) waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base-case episodes which marginally exhibited model performance in accordance with EPA modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data- gathering exercise known as the COAST study. The state believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, EPA policy regarding SIP elements and timelines went through changes. Two national programs in particular resulted in changing deadlines and requirements. The first of these programs was the Ozone Transport Assessment Group (OTAG). This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in this study, and it has been concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that has impacted the SIP planning process is the revision to the national ambient air quality standard (NAAQS) for ozone. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, the EPA proposed an interim implementation plan (IIP) that it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development timelines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, that standard would continue to apply until it is attained. The FCAA requires that HGA attain the standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998 a revision to the HGA SIP which contained the following elements in response to the EPA guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by Subpart 2 of Title I of the FCAA to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the state eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs, as well as an acceleration simulation mode equivalent motor vehicle inspection and maintenance program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory state-wide programs adopted or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon Scenario VIf); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review; and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-99 ROP plan by December 31, 2000; to perform a mid- course review by May 1, 2004; and to perform modeling of mobile source emissions using the EPA mobile source emissions model (MOBILE6), to revise the on-road mobile source budget as needed, and to submit the revised budget within 24 months of the model's release. In addition, if a conformity analysis is to be performed between 12 months and 24 months after the MOBILE6 release, the state will revise the motor vehicle emissions budget (MVEB) so that the conformity analysis and the SIP MVEB are calculated on the same basis.

In order for the state to have an approvable attainment demonstration, the EPA indicated that the state must adopt those strategies modeled in the November submittal and then adopt sufficient controls to close the remaining gap in NO_x emissions. The modeling and other analysis supporting these rules and the HGA SIP indicate a gap of approximately an additional 91 tons per day (tpd) of NO_x reductions is necessary for an approvable attainment demonstration. The commission estimates that this measure will achieve a minimum of 12.2 tpd of NO_x reductions and is therefore a necessary measure to consider for closing the gap and successfully demonstrating attainment.

The emission reduction requirements included as part of this SIP revision represent substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, have worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area have formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

This rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000 and planned to be submitted to EPA by December 31, 2000.

The amount of NO_x reductions required for the area to attain the ozone NAAQS has 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 reduction strategies. The FCAA, 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 oversight committee. Commission staff have continued to improve the air quality modeling technology and refine emission inventory data. Numerous emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources, on- road and non-road mobile sources, and area sources were analyzed in multiple iterations of modeling, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling and other analysis submitted for public hearing and comment concurrently with the HGA SIP show that a significant amount of NO_x reductions practicably achievable are necessary from ozone control strategies in order for the HGA nonattainment area to achieve the ozone NAAQS by 2007, including reductions from surrounding counties included in the HGA consolidated metropolitan statistical area (CMSA).

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies. At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The current SIP revision contains rules, enforceable commitments, photochemical modeling analyses and calculation of the remaining NO_x reductions required to reach attainment (gap calculation) in support of the HGA ozone attainment demonstration. In addition, this SIP contains post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contains enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit a mid-course review.

The HGA ozone nonattainment area will need to ultimately reduce NO_x more than 750 tpd to reach attainment with the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of the accelerated purchase of federal Tier 2/Tier 3 non-road diesel equipment program will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area.

The commission adopts these amendments to Chapter 114 and revisions to the SIP in order to control ground-level ozone in the HGA ozone nonattainment area, and the adopted rules are one element of the control strategy for the HGA Post-1999 ROP/Attainment Demonstration SIP. The purpose of these adopted rules is to establish the accelerated purchase and operation of cleaner non- road, compression-ignition fleet equipment within the HGA nonattainment area which will reduce NO_x and VOC emissions that are necessary for the counties included in the HGA nonattainment area to be able to demonstrate attainment with NAAQS.

The EPA has been regulating highway (on-road) cars and trucks since the early 1970s and continues to set increasingly stringent emissions standards for such vehicles. After making considerable progress in controlling the emissions from on-road vehicles, the EPA turned its attention to non-road engines, which also contribute significantly to air pollution.

Diesel engines, also referred to as compression-ignition engines, dominate the large non-road engine market. Examples of non-road equipment that use diesel engines include: agricultural equipment such as tractors, balers, and combines; construction equipment such as backhoes, graders, and bulldozers; general industrial equipment such as concrete/industrial saws, crushing equipment, and scrubber/sweepers; lawn and garden equipment such as garden tractors, rear engine mowers, and chipper/grinders; material handling equipment such as heavy forklifts; and utility equipment such as generators, compressors, and pumps.

The EPA adopted regulations in 40 Code of Federal Regulations Part 89 (40 CFR 89), Control of Emissions from New and In-use Nonroad Engines, as effective June 17, 1994. Under 40 CFR 89, compression-ignition engines greater than 50 hp must comply with Tier 1 emissions standards that are being phased in between calendar years 1996 and 2000, depending on the size of the engine. Under the Tier 1 standards, the EPA projects that NO_x emissions from new non-road, compression-ignition equipment will be reduced by over 30% from uncontrolled levels of unregulated engines. The Tier 1 standards do not apply to engines used in underground mining equipment, locomotives, and marine vessels. The Mine Safety and Health Administration is responsible for setting requirements for underground mining equipment. Locomotives and marine vessels are covered by separate EPA programs.

On October 23, 1998, the EPA revised 40 CFR 89 and adopted more stringent emission standards for NO_x, hydrocarbons (HC, which are also called VOC), and particulate matter (PM) for new non-road, compression-ignition engines. Engines used in underground mining equipment, locomotives, and marine vessels over 50 hp are not included. This comprehensive new program phases in more stringent Tier 2 standards for all engine sizes from the model years 2001 to 2006, and yet more stringent Tier 3 standards from the model years 2006 to 2008. The following figure, which was extracted from the Table 1-1 of the "Final Regulatory Impact Analysis: Control of Emissions from Non-road Diesel Engines," (EPA 420-R-98-016, dated August 1998) shows the emission standards adopted by EPA in 40 CFR, §89.112. Also, the new program includes a voluntary program called the "Blue Sky Series" engine program to encourage the production of advanced, very low-emitting engines. Under these new standards, the EPA projects that emissions from new non-road, compression-ignition equipment will be further reduced by 60% for NO_x and 40% for PM compared to the emission levels of engines meeting the Tier 1 standards.

Figure 1: 30 TAC Chapter 114 - Preamble

As part of the attainment demonstration SIP for the Dallas/Fort Worth (DFW) ozone nonattainment area, the commission adopted accelerated non-road, compression-ignition fleet rules (§§114.410, 114.412, 114.416, 114.417, and 114.419). The adopted new rules apply requirements identical to the existing DFW rules in the eight-county HGA ozone nonattainment counties.

Non-road equipment covered by these rules only includes equipment that is used exclusively for non-road purposes because the federal Tier2/Tier 3 standards only apply to non-road engines. In other words, the rules cover non-road equipment that do not have a license plate and cannot be used on roads. Dump trucks and other equipment that are used both on-road and off-road are not subject to the requirements of these rules.

The adopted rules will require persons in the HGA nonattainment area which own or operate certain non-road equipment powered by compression-ignition engines 50 hp and up to meet the following requirements. For the portion of the fleet that is 50 hp up to 100 hp, the owner or operator must ensure that such equipment will consist of 100% Tier 2 non-road equipment by the end of the calendar year 2007. For the portion of the fleet that is 100 hp up to 750 hp, the owner or operator must ensure that such equipment consist of a minimum of 50% Tier 3 non-road equipment and the remainder Tier 2 non-road equipment by the end of the calendar year 2007. Finally, for the portion of the fleet that is greater than 750 hp, the owner or operator must ensure that such equipment consist of 100% Tier 2 engines by the end of calendar year 2007. This will accelerate the turnover rate of compression-ignition, engine-powered, non-road equipment that would occur as a result of the federal Tier 2/Tier 3 program. Alternatively, an affected person may be exempted from these requirements if an emission reduction plan is developed that will achieve emissions reductions equivalent to the full implementation of these rules. As part of this plan an owner or operator may achieve these reductions, in whole or in part, by obtaining emission reduction credits (ERC), mobile emission reduction credits (MERC), discrete emission reduction credit (DERC), or mobile discrete emission reduction credit (MDERC) in accordance with adopted new §114.477 and 30 TAC Chapter 101, General Air Rules, §101.29, Emission Credit Banking and Trading. In concurrent rulemaking (rule log number 1998-089-101-AI), the emission credit banking and trading rules are being moved to Chapter 101, Subchapter H, Emissions Banking and Trading, Division 1, Emission Credit Banking and Trading and Division 4, Discrete Emission Credit Banking and Trading.

The HGA area needs emissions reductions earlier than what the natural turnover would allow; therefore, these adopted rules will require that Tier 2 and Tier 3 equipment be purchased at an accelerated rate once they become available under the EPA schedule outlined in 40 CFR 89. The adopted rules exempt non-road engines used in locomotives, underground mining equipment, marine application, aircraft, airport ground support equipment (GSE), equipment used solely for agricultural and/or logging purposes, emergency equipment, and freezing weather equipment.

The rules will affect non-road diesel equipment 50 hp and larger such as construction, industrial, commercial, and lawn and garden equipment. Examples of equipment used in construction applications include bore/drill rigs, cement and mortar mixers, concrete/industrial saws, cranes, crawler tractors, crushing/processing equipment, dumpers/tenders, excavators, graders, off-highway tractors, off- highway trucks, pavers, paving equipment, plate compactors, rollers, rough terrain forklifts, rubber- tire dozers, rubber-tire loaders, scrapers, signal boards/light plants, skid-steer loaders, surfacing equipment, tampers/rammers, tractors/loaders/backhoes, and trenchers. Examples of equipment used in industrial applications include aerial lifts, forklifts, general industrial equipment, material handling equipment, refrigeration/air conditioning units, scrubber/sweepers, and terminal tractors. Examples of equipment used in lawn and garden applications include chippers/stump grinders, commercial turf equipment, lawn and garden tractors, and leafblowers/vacuums. Examples of equipment used in commercial applications include air compressors, gas compressors, generator sets, pressure washers, pumps, and welders.

The costs of meeting the new federal emission standards are expected to add about 1.0% to the purchase price of typical new non-road, compression-ignition equipment, although for some equipment the standards may cause price increases on the order of 2.0% to 3.0%. However, the cost of this program is the cost of having to replace the non-road, compression-ignition fleet on an accelerated schedule, not the cost of Tier 2 and Tier 3 engines. The cost of Tier 2 and Tier 3 engines is already accounted for in the EPA regulations, not as a result of these rules. The program is expected to cost between $30 million to $42 million average annual cost.

The commission solicited comment on additional flexibilities relating to rule content and implementation which have not been addressed in this or other concurrent rulemakings. These flexibilities may be available for both mobile and stationary sources. Additional flexibilities may also be achieved through innovative and/or emerging technology which may become available in the future. Additional sources of funds for incentive programs may become available to substitute for some of the measures considered here. There were 19 comments received regarding flexibilities which are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

SECTION-BY-SECTION DISCUSSION

Rules regarding an accelerated purchase of federal Tier 2 and Tier 3 non-road diesel equipment were adopted for the DFW ozone nonattainment area on April 19, 2000. These rules were adopted in Chapter 114, Subchapter I, Division 2, §114.410, Definitions; §114.412, Control Requirements; §114.416, Reporting and Recordkeeping Requirements; §114.417, Exemptions; and §114.419, Affected Counties. This rulemaking action adopts identical requirements which apply to the eight-county HGA ozone nonattainment area.

The adopted new §114.470 adds definitions for Blue Sky Series engine, compression- ignition engine, fleet, non-road engine, non-road equipment, Tier 2 engine, and Tier 3 engine.

The adopted new §114.472 requires persons in the affected counties listed in §114.479, which own or operate non-road equipment powered by compression-ignition engines to use non-road equipment powered by Tier 2 and Tier 3 compression engines. The phase-in schedule specified in these rules accelerates the natural turnover of non-road equipment. To ensure the equipment is available, the phase-in schedule specified in these rules is set up so that compliance dates come after the implementation dates of the new federal standard as specified in the federal rules in 40 CFR §89.112, as amended on October 23, 1998. For the portion of the non-road fleets powered by compression-ignition engines greater than or equal to 100 hp, but less than or equal to 750 hp, the rule requires a gradually increased percentage of Tier 2 and Tier 3 equipment required, so that by the end of calendar year 2007, at least 50% of the affected portion of the fleet shall meet Tier 3 standards and the remainder of the affected fleet shall meet Tier 2 standards. For the portion of the fleet greater than or equal to 50 hp, but less than 100 hp, the adopted rule requires that 100% of the equipment meet Tier 2 standards by the end of calendar year 2007. For engines greater than 750 hp, the adopted rule requires that 100% of the affected fleet be Tier 2 engines by the end of calendar year 2007. The rule also allows the non-road engines designated as "Blue Sky Series" engines to be counted toward the percentage requirements as either Tier 2 or Tier 3 engines. The "Blue Sky Series" engine program is a voluntary EPA program that allows for earlier introduction of cleaner engines. The emission standards for the Blue Sky Series program are the same as Tier 3 emission standards. Finally, the adopted rule will allow an EPA-certified retrofit of newly purchased engines, in order to meet the Tier 2 or Tier 3 emission standards, be allowed to meet the percentage requirements. This retrofit allowance is adopted because some newly purchased engines may be able to meet the Tier 2 and Tier 3 emission standards by being retrofitted. Therefore, for an affected entity to meet the percentage requirements, they may purchase new equipment or retrofit existing engines if there is an EPA-certified retrofit available.

The adopted new §114.476 requires persons subject to §114.472 to submit annual fleet reports. The adopted rule also requires them to maintain copies of the submitted reports for a minimum of three years.

The adopted new §114.477 exempts locomotives, underground mining equipment, marine engines, aircraft engines, airport GSE, and agricultural equipment. Locomotives, underground mining equipment, marine engines, and aircraft engines are exempt from these adopted rules because they are not regulated by the EPA non-road rule. Airport GSE is exempt from these rules because it is being regulated by another strategy being adopted concurrently. The exemption for airport GSE is intended to cover all equipment that is used to service aircraft during passenger and/or cargo loading and unloading, maintenance, and other ground-based operations. Exemptions from this equipment category which may exist in other rules or agreements, such as freezing weather equipment or leased equipment, do not apply here. Agricultural equipment is exempt from the adopted rules because of its small contribution (less than 1.0%) to non-road emissions, and because it is operated primarily in rural areas. Also, the commission adopts an exemption for equipment used exclusively for emergency operations and for equipment used exclusively for freezing weather operations due to their low impact on air quality during the ozone season. In response to comments received the commission clarified the language to make clear that logging uses are exempt.

In the rulemaking for the DFW area construction equipment operating restrictions rules, the commission specifically requested comment on allowing the use of added controls such as catalytic converters or other after-market devices, or the use of EPA-certified cleaner equipment, to exempt such equipment from the operating restrictions of these rules. In response to the DFW exemption comments and other comments to those rules concerning the difficulty in complying with these rules, the commission adopts §114.477(b). This subsection allows owners or operators to be exempt from the requirements of these rules if they submit an emissions reduction plan by May 31, 2002, that is approved by the executive director and the EPA by May 31, 2003. The executive director may allow plans to be submitted after May 31, 2002. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division. The commission anticipates that by offering this exemption, the entities affected by these rules, the trade associations representing these entities, and the manufacturers will be encouraged to accelerate the research and development of emissions-reducing technology for equipment that will enable affected entities to meet the exemption. Each plan must describe in detail how the owner or operator will modify the equipment fleet to reduce NO_x emissions by June 1, 2005 by a target amount equivalent to the total reductions achieved by implementation of these rules. If equipment subject to these rules is also subject to the HGA construction equipment operating restrictions rules, and the owner or operator would like to be exempt from both sets of rules, then the plan must reduce NO_x emissions by a target amount equivalent to the total reductions achieved by both sets of rules. If the plan demonstrates that these reductions will occur by June 1, 2005, the reductions will be considered equivalent for purposes of timing. The commission will apply emissions inventory factors for equipment used in the modeling to develop these rules to quantify the emissions reductions resulting from the fleet modifications. The commission will develop a guidance document to assist operators in developing their plans. The guidance document will contain both the target emissions amount operators must meet, as well as emission factors for each type of equipment affected by the rules, and will offer guidance on how to calculate total emissions reductions for an equipment fleet. The commission made changes to the language in this subsection (b) to clarify and make the language consistent with that in the HGA construction equipment operating restrictions rules, §114.487 of this title (relating to Exemptions).

The commission is requiring submission of the emission reduction plans by May 31, 2002 to allow sufficient time to review and quantify the collective emissions reductions the plans propose. The commission will complete the reviews by May 31, 2003, which coincides with the planned mid-course review of all control measures included in the SIP. After reviewing the plans, the commission will determine whether the collective emissions reductions adopted by the plans are equivalent to the reductions achieved from implementing both these rules.

The adopted new §114.479 specifies the counties that are subject to the new requirements. The counties included in the eight-county HGA nonattainment area are Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller.

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed the rulemaking action 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 of which the specific intent 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.

These adopted rules do not meet any of the four applicability criteria for requiring a regulatory analysis of "major environmental rule" as defined in the Texas Government Code. Section 2001.0225 applies only to a major environmental rule the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

As discussed earlier in this preamble, this rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000, and planned to be submitted to EPA by December 31, 2000.

The rules are intended to protect the environment or reduce risks to human health from environmental exposure to ozone and will 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 rules would require units of state and local government, businesses, and persons in the eight-county HGA ozone nonattainment area which own or operate non-road equipment powered by compression-ignition equipment to meet the following requirements. For the portion of the fleet that is 50 hp up to 100 hp, owners and operators must ensure that such equipment will consist of 100% Tier 2 non-road equipment by the end of the calendar year 2007. For the portion of the fleet that is 100 hp up to 750 hp, owners and operators must ensure that such equipment consist of a minimum of 50% Tier 3 non-road equipment and the remainder Tier 2 non-road equipment by the end of the calendar year 2007. Finally, for the portion of the fleet that is greater than 750 hp, owners and operators must ensure that such equipment consist of 100% Tier 2 engines by the end of calendar year 2007.

This air pollution control program is part of the strategy to reduce NO_x emissions necessary for the counties included in the HGA ozone nonattainment area to be able to demonstrate attainment with the ozone NAAQS. This is based on the analysis provided in the rule proposal preamble which was published in the August 25, 2000 issue of the *Texas Register*, including the discussion in the Public Benefit and Costs section.

These rules do not exceed an express standard set by federal law, since they implement requirements of the FCAA. Under 42 USC, §7410, states are required to adopt a SIP which provides for "implementation, maintenance, and enforcement" of the primary NAAQS in each air quality control region of the state. These rules were specifically developed as part of an overall control strategy to meet the ozone NAAQS set by the EPA under 42 USC, §7409. While 42 USC, §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 42 USC, 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 42 USC, §7410. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410 and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to achieve emission reductions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. By policy, the EPA requires photochemical grid modeling to demonstrate whether the 42 USC, §7511a(f), NO_x measures would contribute to ozone attainment. The commission has performed photochemical grid modeling which predicts that NO_x emission reductions, such as those required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The 42 USC, §7511a(f), exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under 42 USC, §7511a(f), was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

During the 75th Legislative Session, Senate Bill (SB) 633 amended the Texas Government Code to require agencies to perform a regulatory impact analysis (RIA) of certain rules. The intent of SB 633 was to require agencies to conduct an RIA of extraordinary rules. 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 previously discussed, 42 USC 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 proposes and 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. Because 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.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore, in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the Texas Clean Air Act (TCAA), §§382.011, 382.012, 382.017, 382.019, and 382.039 authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does Texas Government Code, §2001.0225.

The commission solicited public comment on the draft regulatory impact analysis and received six comments. These comments are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

TAKINGS IMPACT ASSESSMENT

The commission evaluated this rulemaking action and performed an analysis of whether the rules are subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. The specific purpose of the adopted rulemaking action would require persons in the eight-county HGA nonattainment area which own or operate non-road, compression-ignition equipment to meet the following requirements. For the portion of the fleet that is 50 hp up to 100 hp, the owner or operator must ensure that such equipment will consist of 100% Tier 2 non-road equipment by the end of the calendar year 2007. For the portion of the fleet that is 100 hp up to 750 hp, the owner or operator must ensure that such equipment consist of a minimum of 50% Tier 3 non-road equipment and the remainder Tier 2 non-road equipment by the end of the calendar year 2007. Finally, for the portion of the fleet that is greater than 750 hp, the owner or operator must ensure that such equipment consist of 100% Tier 2 engines by the end of calendar year 2007. This adopted rulemaking action will act as an air pollution control strategy to reduce NO_x emissions necessary for the eight counties included in the HGA ozone nonattainment area to be able to demonstrate attainment with the ozone NAAQS. Promulgation and enforcement of this rule will not burden private, real property. Also, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the adopted 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 partially fulfill a federal mandate under 42 USC, §7410. In addition, §2007.003(b)(4) provides that Chapter 2007 does not apply to these adopted rules since it is reasonably taken to fulfill an obligation mandated by federal law. This action is taken in response to the HGA area exceeding the NAAQS for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient NO_x and ozone levels in HGA. Attainment of the ozone standard will eventually require substantial NO_x reductions. Any NO_x reductions resulting from the current rulemaking are no greater than what the best scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard. Specifically, the emissions limitations and delays within the adopted rule were developed in order to meet the ozone NAAQS set by the EPA under 42 USC, §7409. States are primarily responsible for ensuring attainment and maintenance of the NAAQS, once the EPA has established them. Under 42 USC, §7410, and related provisions, states must submit, for EPA approval, SIPs that provide for the attainment and maintenance of NAAQS through control programs directed to sources of the pollutants involved. Therefore, the purpose of these rules is to implement a cleaner-burning, non-road, compression-ignition fleet program necessary for the HGA nonattainment area to meet the air quality standards established under federal law as NAAQS. Consequently, the exemption which applies to this rulemaking action is that of an action reasonably taken to fulfill an obligation mandated by federal law. The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. Therefore, these adopted rules will not constitute a takings under Texas Government Code, Chapter 2007.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission determined that the adopted 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 rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with the CMP. As required by 30 TAC §281.45(a)(3) and 31 TAC §505.11(b)(2), 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 reviewed this action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and determined that the action is consistent with the applicable CMP goals and policies. The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(1)). No new sources of air contaminants will be authorized and NO_x air emissions will be reduced as a result of these rules. The CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations in 40 CFR, to protect and enhance air quality in the coastal area (31 TAC §501.14(q)). This rulemaking action complies with 40 CFR 50, National Primary and Secondary Ambient Air Quality Standards, and 40 CFR 51, Requirements for Preparation, Adoption, and Submittal Of Implementation Plans. Therefore, in compliance with 31 TAC §505.22(e), this rulemaking action is consistent with CMP goals and policies.

The commission solicited comments on the consistency of the proposed rules with the CMP during the public comment period and received no comments.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000. The following entities and 40 individuals provided oral testimony and/or submitted written testimony: American Road & Transportation Builders Association (ARTBA); Associated Builders & Contractors of Greater Houston (ABC); Associated General Contractors of America, Houston Chapter (AGC-Houston); Associated General Contractors of Texas (AGC-Texas); Baker Botts; Lloyd, Gosselink, Blevins, Rochelle, Baldwin & Townsend, P.C. on behalf of BFI Waste Systems of North America, Inc. (BFI); Brazoria County Criminal District Attorney Jeri Yenne on behalf of Brazoria County Commissioners Court (Brazoria County); Brett & Wolff LLC (Brett & Wolff); British Petroleum-Amoco (BP); Business Coalition for Clean Air (BCCA); Chambers County Judge Jimmy Sylvia (Chambers County); City of Lake Jackson (Lake Jackson); City of Missouri City (Missouri City); City of Simonton (Simonton); City of Spring Valley (Spring Valley); Dow Chemical Company (Dow); Neal Gerber & Eisenberg on behalf of Engine Manufacturers Association (EMA); Environmental Defense (ED); ExxonMobil Corporation (ExxonMobil); Galveston-Houston Association for Smog Prevention (GHASP); Harris County Judge Robert Eckels (Harris County); Hispanic Community for Texas Citizens for a Solid Economy (TCSE-HC); Benthul & Kean on behalf of Houston Construction Industry Coalition (HCIC); Houston Metropolitan Planning Organization's Transportation Policy Council (Houston MPO); League of

Women Voters of the Houston area (LWV-Houston); League of Women Voters of Texas (LWV- TX); Liberty County Sheriff Gregg Arthur (Liberty County-Sheriff); RMT, Inc. on behalf of Montgomery County (Montgomery Co.); Mothers for Clean Air (MCA); National Aeronautics and Space Administration (NASA); Pamela Berger on behalf of Lee Brown, Mayor of Houston (Mayor of Houston); Phillips 66 Company (Phillips 66); Port of Houston Authority (PHA); Public Citizen; Reliant Energy, Inc. (REI); SEED Coalition (SEED); Sierra Club Houston Regional Group (Sierra-Houston); Texas City Mayor Carlos Garza (Texas City); Texas Department of Transportation (TxDOT); Texas Forestry Association (TFA); Texas Logging Council (TLC); EPA; and Waste Management (WM). The following entities and 11 individuals generally supported the proposal: BP, GHASP, Lake Jackson, LWV-Houston, LWV-TX, Missouri City, Public Citizen, and SEED. The following entities and 16 individuals generally opposed the proposal: ABC, AGC-Texas, ARTBA, Baker Botts, BCCA, BFI, Brazoria County, Chambers County, Dow, EMA, ExxonMobil, Harris County, HCIC, TCSE- HC, AGC-Houston, Liberty County-Sheriff, Montgomery Co., PHA, Phillips 66, REI, Simonton, Spring Valley, TFA, TLC, and WM. The following entities and 13 individuals suggested changes to the proposal as stated in the ANALYSIS OF TESTIMONY section of this preamble: ABC, AGC- Texas, ARTBA, BCCA, Baker Botts, BFI, Brett & Wolff, Chambers County, Mayor of Houston, Dow, ED, EMA, EPA, ExxonMobil, Harris County, HCIC, AGC-Houston, Sierra-Houston, Lake Jackson, Liberty County-Sheriff, MCA, Missouri City, Montgomery Co., NASA, PHA, Simonton, Spring Valley, Texas City, TFA, TLC, Houston MPO, TxDOT, and WM.

Phillips 66, REI, Dow, ExxonMobil, and one individual supported the comments submitted by BCCA; therefore references to BCCA should be read to include these commenters. The Mayor of Houston supported the comments submitted by Harris County; therefore references to Harris County should be read to include the Mayor of Houston. Harris County supported the comments submitted by the Houston MPO; therefore references to the Houston MPO should be read to include Harris County and the Mayor of Houston. Public Citizen supported the comments submitted by ED; therefore references to ED should be read to include Public Citizen.

ANALYSIS OF TESTIMONY

Legal Issues

AGC-Texas, ARTBA, BCCA, BFI, ExxonMobil, PHA, Phillips 66, and WM commented on the draft RIA and stated that the proposed rules were not evaluated in accordance with the analysis requirements for a major environmental rule. The commenters stated that Texas Government Code, §2001.0225, requires an RIA for certain major environmental rules. The commenters stated that the commission must consider the benefits and costs of the proposed rules in relationship to state agencies, local governments, the public, the regulated community, and the environment. The commenters stated further that the commission must also incorporate aspects of this analysis into the fiscal note in the proposed rules, e.g., identify the costs and the benefits; describe reasonable alternative methods for achieving the purpose of the rules considered by the agency; provide the reasons for rejecting those alternatives; and identify the data and methodology used in performing the analysis. The commenters stated that under §2001.0225(d) the commission must also find that "compared to the alternative proposals considered and rejected, the rule will result in the best combination of effectiveness in obtaining the desired results and of economic costs not materially greater than the costs of any alternative regulatory method considered."

The commenters stated that the rule proposal preamble statement, that the rules are exempt from the RIA requirement because federal law mandates the rules, is a legally flawed effort to avoid an RIA and may render the rules invalid. The commenters stated that federal law does not mandate the control requirements, emission rates, and use restrictions contained in the proposal and asserted that many of the proposed rules exceed specific federal rules and standards applicable to the same sources.

BFI commented that the commission failed to comply with its statutory obligations to prepare a complete and accurate fiscal note and perform a meaningful RIA. AGC-Texas and ExxonMobil commented that these rules exceed a standard set by federal law, exceeds an expressed requirement of state law, and are adopted solely under the general powers of the agency. ExxonMobil commented further that the commission must incorporate aspects of this analysis into the fiscal note and that such analysis should at least include: 1) identification of the costs and the benefits; 2) reasonable alternative methods for achieving the purpose of the rule considered; 3) reasoning for rejecting those alternatives; and 4) identification of the data and methodology used in performing the analysis. ExxonMobil commented that the commission must find that these rules will result in the ". . . best combination of effectiveness in obtaining the desired results and economic costs not materially greater than the costs of any alternative regulatory method considered." AGC-Texas expanded on this in that they state that the proposed rules will not result in the "best combination of effectiveness in obtaining the desired result and economic costs not materially greater than the costs of any alternative regulatory method considered." They commented that many of the non-road control measures being considered as alternatives are projected to cost between $3,000 and $15,000 per ton of NO_x reduced. Furthermore, ARTBA, ExxonMobil, and WM commented that they do not agree with the commission claim that these rules were exempt from these requirements because federal law "specifically required" them. WM commented that an RIA must be performed and offered for public comment before a proposal can be finally adopted.

The commenters stated that the rule proposal preamble acknowledges that the rule proposal components are "major environmental rules," but that the commission asserted that an RIA is "seldom" required and is only required for "extraordinary" rules. The commenters stated that these criteria appear nowhere in the RIA requirements. The commenters stated that the rule proposal preamble states that "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." The commenters stated that this "no greater than is necessary or appropriate" determination is the conclusion that an RIA is designed to evaluate and to offer for public review and comment. The commenters stated that the rule proposal is well beyond any federal mandates for the covered sources and are "extraordinary."

The commission agrees that these rules meet the definition of a major environmental rule; however, the commission disagrees that its interpretation of the exemption for federally mandated standards is legally flawed. While the rules may require significant capital investment by equipment owners and operators, that alone is not enough to trigger the RIA requirements. The Texas

Government Code, §2001.0225, only applies to a major environmental rule adopted by a state agency, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

This rulemaking action does not meet any of these four applicability requirements, and is adopted in substantial compliance with the RIA requirements in Texas Government Code, §2001.035. These rules do not exceed an express standard set by federal law, because the fleet requirements are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. Title 42 USC, §7410 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 42 USC, §7410 does not specifically prescribe programs, methods, or reductions to meet the federal 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 42 USC, Chapter 85, Air Pollution Prevention and Control). Title 42 USC does require some specific measures for SIP purposes, such as an inspection and maintenance program, but those programs are the exception, not the rule, in the federal SIP structure. The provisions of 42 USC 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. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Failure to develop control strategies to demonstrate attainment can result in federal sanctions. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by 42 USC. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with 42 USC. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to achieve reductions in ozone precursor emissions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by 42 USC.

This conclusion is supported by the legislative history for Texas Government Code, 2001.0225. During the 75th Legislative Session, SB 633 amended the Texas Government Code to require agencies to perform a RIA of certain rules. The intent of SB 633 was to require agencies to conduct an RIA of 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. 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. Because of the ongoing need to address nonattainment demonstrations required by federal law, the commission routinely proposes and adopts SIP rules. If each rule proposed for inclusion in the SIP was incorrectly considered as exceeding federal law, every SIP rule would require the full RIA contemplated by SB 633. This result would be inconsistent with the cost estimates and fiscal notes prepared by the commission and by the LBB. Because 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 meet the requirements under §2001.0225(a). While the SIP rules will have a broad impact, that impact is no greater than is necessary or appropriate to meet the requirements of 42 USC. In other words, the proposed rules are intended to meet federal and state law, and do not go above and beyond what is required to meet federal or state statutes.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the APA by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." under Texas Government Code, §2001.035. The legislature specifically identified §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, 382.017, 382.019, and 382.039 authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct an RIA as provided in Texas Government Code, §2001.0225.

BCCA, BFI, ExxonMobil, Phillips 66, and WM commented that the rules were proposed without an adequate takings impact assessment (TIA). BFI commented that the agency failed to perform a meaningful TIA. BCCA, ExxonMobil, and WM stated that Chapter 2007 of the Texas Government Code requires an agency to prepare a written TIA when proposing a rule. BCCA, ExxonMobil, and WM further stated that the assessment must describe the purpose of the proposed action; determine whether engaging in the proposed action will constitute a taking; and describe reasonable alternative actions that could accomplish the specified purpose and explain whether these alternatives actions also would constitute a takings. BCCA commented that these rules will significantly impact private real property by rendering existing non-road equipment unusable. BCCA and ExxonMobil stated that guidelines from the attorney general direct an agency to carefully review governmental actions that have a significant impact on the owner's economic interest. Finally, BCCA commented that commission did not explain why the rules were reasonably taken to meet the federal requirement and therefore does not qualify for the exemption claimed. BCCA stated that these rules require more than is necessary to meet the federal requirement.

The primary reason the commission determined that these rules did not constitute a takings under Texas Government Code, Chapter 2007 is that they will not burden private real property. These rules apply to non-road equipment which is not real property nor an appurtenance thereto.

In its analysis, the commission also found that the rules are exempt from Texas Government Code, Chapter 2007 under §2007.003(b)(4), because they are reasonably taken to fulfill an obligation mandated by federal law. The commission included elsewhere in this preamble its reasoned justification for adopting this strategy and explained why it is a necessary component of the federally mandated SIP. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary, and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking action therefore meets the requirements of §2007.003(b)(4). Although the rule amendments 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 significantly advance the health and safety purpose and therefore meet the requirement of §2007.003(b)(13). For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

BCCA, ExxonMobil, PHA, Phillips 66, and WM stated that the proposed rules did not include adequate notice as required under Texas Government Code, §2002.024. ExxonMobil commented that §2002.024 requires that the notice of a proposed rule include: a brief explanation of the proposed rule; its text; a statement of the statutory or other authority for the proposed rule; a fiscal note showing its impact to state and local governments; a note about public benefits and costs; the local employment impact statement (if required); a request for comments from any interested person; and other statements required by law. BCCA, ExxonMobil, PHA, and WM stated that adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule, and that courts have considered notice "adequate" only if: 1) interested persons can confront the agency's factual suppositions and policy preconceptions; and 2) the agency provides interested parties the opportunity to challenge the underlying factual data relied upon by the agency. BCCA, PHA, and WM commented that §2001.024 of the APA requires adequate notice of a proposed rule, including information about its public benefits and costs.

BCCA, Phillips 66, and WM stated that they have identified a number of critical gaps in the underlying factual data, methodology, and analysis in support of the proposed rules. The commenters asserted that the proposal included insufficient information and analysis regarding costs and impacts. The commenters asserted that the commission has not adequately responded to requests for additional information from stakeholders. The commenters stated that the following requests for information were outstanding: information regarding the modeling of emissions, information regarding the corrected emissions inventory database, and information supporting the estimated costs of control. The commenters stated that this information is necessary in order to comment effectively on the proposed rules and that data gaps in the proposal hindered effective comment.

The commission disagrees with the commenters and made no change in response to these comments. Texas Government Code, §2001.024 requires that the notice of a proposed rule to include certain information. Subsection (a)(5) requires that the notice state the public benefits expected as a result of the adoption of a proposed rule and the probable economic cost to persons required to comply with the rule. Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn*, 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of these rules. The commission received intelligent comments which were substantial in both number and in scope, regarding the costs as well as the benefits. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the notice must include the cost of a reasonable method of compliance. Mere disagreement with cost estimates does not render notice inadequate.

These rules meet the requirement to include sufficient information in explaining the fleet requirements, to whom they apply, the compliance schedule, the anticipated cost of compliance, and the anticipated reduction in emissions. To simply state that the proposal failed to provide sufficient information does not provide the commission with sufficient information to propose changes or alternative strategies. The commenters did not say how the notice is insufficient, merely that it is insufficient. Nevertheless, the commission reviewed the notice, determined it to be adequate, and responded to comments regarding costs associated with compliance with these rules elsewhere in this ANALYSIS OF TESTIMONY.

Similarly, the comments which state there are critical gaps did not identify what those gaps are or how that results in inadequate notice. The commission is unaware of any requests for additional information to which it was not completely responsive.

BCCA, ExxonMobil, PHA, Phillips 66, and WM commented that the rules were proposed without an adequate small and micro-business assessment. Specifically, the commenters stated that the commission failed to consider the costs of compliance for small and micro-businesses, and that the proposal did not adequately compare of the cost of compliance for small businesses to the cost of compliance for the largest businesses affected by the proposed rules. The commenters stated that Texas Government Code, §2006.002, requires an agency to prepare a statement in the rule proposal of the effect on small and micro-businesses. The commenters further stated that this statement must include an analysis of the cost of compliance with the rules, and a comparison of the cost of compliance for small and micro-businesses with the cost of compliance for the largest business effected by the rules. The commenters stated that this comparison must use one of the following standards: cost for each employee, cost for each hour of labor, or cost for each $100 of sales. BCCA noted that none of the SIP rules' small and micro-business assessments applied the mandated cost comparison standards, even where the commission acknowledged "significant" impact. BCCA commented that the commission either restated the costs of compliance it identified in the analyses of public benefits and costs, or concluded that it cannot determine the cost to small businesses. BCCA noted that it is impossible for the public to provide comment on whether the commission adequately considered the effect of the rules on small business because the commission did not publish the information required by Texas law. Finally, ExxonMobil commented that an agency must provide a basis for its conclusion that a rule does not adversely impact small business and compare the impact on large versus small business.

The commission estimated, to the extent possible, the costs to small businesses and determined that the cost depends more upon the number of non-road engines operated by the business, and that it is not dependent upon the number of employees, hours of labor, or amount of sales income. Some small businesses have only one piece of non-road equipment while others have large fleets. Large businesses vary in the same way. The size of the fleet is not dependent upon the size of the business. The commission provided the estimated cost per piece of equipment and argues that this is the only meaningful way to provide sufficient notice of the cost to small business, and therefore, that it meets the objective of the Texas Government Code, Chapter 2006. This assertion is supported by the fact that no small businesses provided comments which include cost of compliance in terms of the number of employees, hours of labor, or amount of sales income.

BCCA, ExxonMobil, PHA and WM commented that the rules did not include the local employment impact statement required under Texas Government Code, §2001.022. The commenters stated that §2001.022, requires the commission to determine whether the rule proposal has the potential to affect a local economy before proposing the rule for adoption. The commenters stated that if answered affirmatively, the commission must request that the Texas Workforce Commission (Workforce Commission) to prepare a local employment impact statement describing in detail the probable effect of the rules on employment in each geographic area affected by the rule for each year of the first five years that the rules will be in effect. The commenters further asserted that the commission failed to make the required initial determination and ignored the potential for the proposal to adversely affect the local economy. The commenters stated that a local employment impact statement should have been requested and prepared in advance of the proposal.

The commission agrees with the commenters that the rules may affect a local economy, however, does not agree that it is the responsibility of the commission to provide the local employment impact analysis. The APA requires state agencies to determine whether a rule may affect a local economy before proposing a rule for adoption. If an agency determines that a proposed rule may affect a local economy, the agency must send a copy of the proposed rule and other information to the Workforce Commission before the agency files notice of the proposed rule with the secretary of state. The APA requires the Workforce Commission to prepare a local employment impact statement for proposed rules, if a state agency requests the statement. The commission determined that the proposed rules might affect a local economy, and sent the proposed rules and other requested information to the Workforce Commission. This commission received a letter from the Workforce Commission, indicating that they did not have the ability to determine the potential local employment impacts from the proposed rules.

AGC-Texas, ARTBA, BCCA, BFI, EMA, PHA, Simonton, Spring Valley, WM, and two individuals commented on federal preemption. One individual commented that the rules may be preempted by federal regulations. Another individual and Spring Valley commented that any attempt by the commission to adopt a rule governing the emissions of non-road diesel engines is preempted by federal law. ARTBA, BCCA, BFI, and PHA commented that the FCAA, §209 preempts the commission from adopting these rules. BFI further stated that the Supremacy Clause of the United States Constitution preempts the commission from adopting these rules. AGC-Texas and BCCA commented that §209(e)(1) preempts states from regulating new non-road engines in construction equipment/vehicles and farm equipment/vehicles smaller than 175 hp. AGC-Texas and WM commented that the rule language in 30 TAC §114.472 expressly requires fleets to meet engine "standards" and that these standards exceed federal standards because federal standards do not apply to used engines. AGC-Texas and WM further commented that §209(e)(2) authorizes California to adopt and enforce "standards and other requirements relating to the control of emissions," but other states are not allowed to adopt new or used engine standards. Finally, AGC-Texas commented that states must adopt California's non-road standards if they wish to control new or used non-road engines not preempted by §209(e)(1), and at this time California has not adopted used non-road engine standards. EMA commented that §209(e)(2) broadly preempts all states and their political subdivisions (except California) from adopting or attempting to enforce "any standard or other requirements relating to the control of emissions" from non-road engines and vehicles (42 USC, §7543(e)). EMA further commented that preemption applies to all non-road engines and vehicles, whether they are "new" or not. They further stated that the rules would effectively ban the sale and operation if Tier 1 non-road engines and vehicles that are otherwise authorized for sale and operation under controlling federal law, and that this would constitute a standard or other requirement relating to the control of emissions from non-road engines. Simonton commented that the commission should have no authority to tell owners of diesel equipment when to retire equipment.

The commission disagrees that these rules are preempted by federal law. The mobile source provisions of 42 USC were written to protect manufacturers against a patchwork of different state standards. See *Engine Manufacturers Association v. EPA*, 88 F.3d 1075, 1079 (D.C. Cir. 1996). In accordance with the court's interpretation, only standards which apply to the non-road vehicles or engines are preempted by the FCAA, §209(e). States retain authority to promulgate in-use restrictions. Under this rule, no manufacturer will have to create a special vehicle for Texas which is what Congress intended to prohibit. The EPA established the existing standards for non-road engines. These rules do not set a standard for non-road engines, but instead they require that certain percentages of a non-road fleet meet the existing federal Tier 2 and Tier 3 standards. Additionally, these rules do not set a standard for in-use engines, they simply restrict the use of older, dirtier engines within the HGA nonattainment area. This type of use restriction is clearly allowed by the EPA rule for state implementation and case law regarding preemption under §209(e). See 59 Fed. Reg. 36, 969 (July 20, 1994) and *Engine Manufacturers Association v. E.P.A.*, 88 F.3d 1075 (D.C. Cir. 1996). The commission disagrees with the comment which characterizes these rules as a standard instead of a use restriction. The rules do not attempt to regulate or "ban" the sale of Tier 1 equipment. The rules place no restrictions on the sale of equipment, only the area of use. Tier 1 equipment may be used outside the nonattainment area or it may be used in the area if the operator choose to comply with an alternative plan for emissions reduction. In fact, the reductions required by these rules do not have to be created by the equipment owner or operator but may be acquired from other entities, by the purchase of credits through the cap and trade program established in a concurrent rulemaking action. For these reasons, these rules are not preempted by federal law.

An individual, AGC-Texas, and HCIC commented on legal authority. The individual stated that the commission broadly interpreted the TCAA to give them the authority to regulate non-road diesel engines. The individual further stated that the commission authority is limited to on-road vehicles, and that it is not reasonable to believe or infer that the Texas Legislature intended to directly confront the FCAA and to usurp the EPA's direct responsibilities. AGC-Texas commented that proposal of these rules exceed the commission's statutory authority. AGC-Texas commented that TCAA, §382.09, applies "to engines used to propel land vehicles" and that this section does not apply to "equipment" or engines used not only to propel, but also to perform other functions. AGC-Texas commented further that the prime function of the equipment covered by these rules is not that of a land vehicle, and that this point is further reinforced by the definition a motor vehicle in Texas Transportation Code, §114.500(2). AGC-Texas concluded that these rules are therefore based solely on the general powers of the agency. HCIC questioned the legal ability of the agency to write and implement these rules.

The commission assumes that AGC-Texas is referring to TCAA, §382.019 as opposed to 382.09. In addition to §382.019, the commission also cites authority in §§382.011, 382.012, 382.017, and 382.039, all of which provide specific authority for this rulemaking, and are not "general powers" of the agency. Section 382.019 specifically authorizes rules to reduce emissions from engines used to propel land vehicles. As noted by AGC-Texas, engines subject to this rule are used, at least in part, to propel the equipment. The statute doesn't limit the commission's authority to engines which are used solely or primarily to propel engines. Therefore the commission asserts that §382.019 does provide authority for the adoption of these rules. Additionally, the presence of this authorization does not imply a lack of authority to control emissions from other types of vehicles or equipment. For these reasons, the commission disagrees that this rulemaking exceeds its statutory authority.

ABC commented that it is their understanding that Texas Health and Safety Code, §392.011(b) directs the commission to seek to implement the TCAA through measures that are "practicable and economically feasible." ABC stated that these rules are anything but economical and feasible. BFI commented the rules violate the TCAA in that the commission failed to conduct an analysis sufficient to determine the economic feasibility of the rules and the public health and general welfare impacts of those rules as required by TCAA, §§382.011 & 382.002. AGC-Texas commented that this strategy is not economically feasible.

These rules as proposed anticipated the possibility that some regulated entities may find it difficult to replace their diesel equipment in accordance with the schedule in the rules. Therefore the rules include a provision which would allow the owner or operator to propose an alternative strategy to achieve equivalent reductions. If there is a more cost-effective way to achieve the necessary reductions, these rules allow for it to be implemented instead of the fleet requirements. This provision of the rules ensures that the requirements are practical and economically feasible. In the event that no other alternative is more cost effective, then compliance with the fleet requirements is the most practical and economically feasible way to make the reductions necessary to meet the federal air quality standards.

Cost of compliance and equipment availability

ABC, AGC-Texas, ARTBA, BFI, Chambers County, Harris County, HCIC, Texas City, Spring Valley, Missouri City, and six individuals commented on the financial impact of these rules. One individual commented that the cost of new equipment must be borne by the public in the case of equipment used by industry and the taxpayer in the case of government work and equipment. Another individual commented that these rules will economically devastate small and marginal construction companies. The third individual commented that the people should not be forced to do things, plus people cannot afford it. The fourth individual commented that the rules would greatly add to the city operating and capital costs. The fifth individual commented that these rules will bankrupt businesses. The sixth individual commented that the rules will cause small business owners to find a way to get around the rules by being dishonest, or if he does follows the rules, then he will be forced out of business by the cost of replacing equipment. Chambers County questioned if the rules are going to shut their construction and economic development down. HCIC and Harris County commented that they oppose the rules for economic reasons. ARTBA commented that small businesses, minority-owned construction companies, and minority and low-income workers will be impacted by these rules. ARTBA further stated that the rules will impose huge capital costs on construction companies. AGC- Texas commented that contractors will have to borrow $4.5 billion in order to comply with these rules and that this amount of debt can not be absorbed by the industry. ABC commented that contractors will be seriously damaged economically if they are forced to purchase new equipment before the lifespan of their equipment has been reached. They further commented that cost of these rules to the construction industry, along with the workday shift rules, would be around $450 million for the eight- county area. Texas City commented that the rules will result in an increase of equipment cost which will make it harder for smaller communities and school districts to comply with the rules. Missouri City commented that increased costs with city construction projects could result.

The commission recognizes that compliance with these rules will result in increased costs and economic impacts to affected businesses and the communities in which these businesses operate. However, the commission anticipates that affected companies and communities will find and make the necessary adjustments to minimize these impacts, especially considering the far more substantial economic impacts that would result from the failure of the HGA area to attain the federal air quality standards that these rules are designed to help achieve. These rules are an essential component to the overall strategy to reduce peak ozone levels to enable the HGA area to attain federal ozone standards. Although many of the rules included in the current SIP attainment strategy will not be easy to implement and will cause many of the affected entities to adjust normal operations and make certain sacrifices, these rules are of critical importance in the protection of the environment and human health, which is essential for continued economic prosperity for all entities affected by the rules. The failure to attain these standards would significantly impact the area's economy, and the quality of life of its citizens and communities.

In order to provide maximum flexibility, the rules includes a provision for an emissions reduction plan. This is a plan submitted to the commission by a fleet owner or operator to show alternate methods of achieving emissions reductions equivalent to the emissions reductions that would be achieved by complying with the requirements of these rules. This provision will allow for the financial impacts to industry and governments to be mitigated if they find ways to achieve the emission reductions without having to buy new equipment.

ABC, BCCA, and Dow commented on federal Tier 2/Tier 3 equipment availability. ABC and BCCA commented that the commission is requiring owners and operators to have Tier 2 and Tier 3 engines and equipment earlier than the federal schedule. ABC commented that the accelerated implementation of the Tier 2 and Tier 3 engines may not be possible given that many of the nation's engine manufacturers are only planning their rollout of Tier 2 and Tier 3 engines based on the FCAA schedule. BCCA commented that the rules impose a duty on owners and operators to have in place, engines that meet Tier 2/3 standards on a schedule that is earlier than the federal standard. Dow commented that they can not determine if Tier 2 or Tier 3 equipment is available or if it will become available by the effective date of these rules.

These rules do not accelerate the implementation of the Tier 2 and Tier 3 engines as set forth in 40 CFR, §89.112. The rules simply require that a fleet owner or operator ensure that their fleet consists of Tier 2 and Tier 3 engines as specified in §114.472. In essence, these rules accelerate the natural turnover of the equipment. All manufacturers who plan to keep selling non-road diesel engines in the United States will already have to comply with the Tier 2 and Tier 3 standards. At this time, the commission is unaware of any manufacturers that are not going to sell Tier 2 and Tier 3 engines. Furthermore, the requirement dates in the rules were determined so that they come after the federal implementation dates of the Tier 2 and Tier 3 engines. In other words, if a owner or operator of a fleet chooses to buy new non-road equipment to comply with these rules, then this equipment will already be on the marketplace. The following table contains the implementation dates of the federal Tier 2 and Tier 3 standards.

Figure 2: 30 TAC Chapter 114 - Preamble

For example, the rules as adopted require non-road equipment fleets in the 100 to 750 hp range to be 10% Tier 2 by the end of 2004. Tier 2 engines are available beginning in years 2001 to 2003 for this hp range. Thus the rules are not requiring use of the equipment until it is available on the marketplace.

An individual, NASA, PHA, and WM commented on the compliance schedule. The individual asked that more time be given in the compliance schedule. NASA, PHA, and WM commented that they are concerned that the transition to lower emission diesel engines may not be achievable due to production limitations of the original equipment manufacturers (OEM), and NASA encouraged the commission to work with the OEMs to ensure a realistic schedule. Furthermore, PHA suggestd that, if the commission does pursue this rule, then in order to address the engine availability issue, PHA requested that an exemption be added to §114.477 as follows: *(c) An operator is exempt from complying with §114.472 and §114.476, if it can demonstrate that no equipment that can perform the function of the equipment to be replaced and that meets the Tier 2 and Tier 3 standards is commercially available.*

The commission disagrees that an exemption as outlined by PHA should be added to the rules. Furthermore the commission believes that the compliance schedule is long enough to ensure adequate supply. The commission expects that the adoption of these rules and the subsequent demand that will result from the adoption will prompt the manufacturers to make sure that they can meet the demand. Also, if fleet operators or owners submit emissions reduction plans, that are approved by the commission, then the demand for the equipment may not be as great since there will be other alternatives to achieve the emissions reductions.

MCA commented that rules such as the construction ban will not be effective. MCA stated that accelerating the phase-in schedule of these rules would provide the additional NO_x reductions that would purportedly be gained from the construction ban.

The commission believes that the "construction ban" will be effective rules. Furthermore, it is not possible to accelerate the phase-in schedule any more than what is already in the rules because the requirement dates in the rules were established so that they come after the federal implementation dates of the Tier 2 and Tier 3 engines. In other words, if a fleet owner or operator chooses to buy new non- road equipment to comply with the rules, then this equipment will already be on the marketplace. The commission believes that the compliance schedule is as aggressive as possible given these considerations.

An individual commented that the commission should require California heavy equipment engines on new equipment as of October 1, 2003.

The commission disagrees with this comment. California has adopted the federal Tier 2 and Tier 3 standard for non-road engines. Therefore requiring California engines would achieve the same benefit as requiring a federal engine. Furthermore, the commission disagrees with using October 1, 2003 as a start date because Tier 2 engines with hp greater than or equal to 50 and less than 100 and engines with hp greater than 750 will not be on the market yet. No changes have been made to the rule in response to this comment.

An individual commented that the rules go far beyond anything that is necessary to protect the environment, that the analysis and basis behind these rules is flawed, and that these rules are being set up to embarrass Texas and the Governor.

The commission's intent is not to embarrass Texas and/or the Governor but instead to comply with the timelines provided in 42 USC and subsequent EPA guidance for submitting rules to demonstrate ozone attainment in HGA. Accordingly, the commission has committed to adopting the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000.

The commission worked extensively with the construction industry and other affected industries in the HGA area, along with consultants, to ensure that the emissions inventory and the inventory of affected equipment in the area is as accurate and as specific to the HGA area as possible. The accuracy of the inventories thereby ensures the accuracy of the modeling of the affected industries' contribution to the air quality problem, as well as the necessary ozone reductions that these rules are designed to achieve. The commission is required to use a federally-recognized and approved model for developing data that will be used to demonstrate attainment with the SIP. The commission used the most state-of-the-art photochemical methodologies to develop these rules. The Comprehensive Air Model with Extensions (CAMx) model that was used is the latest version of the photochemical model for SIP modeling recognized by the EPA. The Houston Diesel Construction Emissions project was conducted with the goal of improving upon the emission levels used previously in the Houston attainment plan. Previous inventories had been supplied by the EPA in their Non-Road Equipment and Vehicle Emission Study (NEVES). As such, the accepted method to model years other than the 1990 NEVES data was to apply growth factors from the Economic Growth Assessment System (EGAS); then technology reduction factors had to be applied to the grown inventories to model new federal emission rules such as those for diesel engines. Over the last year, however, a new method of calculating non-road emissions has been developed by the EPA called the NONROAD model. The NONROAD model will be used for updating the attainment modeling (1993 base case and 2007 future case) for the Houston area because the model has the best available science with regard to emission factors and treatment of activity (equipment usage rates) data. The NONROAD model works more like the highway emissions model, MOBILE, in that temperatures and fuel qualities can be modified to better reflect local conditions. The main change to the NONROAD model input stream was the use of new equipment populations for diesel construction equipment. The commission worked with representative construction operators through independent engineering firms. The general approach was to define the market share of the representative construction companies and then upscale the equipment totals based upon estimated total market share. Local equipment data then had to be adjusted to state equipment populations using adjustment factors, because NONROAD requires state-wide totals to perform the county-based calculations. Under contract with the Houston-Galveston Area Council (HGAC), Eastern Research Group (ERG) conducted a detailed survey of construction equipment populations and activity within the eight-county HGA ozone nonattainment area. As part of this effort, Starcrest Consulting facilitated communications with a coalition of local construction trade organizations and assisted with the development of survey strategies. Based on the study's findings, input files were generated for use in the EPA NONROAD emissions model in order to estimate total pollution levels from construction sources operating in the area. These results serve as an update to the commission's previous estimates based on the EPA's default methodology. Commission staff then re-ran the NONROAD model using the revised input files to develop a revised construction emissions inventory for the Houston area. For several reasons it is believed that the NEVES survey methodology originally used significantly overestimated equipment populations (and therefore emissions) for the construction sector in Houston. For example, Houston serves as headquarters for some of the world's largest construction companies, with thousands of employees dedicated to engineering and administrative work. However, the employment surrogates found in the County Business Patterns Report do not distinguish between "office" and "field" employees. While the number of construction field employees in a given area may be indicative of overall construction activity, projections using total "construction employment" in the Houston area may drastically overestimate overall equipment numbers and activity. For these reasons it was thought that a "bottom-up" survey of construction sources in the area could provide significant improvements to the equipment inventory. However, previous survey attempts encountered very low response rates, and ultimately proved unsuccessful. As part of a multi-task contract with HGAC, ERG agreed to perform a comprehensive survey of all construction equipment activity in the eight-county HGA ozone nonattainment area. In order to improve survey response rates, ERG obtained assistance from a coalition of several local trade organizations, termed the HCIC. The HCIC, along with their representative Starcrest Consulting, was instrumental in identifying key experts for interviews, as well as encouraging their member companies to actively participate in the survey effort. This effort provided the commission with a much-improved inventory of construction equipment emissions in the Houston area, and resulted in the revisions incorporated into the Base 6 and Base 6a modeling. Even though the revised inventory greatly reduced the uncertainty in construction equipment emissions, the commission continually seeks to improve its inventories.

Based upon this in-depth work, the commission believes that the analysis and basis behind the rules is not flawed. Additionally, the SIP modeling makes clear that the SIP does not require more reductions than are absolutely necessary.

Alternatives and Flexibilities

Two individuals, Baker Botts, AGC-Texas, BCCA, Dow, and Spring Valley commented on the need for the EPA to implement the Tier 2 and Tier 3 standards sooner that what is currently prescribed, and to be held accountable for their lack of timely action on non-road engines. One individual and Spring Valley commented that the commission should engage in discussion with the EPA to encourage the earlier implementation of these standards. The second individual, Baker Botts, and PHA commented that the commission should urge the EPA to grant SIP consideration based on their lack of timely action. AGC of Texas commented that the EPA should accept responsibility for the late promulgation of federal standards for non-road engines. They commented that this has caused the commission to consider onerous strategies with regard to these engines that are not economically feasible. Baker Botts commented that it generally supports the ongoing efforts by the commission to develop a SIP that is technologically achievable, economically reasonable, and legally approvable. Baker Botts, BCCA, ExxonMobil, Harris County, Phillips 66, Spring Valley, and an individual commented that the commission should incorporate into the SIP a greater level of reductions from federally preempted sources and stated that EPA-regulated sources account for about 40% of the NO_x emissions in the HGA. The commenters stated that the EPA issued a number of regulations for some federally preempted sources, such as land-based spark engines, marine, recreational and land-based diesel engines, aircraft, and locomotive engines, well after the FCAA deadlines, and that the EPA recently strengthened rules for on-road and non-road vehicles and fuels, such as low sulfur gas and diesel, Tier 2 motor vehicles, heavy-duty highway vehicle standards, and non-road Tier 2/Tier 3 heavy-duty engine standards. The commenters stated that delays in implementing these rules have prompted the commission to propose technically and economically infeasible emission reductions from sources in HGA that the state has authority to regulate to make up for the missing federal reductions. The commenters stated that these delays have forced the commission to propose expensive regional fuels and significant use restriction regulations. The commenters stated that the commission and the EPA can ensure an equitable distribution of the compliance burdens necessary to meet mandated air quality improvement in HGA only by allowing the SIP to capture anticipated emission reductions from federally preempted sources. Baker Botts noted that the EPA demonstrated a willingness to assume responsibility for a portion of emission reductions by creating a process in Los Angeles called a "public consultative process," that would resolve issues related to emissions from national and international sources, and that the EPA has also provided flexibility in obtaining offsets by allowing states to provide offsets to refiners based on emission reductions that the EPA projected would result from mobile sources using Tier 2 gasoline. Baker Botts suggested that this same sort of prospective crediting should be used to develop a more rational HGA SIP, and that the EPA should allow the commission to credit in the SIP the prospective emission reductions that will result from implementation of the Tier 2 gasoline rule and from other federally preempted sources. Finally, Baker Botts cited two cases in which the District of Columbia Circuit Court has approved the EPA's flexibility with respect to statutory deadlines under the FCAA when the EPA has failed to meets its own deadlines, and this failure was deemed to upset the balanced federal/state responsibilities under the FCAA. ExxonMobil commented that it supports the commission and the EPA crediting the HGA SIP with an additional 60 tpd of federally preempted emission reductions that will occur over the next ten years. Harris County commented that the commission should work with the EPA to accelerate the implementation schedule for federally preempted emissions so that at least one-half of the related emission reductions are achieved by 2007, and that as a part of this process, the commission should delineate federal assignments detailing the engine standards and emission reductions necessary to achieve real and sustainable pollution reductions.

The commission agrees with the commenters that emission reductions from federally preempted sources would provide benefits for the HGA SIP demonstration, and the inability of the commission to regulate certain source categories has necessitated the use of other ozone control strategies. However, the commission understands that the EPA SIP approval process does not provide a mechanism for credit for emission reductions that occur after the attainment date. The commission understands that the EPA is not currently considering accelerating implementation schedules for existing federal rules. The commission is working with the EPA to determine the availability of SIP credit for many nontraditional control strategy mechanisms, like economic incentive programs and flexibility for preempted source categories. Additionally, the commission is working with the EPA to determine an appropriate federal contribution credit available for the HGA SIP.

WM commented that the commission should explore other alternatives such as the extension of the attainment deadline in order to provide sufficient time for new, low-emission equipment to penetrate the market.

The FCAA requires that a state have no more than one exceedance of the NAAQS in the year preceding the extension year, and that the state has complied with all requirements and commitments in the applicable implementation plan, prior to EPA granting such an extension. There is no provision in the FCAA or EPA guidance for EPA granting an extension in the absence of this data. However, the commission is committed to working with EPA and all interested parties to provide opportunities for new, low-emission equipment availability within the HGA nonattainment area.

Two individuals requested that the mandatory element of this rule be deleted to allow for a voluntary program. Another individual commented that the rule should be voluntary on equipment predating 1992. The Mayor of Houston urged the commission to work with industry to try to develop voluntary agreements in order to avoid lawsuits.

The EPA provides for the inclusion of voluntary programs or measures as part of the attainment demonstration, but limits the amount of emission reduction credit that may be claimed from such measures, due to the fact that the programs are not enforceable mechanisms. In accordance with EPA policy, the commission included some voluntary programs as part of the HGA SIP. The HGAC is the entity responsible for the development and implementation of these programs, which are detailed in the HGA SIP as the Voluntary Mobile Emissions Reduction Program (VMEP). If the adopted rule became voluntary it could not be counted as an enforceable measure obtaining emission reductions for the demonstration of attainment. As stated elsewhere in this preamble, the emissions reductions associated with these rules are necessary for the attainment of the NAAQS in the HGA area. The NO_x emissions from non-road equipment comprise 12% of the HGA area's total NO_x emissions. Because of this significant contribution that the equipment affected by these rules makes to the HGA area's ozone levels, it is essential that the rules be implemented along with the other rules and measures included in this SIP revision in order for the HGA area to demonstrate attainment with the federal ozone standard. It is possible for voluntary measures to be made enforceable through agreements and in that case they can be counted toward the SIP. The commission included a provision in these rules which would allow these enforceable agreements to be counted toward compliance with the rules. The commission encourages efforts to reach enforceable agreements as suggested by the Mayor of Houston, and looks forward to working with all interested participants.

Two individuals, ABC, AGC-Texas, BCCA, ED, ARTBA, Harris County, HCIC, AGC- Houston, PHA, Spring Valley, Texas City, the Houston MPO, and WM commented that the commission should provide for economic incentive programs to encourage development of new technologies, achieve earlier and/or greater reductions in pollution, and substitute for other rule proposals which may be costly and difficult to meet and enforce. The first individual, Spring Valley, and the Houston MPO commented that the rules should be replaced with an economic incentive program. The second individual and WM commented that the commission should consider voluntary rules that are part of an incentive program. ABC and BCCA commented that a diesel equipment incentive plan should be developed and that such plan would remove more NO_x emissions than both the construction workday shift rule and the accelerated Tier 2/Tier 3 rule combined. AGC-Texas commented that the commission should replace these rules with a market-based incentive program similar to the California Carl Moyer program. AGC-Houston commented that they support State Senator Buster Brown's proposal of developing legislation to fund an incentive program patterned after the Carl Moyer program in California. ED commented that the rules should be supplemented with market-based strategies that can be implemented immediately.

The commission agrees that economic incentive programs can potentially be an effective tool for achieving air quality. One such program is the Carl Moyer program in California. That program appears to be successful in providing flexibility to the regulated industry while still achieving reductions in air emissions. The California program is authorized by and funded through the California state legislative process; however, such legislative approval does not currently exist for a similar Texas program. The commission will continue to try to identify economic incentives which it has authority to implement. Because the commission agrees that market-based incentive programs can be an important component in encouraging development of new technologies and/or greater or more cost-effective emission reduction strategies, the commission has provided for the inclusion of economic incentive programs as a component of the HGA SIP in the future.

In addition, these particular rules do provide for the regulated entity to submit an alternative plan to achieve equivalent emission reductions. This alternative would enable regulated entities to take advantage of an economic incentive program which is developed in the future. The commission will continue to work with industry representatives to identify options for compliance which may currently exist or which may become available in the near future.

Three individuals commented that a tax credit or tax incentive should be given to companies to help replace their equipment.

The commission agrees that a tax credit or incentive would be helpful. Currently, 30 TAC Chapter 17, Tax Relief for Property Used for Environmental Protection, is the commission's program that provides tax relief for the purchase of pollution control property. On November 2, 1993, the Texas voters approved a constitutional amendment, commonly referred to as "Proposition 2," that provides an exemption from property taxation for pollution control property. The intent of the constitutional amendment was to ensure that capital investment undertaken to comply with federal, state, or local environmental mandates did not result in an increase in a facility's property taxes. Legislation implementing that amendment, House Bill 1920, was passed during the 73rd Texas Legislative Session which added a new §11.31 and §26.045 to the Texas Tax Code. The Tax Code provides that pollution control property could include any land purchased after January 1, 1994; or any structure, building, installation, excavation, machinery, equipment, or device; and any attachment or addition to or reconstruction, replacement, or improvement of property that is used, constructed, acquired, or installed wholly or partly to meet or exceed rules or regulations adopted by any federal, state, or local environmental agency for the prevention, monitoring, control, or reduction of air, water, or land pollution. Motor vehicles are specifically noted as being ineligible for an exemption under this provision of the Tax Code. The Tax Code contains a two-step process for securing an exemption from property taxes for pollution control property. An applicant must first receive a determination from the commission that the property is used for pollution control purposes. The applicant then can use this determination to apply to the local appraisal district for a property tax exemption.

The Mayor of Houston commented that the Construction Trades Association, EMA, and other interest groups are contemplating lawsuits for the purpose of removing these rules, among others, from the SIP. However, the city recognizes that without these rules, the area will not be able to meet the air quality standards. Therefore the city urges the commission to begin dialogue with the groups to develop enforceable alternatives. Texas City commented that the city is working with various industry groups to try to identify flexibilities for complying with the rules.

The commission agrees that these rules are needed for the HGA area to reach attainment. In order to achieve the maximum flexibility possible, the rules include a provision for an emission reduction plan. This is a plan submitted to the commission by a fleet owner or operator to show alternate methods of achieving emissions reductions equivalent to the emissions reductions that would be achieved by complying with the requirements of these rules. To develop a guidance document for this plan, a workshop has already taken place where stakeholders were invited and were given drafts of the requirements of the emissions reduction plan and asked for their input and comments. Further workshops will be held and the commission intends to work with the stakeholders to come up with an emissions reduction plan guidance document that will be workable and agreeable to everyone. The commission appreciates the efforts of all local entities, such as Texas City, which are working with industry to identify options for compliance.

Rule Coverage

Sierra-Houston and one individual commented that the rules should be adopted statewide.

The commission appreciates the support for state-wide applicability of the rules. The commission notes, however, that it is not obligated to adopt all rules statewide in order to satisfy its commitments under the SIP, nor is the commission required to do so under 42 USC. Three of the proposed measures which contained emissions reduction strategies that have been proposed for state-wide applicability are: California large-spark ignition engines; emissions banking and trading program (that portion of the rules which relates to the trading of emission reduction credits and discrete emission reduction credits); and cleaner diesel fuel (that portion of the proposed rules which relates to on-road fuel).

In evaluating whether to implement all of the rules statewide, the commission took into account many concerns, including the need for the marketplace to be able to respond to regulation, the possible impacts on transport and distribution systems, the possibility of increased costs and financial burdens on regulated entities, and the regional needs and issues associated with statewide mandates. The commission analyzed where emission reduction measures are most needed and where emissions reduction measures will be most effective in order to demonstrate attainment.

Equipment inventories and emission inventories do not support the implementation of these particular rules on a state-wide basis. These inventories and associated modeling show that the vast majority of heavy-duty diesel equipment is located and used in the DFW and HGA metropolitan areas, coinciding with the major concentrations of population in the state. Therefore, emissions from this equipment are also concentrated in those areas. In addition, these areas have air quality problems that are more serious than the rest of the state, primarily with ozone, the compound that these rules are designed to help reduce. These existing air quality problems, coupled with the geographic concentration of equipment usage and emissions, justifies implementing rules to control the emissions of ozone-forming compounds from heavy-duty diesel equipment in the DFW and HGA areas only, rather than statewide. Generally, mobile source emissions have more of a localized effect on ozone formation than elevated point sources. Given the more localized effect, and the fact that equipment subject to these rules do not typically travel over long distances, a state-wide application of the rules is not warranted at this time. However, these rules do not preclude other areas from implementing similar locally-regulated or voluntary programs to achieve similar benefits.

After careful consideration of all of these factors, the commission determined that the rules as proposed will achieve the needed emissions reductions and promote cleaner air throughout the State of Texas.

Montgomery Co. commented that their elimination from these rules would result in a difference of less than 1/100th of one ppb (0.01 ppb) of ozone. One individual commented that the rules such as this one should not apply in rural counties like Chambers and Liberty Counties.

Montgomery, Chambers, and Liberty Counties are all part of the HGA nonattainment area. The FCAA Amendments of 1990 provided new requirements for areas that had not attained the NAAQS for ozone, carbon monoxide, particulate matter, sulfur dioxide, nitrogen dioxide, and lead, and new requirements for SIPs in general. The EPA was authorized to designate areas failing to meet the ozone NAAQS as nonattainment and to classify them according to severity. The FCAA, §107(d)(4)(A)(iv) mandated that areas designated as serious, severe, or extreme for ozone that were within a metropolitan statistical area (MSA) or CMSA must have boundaries that include the entire MSA or CMSA. This requirement is supported by the legislative history for the FCAA Amendments in Senate Report Number 101-228, page 3399, "Because ozone is not a local phenomenon but is formed and transported over hundreds of miles and several days, localized control strategies will not be effective in reducing ozone levels. The bill, thus, expands the size of areas that are defined as ozone nonattainment areas to assure that controls are implemented in an area wide enough to address the problem." The FCAA provided the ability to exclude portions of the entire MSA or CMSA prior to designation if the state conducted, and EPA agreed, a study that proved that the geographic portion did not contribute significantly to violation of the NAAQS.

For existing areas currently included within a nonattainment area, the specific area must be redesignated as attainment in order to be removed from a nonattainment area designation. FCAA, §107(d)(3) provides that the EPA may not redesignate a nonattainment area, or a portion thereof, to attainment unless several criteria are met, which include: a determination that the area has attained the NAAQS; there is a fully approved SIP for the area; there is a determination that the improvement in air quality is due to permanent and enforceable reductions in emissions; there is an approved maintenance plan for the area; and the state has met all requirements for the area under Section 110 and Part D of the FCAA. Redesignation has not occurred for any portion of the HGA nonattainment area, and is not currently being considered.

However, even if a specific area within the HGA nonattainment area was redesignated by the EPA as attainment for ozone, reductions associated from all adopted ozone control strategies would still be necessary because of the requirements of the FCAA, §107(d)(3) and §175A which require maintenance plans for all redesignated areas. The maintenance plan must include the measures specified in §107(d)(3) and any additional measures that are necessary to ensure that the area continues to be in attainment with the NAAQS for ten years after the redesignation. Eight years after the redesignation, the state is required to submit an additional revision to the SIP for maintaining the NAAQS for another ten years after the end of the first ten-year period.

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies.

At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, several areas found that modeling attainment was made much more difficult, if not impossible, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide an improved control of ozone air pollution.

The commission conducted air quality modeling and upper air monitoring that found regional air pollution should be considered when studying air quality in Texas' ozone nonattainment areas. This work is supported by research conducted by the OTAG, the most comprehensive attempt ever undertaken to understand and quanitfy the transport of ozone. Both the commission and the OTAG study point to the need to take a regional approach to controlling air pollutants.

Five individuals commented that the rules would have an impact to farming and ranching. Two individuals commented that farmers and ranchers could not afford new equipment. Another individual commented that the rules would have an adverse economic impact on farmers. The commenter further stated that a project being undertaken by farmers in the Liberty, Jefferson, and Chamber counties will make "carbon credits" available to local industries which will not only have cash value but economic development advantage points. Three individuals commented that the cost of new equipment would be prohibitive and suggested that an agricultural exemption be put in place.

The commission disagrees that farmers and ranchers will experience a severe economic impact because the rules already contain an exemption, in §114.477(a)(6), for equipment which is used solely for agricultural purposes. This would include much, if not all, the equipment used by farmers and ranchers. Therefore, the rules would not affect farmers and ranchers unless they were using heavy-duty diesel equipment for non-agricultural purposes. Concerning the project that is being undertaken by the farmers, the commission supports all projects which have a potential to reduce emissions and support economic development.

TFA and TLC commented that small businesses such as logging contractors are not financially able to retire their equipment. They further state that the rules would be devastating to these contractors.

The commission disagrees that loggers will experience a severe economic impact because the rules do not require logging equipment such as chain saws, shredders, fellers, bunchers, and skidders to comply with these rules. The commission added language to the agricultural exemption to make clear that logging uses are also exempt.

Rule Effectiveness

Simonton commented that the commission should limit their concern to the exhaust emission levels, not the age of the equipment. An individual commented that we should look at the quality of what the equipment is putting out instead of just retiring old equipment. If the equipment is bad, then retirement may be necessary.

These rules are in fact based upon the exhaust emissions, not the age of the equipment. The rules require that certain percentages of a fleet must be certified to meet federal standards. The rules do not prohibit use of older equipment if it can be retrofitted to meet the same emission rates as newer, cleaner equipment. Additionally, if an operator chooses to submit an emissions reduction plan, older equipment may be included under that plan.

The commissions acknowledges that their may be old equipment that runs fine and is properly maintained, and therefore its emissions are acceptable for that equipment. However, the fact remains that the Tier 2 and Tier 3 engines will have more stringent standards than previous engines and equipment. Therefore, emissions levels will be lower for these fleets that contain Tier 2 and Tier 3 equipment or their equivalent.

An individual, Harris County, and the Houston MPO commented that the rules will not be effective. The individual stated the proposal is not based on proven technology, and Harris County stated that the rules are untried and untested. The Houston MPO commented that the Tier 2/Tier 3 standards are experimental, difficult to quantify, and market acceptance is uncertain.

The commission disagrees that these rules will not be effective. Although it is true that this strategy has never been implemented, the commission believes that it is reasonable, based on known and credible science, to reduce emissions from diesel equipment in order to meet the federal ozone NAAQS. The federal Tier 2 and Tier 3 standards are more stringent than Tier 1 and earlier equipment. It is therefore reasonable to conclude that a fleet that consists of only Tier 2 and Tier 3 equipment will emit less than a fleet that consists of a mix of unregulated, Tier 1, Tier 2, and Tier 3 equipment. The commission disagrees that market acceptance will be a problem because the Tier 2 and Tier 3 engine standards are a federal requirement, and therefore the manufacturers will have no choice but to produce such engines. The demand created by these rules may actually increase sales of the newer equipment which could help manufacturers recoup their development costs more quickly. The commission disagrees that the rules will be hard to quantify because the emission factors for this equipment are known and because the HGA inventory of construction equipment has been significantly refined. Through the use of the NONROAD model and the photochemical modeling, the rules have been shown to reduce 12.20 tpd of NO_x in 2007. For these reasons the commission asserts that the rules are based on well-accepted science and that they will be an effective emission reduction strategy.

Miscellaneous

Sierra-Houston opposes the use of emission credits and trading for these rules because they feel that the commission should be maximally reducing air emissions. Dow supports the commission position to allow credits for early upgrades to diesel equipment. Harris County supports the use of trading.

The commission disagrees that emission credit and trading should not be used to help with compliance to the rules. The commission believes that the flexibility offered through emission trading will provide opportunities for regulated entities to achieve significant emission reductions in a method that best suits that particular entity. This is just one tool that can be used in the emissions reduction plan to get the needed emission reductions. Furthermore, trading can only occur within the same nonattainment area so when a credit is generated, an actual reduction is taking place in the HGA nonattainment area. Finally, trading encourages early reductions and could give incentive for the development of cleaner technologies on an accelerated timetable.

Two individuals commented on the use of equipment after it has been "retired." One individual commented that the retiring of old equipment that is inefficient will result in such equipment ending up in third world countries such as South America and Africa. The commenter suggested that the equipment be scrapped, certified, and inspected. The second individual commented that this equipment should be dismantled.

The commission agrees that the "retirement" of old equipment may cause such equipment to end up in other areas of the region, state, nation, and possibly the world. The commission anticipates that this older equipment will be resold or transferred out of the area, thus mitigating the cost of compliance with these rules. Use of this older equipment in areas which do not have air quality problems is not cause for concern.

Concerning the dismantlement, scrappage, certification, and inspection of the "retired" equipment, the commission believes that the equipment should not be scrapped, because that equipment can be used in other areas outside of HGA. Furthermore, the commission does not believe certification and inspection of this "retired" equipment would serve any useful purpose.

Two individuals, Sierra-Houston, and Liberty County-Sheriff expressed concern over enforcement of the rules. More specifically, Sheriff Arthur wondered who is going to enforce the rules. He stated that they have a lot more serious problems in Liberty County to be concerned about. Sierra-Houston commented that the commission has not explained how enforcement will be done.

As with all of its rules, the commission will enforce the requirements after the rule compliance date and take appropriate action for noncompliance situations. The rules are enforced by commission staff in the regional offices, as well as local air pollution control programs. Local governments have the same power and are subject to the same restrictions as the commission under TCAA, §382.015, Power to Enter Property, to inspect the air and to enter public or private property in its territorial jurisdiction to determine if the level of air contaminants in an area in its territorial jurisdiction meets levels set by the commission. Local governments are not required to enforce commission rules, but may sign cooperative agreements with the commission to enforce the rules under TCAA, §382.115, Cooperative Agreements. Local programs can also enforce commission rules without signing a cooperative agreement. The authority of local governments to enforce air pollution requirements is specified in detail in TCAA, §§382.111 - 382.115, and local governments can institute civil actions in the same manner as the commission under Texas Water Code (TWC), §7.351.

The commission will work with local officials to ensure enforcement of the SIP and SIP rules. The commission has existing relationships with pollution control authorities in the City of Houston, Harris County, and Galveston County for enforcement of other commission rules. The agency will continue enforcement relationships with these entities and develop relationships with other local officials as needed to create effective enforcement mechanisms for the SIP and SIP rules.

Effected entities are required to report in accordance with 30 TAC §114.476, Reporting and Recordkeeping Requirements, and would have to keep those reports onsite. These rules have been written to allow enforcement to take place during operation by an investigator who requests the reports. An operator without reports on-site which include the piece of equipment being operated can then be cited with a violation of the rules. In addition, enforcement is possible by reviewing construction permits in the affected counties and performing spot checks at construction sites. The commission plans to use public education and public awareness as part of the enforcement strategy to ensure that the requirements of these rules are understood and that they will be enforced.

Lake Jackson commented that they have 22 pieces of non-road equipment and believe that they would be able to replace most of the equipment to comply with these rules. TxDOT commented that up to 138 pieces of equipment would be subject to these rules and that they would comply with these rules.

The commission appreciates Lake Jackson and TxDOT identifying these pieces of equipment for compliance with these rules.

EPA commented that the commission should provide information regarding the viability of the alternative means of compliance.

The EPA comments allude to the provision in the rules for the emissions reduction plan. In addressing the viability of alternative measures that could be used in such a plan, the commission is developing a guidance document for this plan. A workshop has already taken place where stakeholders were invited and were given drafts of the requirement of the emissions reduction plan and asked for their input and comments. Further workshops will be held and the commission intends to work with the stakeholders to come up with an emissions reduction plan guidance document that will be workable and agreeable to everyone.

ARTBA commented that the commission should not over-regulate the construction industry. They stated that the industry is already heavily regulated by the EPA emission standards on construction equipment.

The commission disagrees with this characterization of the construction industry as "heavily regulated." It is true that the EPA has issued emission standards for categories of non-road engines used by the construction industry. However, these standards were promulgated well after the federal statutory deadline and did not require any reductions until 1996, nor were any significant reductions required until the 2001 - 2006 time frame. The EPA has never regulated the non-road diesel fuel used in construction equipment, nor has the EPA regulated the hours which that equipment can be used. Until this year the commission had not regulated emissions from construction equipment, except incidentally as part of permitting actions. The commission has historically focused its regulations on point sources and on-road vehicles. Due to the efforts of state and federal agencies, these point sources and motor vehicles have become substantially cleaner over time and, as a result, the emissions from construction activities have increasingly made up a disproportionate amount of the emissions inventory. Given the amount of reductions needed to demonstrate attainment for the HGA SIP, the commission must require substantial reductions from all sectors including point sources, on-road vehicles, and non- road engines. Therefore, the commission does not agree that the construction industry is being over- regulated as part of the HGA SIP.

Three individuals commented about on-road diesels. One individual commented that the soot emissions coming from diesels cars are ten times higher than others. Two individuals commented that something should be down about the black smoke being emitted from diesel trucks. One of these individuals commented that it is a distraction in traffic, while the other individual commented that new equipment that is sold should have lower emissions, and existing equipment should be required to be replaced or upgraded. Both individuals commented that some sort of device be applied to existing diesel trucks to reduce emissions.

These commenters suggestions are beyond the scope of this rulemaking because these rules only affect non-road engines and equipment. However, the commission is considering for adoption, concurrent with this rulemaking, low-emission diesel fuel standards which would lower emissions from diesel trucks. Also, in the near future, new federal standards for on-road, heavy-duty diesel trucks will begin.

TxDOT suggested that the requirement in the rules that require 25% of the 50 to 100 hp fleet be Tier 2 by December 31, 2004, should be changed to 10%. They stated that because this equipment does not become available until 2004, then it may be hard to meet the 25% requirement.

The commission made no change in response to this comment. The commission believes that the 25% requirement will be achievable, and anticipated that OEMs will provide sufficient numbers of equipment in response to these rules because of the market that will be created. The commission also anticipates that many entities will choose to implement an emissions reduction plan, thus somewhat lessening the demand for the new equipment. However, when the SIP mid-course correction occurs in the 2003 to 2004 time frame, the commission will evaluate whether changes to the rule requirements will need to be made.

Brett & Wolf commented that for purposes of complying with the rules, a fleet owner or operator should be allowed choose to replace existing diesel-fueled equipment with units powered by gas turbines and/or fuel cells, and that these be counted as part of the fleet meeting the Tier 3 diesel standards under 30 TAC §114.472.

The commission believes that if it is feasible for a fleet owner or operator to replace diesel equipment with gas turbines and/or fuel cells, then they may do so. If all non-road equipment is converted to use these technologies then the fleet would not be subject to these rules, because gas turbines and/or fuel cells are not compression-ignition engines. Also, converting engines to these technologies is certainly a measure which could be included in an emissions reduction plan.

Sierra-Houston commented that the under 30 TAC §114.476, records should be maintained for five years because, this is the length of time the commission uses for compliance history.

The commission disagrees that records should be maintained for five years. Because the annual reports will be kept by the commission, more than three years of recordkeeping for an owner/operator is not deemed necessary. The commission made no change in response to this comment.

PHA commented that EPA approval of an emissions reduction plan should not be necessary. They commented that the commission has the requisite authority to approve the plans and should not require EPA approval. Therefore, PHA requested that 30 TAC §114.477(b) be revised to delete the phrase "and the EPA" with regard to plan approval.

The commission disagrees with this comment. Because this plan is part of a SIP strategy, an EPA review of the emissions reduction plans is prudent to ensure that the SIP is complete, approvable, and enforceable.

STATUTORY AUTHORITY

The new sections are adopted under TWC, §5.103, which authorizes the commission to adopt rules necessary to carry out its powers and duties under the TWC, and under Texas Health and Safety Code, TCAA, §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA. The new sections are also adopted under TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.019, which authorizes the commission to adopt rules to control and reduce emissions from engines used to propel land vehicles; and §382.039, which authorizes the commission to develop and implement transportation programs and other measures necessary to demonstrate attainment and protect the public from exposure to hazardous air contaminants from motor vehicles.

§114.477. Exemptions.

(a) The following non-road equipment powered by compression-ignition engines are exempt from §114.472 and §114.476 of this title (relating to Control Requirements; and Reporting and Recordkeeping Requirements):

(1) locomotives;

(2) underground mining equipment;

(3) marine engines;

(4) aircraft engines;

(5) airport ground support equipment;

(6) equipment used solely for agricultural and/or logging purposes which includes, but is not limited to, tractors, balers, combines, sprayers, swathers, and skidders;

(7) equipment used exclusively for emergency operations to protect public health and safety or the environment; and

(8) equipment used exclusively for freezing weather operations.

(b) Owners or operators who submit an emission reduction plan by May 31, 2002, which is approved by the executive director and the EPA no later than May 31, 2003, will be exempt from §114.472 and §114.476 of this title in the counties listed in §114.479 of this title (relating to Affected Counties) upon implementation of the rules of this division on December 31, 2004. The executive director may allow plans to be submitted after May 31, 2002. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division. In order to be approved, the plan must demonstrate nitrogen oxide reductions equivalent to those required by §114.472 of this title and must contain adequate enforcement provisions. The operators may submit a plan for exemption from the control requirements of §114.472 of this title, §114.482 of this title (relating to Control Requirements), or both.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009079
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

DIVISION 9. HOUSTON/GALVESTON CONSTRUCTION EQUIPMENT OPERATING RESTRICTIONS

30 TAC §§114.482, 114.486, 114.487, 114.489

The Texas Natural Resource Conservation Commission (commission) adopts new §114.482, Control Requirements; §114.486, Record keeping Requirements; §114.487, Exemptions; and §114.489, Affected Counties and Compliance Dates. The commission adopts these revisions to add new Division 9, Houston/Galveston Construction Equipment Operating Restrictions; to Subchapter I, Non-road Engines; Chapter 114, Control of Air Pollution from Motor Vehicles; and corresponding revisions to the state implementation plan (SIP). The commission adopts these new sections in Chapter 114 and revisions to the SIP in order to control ground-level ozone in the Houston/Galveston (HGA) ozone nonattainment area. The adopted sections are one element of the control strategy for the HGA Post-1999 Rate-of-Progress (ROP)/Attainment Demonstration SIP. New §§114.482, 114.486, 114.487, and 114.489 are adopted *with changes* to the proposed text as published in the August 25, 2000 issue of the *Texas Register* (25 *TexReg* 8240).

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

HGA SIP Background and Historical Summary

The HGA ozone nonattainment area is classified as Severe-17 under the Federal Clean Air Act (FCAA) Amendments of 1990 (42 United States Code (USC), §§7401 et seq.), and therefore is required to attain the one-hour ozone standard of 0.12 parts per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined by Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties, has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of its Post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base-case episodes, adopted rules to achieve a 9% ROP reduction in volatile organic compounds (VOC), and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary nitrogen oxides (NO_x) waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base-case episodes which marginally exhibited model performance in accordance with the United States Environmental Protection Agency (EPA) modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data-gathering exercise known as the COAST study. The state believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, the EPA policy regarding SIP elements and time lines went through changes. Two national programs in particular resulted in changing deadlines and requirements. The first of these programs was the Ozone Transport Assessment Group. This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in this study, and it has been concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that has impacted the SIP planning process is the revisions to the national ambient air quality standard (NAAQS) for ozone. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, the EPA proposed an interim implementation plan (IIP) that it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development time lines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, that standard would continue to apply until it is attained. The FCAA requires that HGA attain the standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998 a revision to the HGA SIP which contained the following elements in response to the EPA guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by Subpart 2 of Title I of the FCAA to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the state eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs as well as an acceleration simulation mode equivalent motor vehicle inspection and maintenance program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory state-wide programs adopted or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon Scenario VIf); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review; and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-99 ROP plan by December 31, 2000; to perform a mid- course review by May 1, 2004; and to perform modeling of mobile source emissions using the EPA mobile source emissions model (MOBILE6), to revise the on-road mobile source budget as needed, and to submit the revised budget within 24 months of the model's release. In addition, if a conformity analysis is to be performed between 12 months and 24 months after the MOBILE6 release, the state will revise the motor vehicle emissions budget (MVEB) so that the conformity analysis and the SIP MVEB are calculated on the same basis.

In order for the state to have an approvable attainment demonstration, the EPA has indicated that the state must adopt those strategies modeled in the November submittal and then adopt sufficient controls to close the remaining gap in NO_x emissions. The modeling and other analysis supporting these rules and the HGA SIP indicate a gap of approximately 91 tons per day (tpd) of NO_x reductions is necessary for an approvable attainment demonstration. The expected emissions shift from these rules are necessary to successfully demonstrate attainment.

The emission reduction requirements included as part of this SIP revision represent substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, have worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area have formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

This rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000 and planned to be submitted to EPA by December 31, 2000.

The amount of NO_x reductions required for the area to attain the ozone NAAQS has 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 reduction strategies. The FCAA, 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 oversight committee. Commission staff have continued to improve the air quality modeling technology and refine emission inventory data. Numerous emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources, on- road and non-road mobile sources, and area sources were analyzed in multiple iterations of modeling, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling and other analysis submitted for public hearing and comment concurrently with the HGA SIP show that a significant amount of NO_x reductions practicably achievable are necessary from ozone control strategies in order for the HGA nonattainment area to achieve the ozone NAAQS by 2007, including reductions from surrounding counties included in the HGA consolidated metropolitan statistical area (CMSA).

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies. At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, a dynamic commonly referred to as transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The current SIP revision contains rules, enforceable commitments, photochemical modeling analyses, and calculation of the remaining NO_x required to reach attainment (gap calculation) in support of the HGA ozone attainment demonstration. In addition, this SIP contains post- 1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contains enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit a mid-course review.

The HGA ozone nonattainment area will need to ultimately reduce NO_x by more than 750 tpd to reach attainment with the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of the HGA construction equipment operating restrictions program will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area.

Purpose and Summary of Proposed Rules

The purpose of these rules is to establish a restriction on the use of construction and industrial equipment (non-road, heavy-duty diesel equipment rated at 50 horsepower (hp) and greater) as an air pollution control strategy to delay the emissions of NO_x, a key ozone precursor, until after noon in order to limit ozone formation. The non-road mobile source category is one of the few sources of ozone-forming emissions that is not currently regulated by state or federal rules. Federal controls such as cleaner-burning engines and cleaner-diesel fuel have been proposed, but are not scheduled to be implemented until the 2004 time frame.

The adopted revisions will provide a similar restriction on the use of construction and industrial equipment as that previously adopted by the commission for the Dallas/Fort Worth (DFW) ozone nonattainment area, except that the effective period for the HGA ozone nonattainment area is between the hours of 6:00 a.m. and noon, from April 1 through October 31. The affected area includes the following counties within the HGA nonattainment area: Brazoria, Fort Bend, Galveston, Harris, and Montgomery. The contribution towards the reduction in ozone levels from restricting the hours of operation of construction and industrial equipment is an essential component of the control strategy and is necessary for the HGA ozone nonattainment area to demonstrate attainment with the ozone NAAQS. However, based on estimated population, estimated population growth, and estimated emissions developed using EPA-approved methodologies, the commission believes it is not necessary to include Chambers, Liberty, and Waller Counties in the adopted rules. This issue is discussed in greater detail in the ANALYSIS OF TESTIMONY section of this preamble.

The effective date of the amended rules for HGA will be April 1, 2005. The commission established an effective date in 2005 to allow manufacturers time to produce and release new cleaner-burning equipment and retrofit technology, which would enable equipment operators to plan for and implement purchases of this equipment before rules concerning restrictions on the operation of construction and industrial equipment become effective.

Equipment Classification

The equipment to which the rules concerning operating restrictions apply includes all non-road, heavy-duty diesel equipment classified as "construction equipment" or "industrial equipment," rated at 50 hp and greater, regardless of how that equipment is being used. "Construction equipment" includes, but is not limited to, pavers, tampers/rammers, plate compactors, concrete pavers, rollers, scrapers, paving equipment, surfacing equipment, signal boards/light plants, trenchers, bore/drill rigs, excavators, concrete/industrial saws, cement and mortar mixers, cranes, graders, off-highway trucks, crushing/processing equipment, rough terrain forklifts, rubber tire loaders, rubber tire tractors/dozers, tractors/loaders/backhoes, crawler tractors/dozers, skid steer loaders, off-highway tractors, and dumpsters/tenders. "Industrial equipment" includes, but is not limited to, aerial lifts, forklifts, sweepers/scrubbers, other general industrial equipment, other material handling equipment, air conditioning/refrigeration equipment, and terminal tractors. Agriculture equipment, such as tractors, combines, balers, agricultural mowers, agricultural sprayers, irrigation sets, and tillers greater than six hp, are not considered to be construction or industrial equipment, and are therefore not regulated under these rules.

Ozone Formation

Ozone is formed through chemical reactions between natural and man-made VOC and NO_x emissions in the presence of sunlight. The critical time for the mixing (chemical reactions) of NO_x and VOC is early in the day, and thus, higher ozone levels occur most frequently on hot summer afternoons. By delaying the hours of operation of construction and industrial equipment, and delaying the release of NO_x emissions until after noon during the time period between April 1 though October 31 in the HGA nonattainment area, the NO_x emissions are less likely to mix in the atmosphere with other ozone-forming compounds until after the critical mixing time has passed. Therefore, production of ozone will be stalled until later in the day when optimum ozone formation conditions no longer exist, ultimately minimizing the peak level of ozone produced.

This strategy is not dependent on atmospheric conditions to reduce ozone formation, as such strategies are disfavored by 42 USC, §7423. Instead, the strategy creates reductions in the amount of NO_x added to the atmosphere by construction and industrial equipment during the time of day when those emissions have been shown to contribute to exceedances of the ozone NAAQS. The use of "time of day" restrictions such as this for NAAQS compliance strategies was supported by the EPA in their non-road mobile source rules.

Emissions Reduction Plan

This rule contains a provision that allows operators to submit an emissions reduction plan by May 31, 2002, which, if approved by the executive director and the EPA by May 31, 2003, could allow the operation of construction or industrial equipment between the hours of 6:00 a.m. and noon during the restricted months. The executive director may allow plans to be submitted after May 31, 2002. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division. The commission anticipates that by offering this exemption in the HGA area, equipment manufacturers will invest in additional emission reduction research for construction and industrial equipment, and therefore advance the state of the art in emission reduction technology.

The emissions reduction plan must describe in detail how the operator will reduce NO_x emissions no later than April 1, 2005 by an amount equivalent to the total NO_x reductions that would have been achieved if the operator had otherwise complied with the rules. Owners or operators may submit plans to apply for exemption from either the construction equipment operating restrictions rules, the accelerated purchase of non-road heavy-duty diesel equipment rules, or from both sets of rules. The plans must contain emission reductions equivalent to the total NO_x reductions that otherwise would have been required by the rules, and must describe how the operator plans to ensure compliance with the provisions of the rules. Examples of possible modifications which may result in emission reductions include using new, cleaner-burning equipment, replacing existing equipment with cleaner-burning engines, retrofitting existing equipment with emissions-reducing technology, using emissions-reducing fuel, changing hours of operation, restricting equipment idling, and participating in an emissions banking and trading program. For example, an owner or operator may obtain emission reduction credits (ERCs), mobile emission reduction credits (MERCs), discrete emission reduction credit (DERCs), or mobile discrete emission reduction credit (MDERCs) in accordance with this section and 30 TAC Chapter 101 (General Air Rules), §101.29 (Emission Credit Banking and Trading). Note: in a concurrent rulemaking (rule log number 1998-089-101-AI), the emission credit banking and trading rules are being moved to Chapter 101, Subchapter H (Emissions Banking and Trading), Division 1 (Emission Credit Banking and Trading) and Division 4 (Discrete Emission Credit Banking and Trading).

In order to quantify the NO_x and VOC emission reductions and equivalent ozone reductions resulting from the fleet modifications, the commission will apply the same construction and industrial equipment emission inventory factors used in the modeling to develop these rules. The commission is developing a guidance document that will be available by May 31, 2001 to assist operators in developing their plans. The guidance document will outline requirements for the emissions reduction plan exemption in detail. A working draft of the guidance document is currently available. The commission is accepting comments on it from all interested parties until May 1, 2001, and is holding workshops for all interested parties to give input into the development of the document. The commission estimates that these rules will result in an approximate 7.9 tpd shift of NO_x emissions from morning to afternoon, which is equivalent to about 6.7 tpd of NO_x reductions.

The commission is requiring submission of the plans by May 31, 2002 to allow sufficient time to review and quantify the collective emission reductions the plans propose. The executive director and the EPA will complete the reviews by May 31, 2003, which coincides with the planned mid-course review of all control measures included in the SIP. After reviewing the plans, the executive director will determine whether the collective emission reductions proposed by the plans are equivalent to the NO_x reductions that would have been achieved from implementing the underlying rules. The commission will implement the construction equipment operating restrictions rules on April 1, 2005 and the accelerated purchase rules on December 31, 2004, as adopted, for operators who did not submit plans or whose plans were not approved.

The commission has determined that the fiscal implications may be significant due to the shift in work hours. The restriction in the hours of operation may require that companies adjust their work schedules to comply with these restrictions.

Additional Flexibilities

The commission solicited comment on the need for additional flexibility relating to rule content and implementation which have not been addressed in this or other concurrent rulemakings. Such flexibility may be available for both mobile and stationary sources. Additional flexibility may be achieved through innovative and/or emerging technology which may become available in the future. Additional sources of funds for incentive programs may become available to substitute for some of the measures considered here. The commission received comments from 40 persons and eight individuals regarding these issues. The comments are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

SECTION BY SECTION DISCUSSION

The adopted new §114.482 establishes time of day operating restrictions for construction equipment. This new section restricts the operation of any non-road diesel construction and industrial equipment of 50 hp and above, between the hours of 6:00 a.m. and noon, from April 1 through October 31. The description of the time period of the restriction was changed from "Daylight Savings Time" to "April 1 through October 31" in order to be consistent with other rules. In response to a comment that the definition of construction equipment required clarification, the commission added the term "industrial" in the preamble and rule language in each instance where the types of affected equipment is mentioned, and also added to the preamble a list of the specific types of equipment included in the categories "construction and industrial equipment" that are subject to these rules.

The adopted new §114.486 requires all persons subject to the provisions of §114.482 to maintain daily records of equipment operated in the affected counties. The term "industrial" was added to subsection (a) of this section to clarify the definition of affected equipment. The term "working" was added to subsection (b) of this section to clarify the time limit to provide records upon request is to be working days rather than calendar days.

The adopted new §114.487 provides exemptions from the control requirements of §114.482 and the recordkeeping requirements of §114.486. The term "industrial" was added to subsection (a) of this section to clarify the definition of affected equipment. These exemptions include diesel equipment used exclusively for situations involving emergency operations, and diesel equipment being used for mixing, transporting, pouring, or processing wet concrete. For purposes of these rules, emergency equipment is defined as equipment being used to repair facilities, devices, systems, or infrastructure that have failed, or are in danger of failing, in order to prevent immediate harm to public health, safety, or the environment. Therefore, language was added to subsection (a)(1) to clarify this aspect of the exemption. However, this exemption does not cover equipment being used for routine maintenance of facilities, devices, systems, or infrastructure, since such activities are not essential to prevent greater immediate harm to public health, safety, or the environment.

Subsection (b) contains an exemption that allows operators to submit an emissions reduction plan by May 31, 2002, which, if approved by the executive director and the EPA by May 31, 2003 could allow the operation of construction or industrial equipment between the hours of 6:00 a.m. and noon during the restricted months. The executive director may allow plans to be submitted after May 31, 2002. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division. Each plan must contain adequate enforcement provisions, and must demonstrate emission reductions equivalent to the total NO_x reductions that would otherwise have been achieved under the rules from which the owner/operator is applying for exemption: construction equipment operating restrictions in §114.482, accelerated purchase of Tier 2/Tier 3 diesel equipment in §114.472, or both sets of rules. The language in subsection (b) was revised to clarify that the requirement to demonstrate equivalent NO_x reductions applies to the specific rules from which an exemption is being requested.

The commission is developing a guidance document that will be available May 31, 2001 to assist operators in developing their plans. The guidance will outline requirements for the plan exemption in detail. A working draft of the guidance is currently available from the commission. A working draft of the guidance document is currently available. The commission is accepting comments on it from all interested parties until May 1, 2001, and is holding workshops for all interested parties to give input into the development of the document.

The adopted new §114.489 specifies the counties in which these rules are applicable, and the dates and times the rules are effective. The affected counties include the counties of Brazoria, Fort Bend, Galveston, Harris, and Montgomery Counties. Based on estimated population, estimated population growth, and estimated emissions developed using EPA-approved methodologies, the commission believes it is not necessary to include Chambers, Liberty, and Waller Counties in the adopted rules. This issue is discussed in greater detail in the ANALYSIS OF TESTIMONY section of this preamble. The compliance date for the HGA area is April 1, 2005. The compliance date was changed to be consistent with the compliance dates of other rule packages.

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed the rulemaking in light of the regulatory analysis requirements of Texas Government Code,

§2001.0225, and 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 rules are intended to protect the environment and/or reduce risks to human health from environmental exposure to ozone and, although the commission does not have cost estimates at this time, construction delays could affect a sector of the economy in a material way. The adopted rules are intended to implement an operating-use restriction which would prohibit the operation of heavy-duty diesel construction and industrial equipment between the hours of 6:00 a.m. and noon, from April 1 through October 31. These rules are part of a strategy to reduce the formation of ozone in the HGA nonattainment area by delaying NO_x emissions from construction and industrial equipment until later in the day when optimal conditions for the formation of ozone no longer exist. The rules were developed to help the HGA ozone nonattainment area demonstrate attainment of the ozone NAAQS. The rules are one element of the HGA Post-1999 ROP/Attainment Demonstration SIP.

These adopted rules do not meet any of the four applicability criteria for requiring a regulatory analysis of "major environmental rule" as defined in the Texas Government Code. Section 2001.0225 applies only to a major environmental rule the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

As discussed earlier in this preamble, this rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000, and planned to be submitted to EPA by December 31, 2000.

These rules do not exceed an express standard set by federal law, since they implement requirements of the FCAA Provisions of 42 USC, §7410, require 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. These rules were specifically developed as part of an overall control strategy to meet the ozone NAAQS set by the EPA under 42 USC, §7409. While 42 USC, §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 42 USC, Chapter 85, Air Pollution Prevention and Control). It is true that 42 USC 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 42 USC. The provisions of 42 USC 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 42 USC allows states to develop their own programs, this flexibility does not relieve a state from developing a program that meets the requirements of 42 USC, §7410. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410 and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to shift the morning NO_x emissions, thereby limiting formation of afternoon peak ozone levels. Specifically, as noted elsewhere in this rule preamble, the limitation in afternoon peak ozone production associated with these rules is a necessary element of the attainment demonstration required by the FCAA.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. By policy, the EPA requires photochemical grid modeling to demonstrate whether the 42 USC, §7511a(f), NO_x measures would contribute to ozone attainment. The commission has performed photochemical grid modeling which predicts that NO_x emission strategies, such as those required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The 42 USC, §7511a(f), exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under 42 USC, §7511a(f), was based on the finding that NO_x emissions management in HGA is necessary for attainment of the ozone standard. Therefore, the adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

During the 75th Legislative Session, Senate Bill (SB) 633 amended the Texas Government Code to require agencies to perform a regulatory impact analysis (RIA) of certain rules. The intent of SB 633 was to require agencies to conduct a RIA of extraordinary rules. 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 adopted rules from the full analysis unless the rule was a major environmental rule that exceeds a federal law. As previously discussed, 42 USC 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 proposes and adopts SIP rules. The legislature is presumed to understand this federal scheme. If each rule adopted 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. Because 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 42 USC.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd, Inc.*, 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied)*; and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.,* 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling within this standard. The commission has substantially complied with the requirements of §2001.0225.

Rules adopted for inclusion in the SIP fall within the exception in Texas Government Code, §2001.0225(a), because they are required by federal law. The commission performed photochemical grid modeling which predicts that NO_x emission shifting, such as that required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area. This rulemaking does not exceed an express requirement of state law. This rulemaking is intended to result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law. The rulemaking does not exceed a standard set by federal law, does not exceed an express requirement of state law (unless specifically required by federal law), and does not exceed a requirement of a delegation agreement. The rulemaking was not developed solely under the general powers of the agency, but rather was specifically developed to meet the federal NAAQS under the authority of the Texas Clean Air Act (TCAA), §§382.011, 382.012, 382.017, 382.019, and 382.039.

The commission solicited public comment on the draft RIA and received 14 comments. These comments are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

TAKINGS IMPACT ASSESSMENT

The commission evaluated this rulemaking action and performed an analysis of whether the proposed rules are subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. The specific purpose of the rulemaking action is to establish a construction and industrial equipment operating restriction which will delay until after noon NO_x emissions that lead to high levels of ground-level ozone production. This rulemaking will act as an air pollution control strategy to reduce ozone levels necessary for the HGA ozone nonattainment area to be able to demonstrate attainment with the ozone NAAQS. The affected area includes the following counties within the HGA nonattainment area: Brazoria, Fort Bend, Galveston, Harris, and Montgomery. Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rules do not directly prevent a nuisance, prevent an immediate threat to life or property, or prevent a real and substantial threat to public health and safety, the rules partially fulfill a federal mandate under the 42 USC, §7410. Specifically, the emissions shift under these rules was developed in order to meet the ozone NAAQS set by the EPA under the 42 USC, §7409. In addition, §2007.003(b)(4) provides that Chapter 2007 does not apply to these adopted rules since it is reasonably taken to fulfill an obligation mandated by federal law. This action is taken in response to the HGA area exceeding the NAAQS for ground- level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by shifting ambient NO_x and reducing peak ozone levels in HGA. Attainment of the ozone standard will require substantial NO_x emissions control and management. Any NO_x emissions shifting resulting from the current rulemaking is no greater than what the best scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard.

Therefore, the purpose of the rulemaking action is to implement a construction and industrial equipment time of day operating restriction necessary for the HGA nonattainment area to meet the ozone NAAQS established under federal law. The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explain in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission has determined that the adopted 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 rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with the CMP. As required by 31 TAC §505.11(b)(2) and 30 TAC §281.45(a)(3), relating to actions and rules subject to the CMP, commission rules governing air pollutant emissions must be consistent with the applicable goals and policies of the CMP. The commission has reviewed this rulemaking for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and determined that the action is consistent with the applicable CMP goals and policies. The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(1)). No new sources of air contaminants will be authorized and ozone levels will be reduced as a result of these rules. The CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations in 40 Code of Federal Regulations (CFR), to protect and enhance air quality in the coastal area (31 TAC §501.14(q)). This rulemaking action complies with 40 CFR Part 50, National Primary and Secondary Ambient Air Quality Standards, and 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal Of Implementation Plans. Therefore, in compliance with 31 TAC §505.22(e), this rulemaking action is consistent with CMP goals and policies.

The commission solicited comments on the consistency of the proposed rules with the CMP during the public comment period but received none.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000. The following persons and 124 individuals provided oral testimony and/or submitted written testimony: 1st Infinity Enterprises, Inc. (Infinity); AAA Asphalt Paving, Inc. (AAA Asphalt); American Road & Transportation Builders Association (ARTBA); American Short Line Railroad Association (ASLRRA); Associated Builders & Contractors of Greater Houston (ABC); Associated General Contractors of America, Houston Chapter (AGC-Houston); Associated General Contractors of Texas (AGC-Texas); Association of American Railroads (AAR); Baker Botts, L.L.P. (Baker Botts); Balfour Beatty (Balfour); Bearden Contracting Company (Bearden); Bell Janitorial (Bell); BFI Waste Systems of North America, Inc. (BFI); Boring & Tunneling Company of America, Inc. (BorTunCo); Brazos River Constructors, Inc. (BRC); Brett & Wolff, L.L.C. (Brett & Wolff); Brown & Brown Insurance (Brown & Brown); Business Coalition for Clean Air (BCCA); Casa Linda Remodeling, Inc. (Casa Linda); CCC Group, Inc. (CCC); C.E. Barker, Inc. Underground Construction (Barker); Centex Homes (Centex); Chambers County Judge Jimmy Sylvia (Chambers County); Cherry Demolition (Cherry); Chevron Phillips Chemical Company, L.P. (Chevron); City of La Porte (La Porte); City of Missouri City (Missouri City); City of Simonton (Simonton); City of Spring Valley (Spring Valley); Clean Air Partnership (CAP); Clear Lake Area Chamber of Commerce (Clear Lake COC); Coastal Water Authority (CWA); Conrad Construction Company (Conrad); Contractor Technology, Inc. (CTI); Dayton Pipe Company (Dayton Pipe); Demar Constructors (Demar); Dina Industries, Inc. (Dina); Dow Chemical Company (Dow); Drews Custom Homes (Drews); Earth Material Services, L.L.C. (Earth Material); E.E. Reed Construction, L.C. (Reed); Ella S.A. Contracting, Inc. (Ella); Emerald Builders (Emerald); Neal, Gerber, & Eisenberg on behalf of Engine Manufacturers Association (EMA); Enterprise Products Operating L.P. (Enterprise); Environmental Defense (ED); Excalibur Construction, Inc. (Excalibur); ExxonMobil Corporation (ExxonMobil); GR Birdwell Construction, Inc. (GR Birdwell); Grandparents of East Harris County (GEHC); Greater Houston Builders Association (GHBA); Harris County Judge Robert Eckels (Harris County); Hassell Construction, Inc. (Hassell); Higgs Custom Homes (Higgs); Hoar Construction (Hoar); Holmes Homes, Inc. (Holmes); Houff Energy Corporation (Houff); Benthul & Kean on behalf of Houston Construction Industry Coalition (HCIC); Houston Contractors Association (HCA); Houston Metropolitan Planning Organization Transportation Policy Council (Houston MPO); Independent Electric Contractors, Inc. (IEC); JB Services (JBS); J & S Contractors, Inc. (J & S); Jim Frankel Custom Homes (Frankel); Joel A. Trimm Construction Company, Inc. (Trimm); John Holland Construction Co., Inc. (Holland); Kinder Morgan, Inc. (Kinder Morgan); Kossman Contracting Company, Inc. (Kossman); Kvaerner; League of Women Voters of Texas (LVW-TX); Legacy Homes (Legacy); Legal Eagle Contractors Co. (Legal Eagle); Liberty County Judge Lloyd Kirkhall (Liberty County); Listo Company (Listo); Lyondell-Citgo Refining, L.P. (Lyondell-Citgo); Manhattan Construction Company (Manhattan); MB Western Industrial Contracting Company (MB Western); Ms Pamela Berger on behalf of Houston Mayor Lee Brown (Mayor of Houston); Mesa Mechanical, Inc. (MMI); Metropolitan Transit Authority (Metro); Mickie Service Company, Inc. (MSC); RMT, Inc. on behalf of Montgomery County (Montgomery County); Montgomery County Commissioner, Precinct 1, Mike Metter (Commissioner Metter); Montgomery County Judge Allen Sadler (Judge Sadler); Montgomery County Soil & Water Conservation District Number 452 (MCSWCD); Mothers for Clean Air (MCA); Mustang Tractor & Equipment Company (Mustang Tractor); N & S Construction Co., L.L.C. (N&S); National Aeronautics and Space Administration (NASA); National Motorists Association (NMA); National Solid Wastes Management Association (NSWMA); NBG Constructors, Inc. (NBG); NuHome Design, L.L.C. (NuHome); Nunez Construction Company, Inc. (Nunez); Paisan Construction Company (Paisan); Trinity Consultants on behalf of Pasadena Paper, Pasadena Pulp, and Donohue Industries Inc. (Pasadena/Donohue); Pat Hambrick Construction (Hambrick); Pate & Pate Enterprises, Inc. (Pate & Pate); Perry Homes; Phillips 66 Company (Phillips 66); PolyTech; Port of Houston Authority (PHA); Protherm Services Group (Protherm); Public Citizen; Reddico Construction Company (Reddico); Regional Air Quality Consensus Group on behalf of the Houston-Galveston Area Council (RAQCG); Reliant Energy, Inc. (REI); State Representative for District 16, Ruben Hope (Representative Hope); State Representative for District 130, John Culberson (Representative Culberson); Rhodia, Inc. (Rhodia); Rohm and Haas Chemical Company (Rohm and Haas); S&B Plant Services, Ltd. (S&B); Sandlin Companies (Sandlin); Sustainable Economic and Environmental Development Coalition (SEED); State Senator for District

11, Mike Jackson (Senator Jackson); Sierra Club Houston Regional Group (Sierra - Houston); Slack & Co. Contracting, Inc. (Slack); Small Business United of Texas (SBU Texas); Solutia; Sprint Sand & Clay, L.P. (Sprint Sand); Stephen Hann Custom Builders (Hann); TDIndustries, Inc. (TDIndustries); Jenkins & Gilchrist, L.L.P. on behalf of TXI Operations, L.P., (TXI); Texas Association of Builders (TAB); Texas Chemical Council (TCC); Texas Citizens for a Sound Economy (CSE); Texas Department of Transportation (TxDOT); Texas Forestry Association (TFA) in conjunction with the Texas Logging Council (TLC); Texas Oil & Gas Association (TxOGA); Trunkline Gas Company (TGC); U.S. Army Corps of Engineers (USACE); US Home Corporation (US Home); Union Carbide Corporation (Union Carbide); Union Pacific Railroad Company (Union Pacific); University of Texas System (UT); Vernor Material and Equipment (Vernor); and Waste Management (WM).

Commenters generally supporting the proposal included Kinder Morgan, LWV-TX, Metro, TGC and 15 individuals. Commenters generally opposing the proposal included Infinity, AAA Asphalt, ARTBA, ABC, AGC-Houston, AGC-Texas, AAR, ASLRRA, Baker Botts, Balfour, Bearden, Bell, BFI, BorTunCo, BRC, Brett & Wolff, Brown & Brown, BCCA, Casa Linda, CCC, Barker, Centex, Chambers County, Cherry, La Porte, Simonton, Spring Valley, CAP, Clear Lake COC, CWA, Conrad, CTI, Demar, Dina, Dow, Drews, Earth Material, Reed, Ella, Emerald, EMA, ED, Excalibur, ExxonMobil, GR Birdwell, GEHC, GHBA, Harris County, Hassell, Higgs, Hoar, Holmes, Houff, HCIC, HCA, IEC, JBS, Frankel, Trimm, Holland, Kossman, Kvaerner, Legacy, Legal Eagle, Liberty County, Listo, Manhattan, MB Western, Mayor of Houston, MMI, MSC, Commissioner Metter, Judge Sadler, MCSWCD, MCA, Mustang Tractor, N&S, NASA, NMA, NSWMA, NBG, NuHome, Nunez, Paisan, Hambrick, Pate & Pate, Perry Homes, Phillips 66, PolyTech, PHA, Protherm, Public Citizen, Reddico, RAQCG, REI, Representative Hope, Representative John Culberson, Rhodia, Rohm and Haas, S&B, Sandlin, SEED, Senator Mike Jackson, Sierra - Houston, Slack, SBU Texas, Sprint Sand, Hann, TDIndustries, TAB, TCC, CSE, TxDOT, TFA, TLC, TXI, TxOGA, USACE, US Home, Union Pacific, UT, Vernor, WM, and 89 individuals.

The following persons and 93 individuals suggested changes to the proposal as stated in the ANALYSIS OF TESTIMONY section of this preamble: Infinity, AAA Asphalt, ARTBA, ABC, AGC- Houston, AGC-Texas, AAR, ASLRRA, Baker Botts, Balfour, Bearden, Bell, BFI, BorTunCo, BRC, Brett & Wolff, Brown & Brown, BCCA, Casa Linda, CCC, Barker, Centex, Chambers County, Cherry, Chevron, La Porte, Missouri City, Simonton, Spring Valley, CAP, Clear Lake COC, CWA, Conrad, CTI, Dayton Pipe, Demar, Dina, Dow, Drews, Earth Material, Reed, Ella, Emerald, EMA, Enterprise, ED, Excalibur, ExxonMobil, GR Birdwell, GHBA, Harris County, Hassell, Higgs, Hoar, Holmes, Houff, HCIC, HCA, Houston MPO, IEC, JBS, J&S, Frankel, Trimm, Holland, Kinder Morgan, Kossman, Kvaerner, Legacy, Legal Eagle, Liberty County, Listo, Lyondell-Citgo, Manhattan, MB Western, Mayor of Houston, MMI, MSC, Commissioner Metter, MCSWCD, MCA, Mustang Tractor, N&S, NASA, NMA, NSWMA, NBG, NuHome, Nunez, Paisan, Pasadena/Donohue, Hambrick, Pate & Pate, Perry Homes, Phillips 66, PolyTech, PHA, Protherm, Public Citizen, Reddico, RAQCG, REI, Representative Hope, Rhodia, Montgomery County, Rohm and Haas, S&B, Sandlin, Sierra - Houston, Slack, SBU Texas, Solutia, Sprint Sand, Hann, TDIndustries, TAB, TCC, CSE, TxDOT, TFA, TLC, TxOGA, TGC, Union Carbide, USACE, US Home, Union Pacific, UT, Vernor, and WM.

Harris County supported the comments submitted by Houston MPO, RAQCG, and CAP. The comments submitted by the BCCA were supported by REI, ExxonMobil, Chevron, LP, Dow, and Phillips 66. The comments submitted by Texas Industry Project were supported by Reliant Energy, Inc., ExxonMobil Corporation, Dow Chemical Company, and Phillips 66 Company. The comments submitted by TCC were supported by ExxonMobil, Dow, and Phillips 66. ExxonMobil and Phillips 66 also supported the comments submitted TxOGA. The comments submitted by HCA were supported by Slack and Cherry. The comments submitted by GHBA were supported by Legal Eagle, NuHome, Legacy, and Perry Homes. The AGC-Houston supported the comments submitted by HCIC. The Mayor of Houston supported the comments submitted by Harris County.

ANALYSIS OF TESTIMONY

One individual commented that the public should be informed in simple terms how much pollution is generated per day and year by heavy construction equipment between 6 a.m. and noon.

For 1993, which is the base year for modeling for the HGA area, emissions from heavy-duty diesel construction equipment amounted to 42.4 tpd of NO_x.

One individual asked, "What is the benefit from this rule to Houston's air quality in terms of percentage improvement?"

The construction equipment operating restrictions rules shift 7.9 tpd of NO_x to the afternoon, which is equivalent to an approximate 6.7 tpd of NO_x reduction. This amounts to approximately 1% of the total NO_x reductions in the HGA area.

One individual asked, "What viable alternatives exist to this provision (e.g. alternative fuel incentives)?"

The exemption offered by submitting an emissions reduction plan which demonstrates equivalent reductions offers the possibility for an alternative compliance method. Also, local stakeholders in the HGA area have expressed an interest in the creation of programs designed to provide incentives for the achievement of earlier and/or greater reductions than those reductions anticipated from currently proposed control measures. Such incentive programs could be effective technology-forcing tools to obtain substantial innovation and ozone reductions in the most cost-effective manner possible. Possible components of one such program applicable to these rules could be the provision of funds on a competitive basis to entities operating both on- and non-road NO_x sources to assist in the incremental costs of cleaner equipment (which could encourage earlier implementation of new technologies, cleaner engines, and fuels). Other incentive programs could focus on tax incentives, subsidies, research and development, technological assistance, etc. The commission anticipates that such programs could be components of the HGA ozone nonattainment SIP, either as enforceable commitments, as potential future substitute measures based on per-ton reduction cost and total funding associated with the final scope of the programs, or as alternative methods of compliance with proposed control strategies. Any incentive program or other alternative method of compliance must result in emission reductions equivalent to those contained in these rules.

Sierra - Houston and one individual commented that there should not be exceptions to the rule.

The commission disagrees with this comment. The exemptions offered under these rules will either ensure equivalent emission reductions or will not result in significant emissions of ozone-forming compounds, so that the ozone reductions achieved by these rules will not be compromised. The commission is also committed to offering entities affected by the rules adopted under the SIP as much flexibility in complying with those rules as possible, while ensuring that the emission reductions the SIP is intended to achieve are not compromised. The exemptions allow operators to avoid the operating restriction while still contributing to the regional clean air goals. Specific justifications for the existing exemptions are as follows: Equipment, when used for situations involving emergency operations, including equipment that may have to be used to repair facilities or devices which have failed in order to prevent greater immediate harm to the environment or public health, is exempt in order to ensure protection of public health and the environment. Equipment used while mixing, transporting, pouring, or processing wet concrete is exempt because of the temperature sensitivity of these operations during the effective time period of these rules. In addition, the emissions from wet concrete processing equipment constitute a very minor contribution to the total emissions from construction and industrial equipment. Therefore, allowing this particular equipment to operate during the restricted hours is not expected to significantly impact peak ozone levels. The emissions reduction plan exemption offered under §114.487(b) provides flexibility to operators while maintaining ozone reductions equivalent to those that otherwise would have been achieved under these rules. Equipment owners/operators that submit a plan demonstrating equivalent emission reductions may be exempted from §114.482 and §114.486 of the rules. Local stakeholders in the HGA area have expressed an interest in the creation of programs designed to provide incentives for the achievement of earlier and/or greater reductions than anticipated from currently proposed control measures. Such incentive programs could be effective technology promoting tools to obtain substantial innovation and ozone reductions in the most cost-effective manner possible. Possible components of one such program could be the provision of funds on a competitive basis to entities operating both on- and non-road NO_x sources to assist in the incremental costs of acquiring cleaner equipment (which could in turn encourage earlier implementation of new technologies, cleaner engines, and fuels). Other incentive programs could focus on tax incentives, subsidies, research and development, technological assistance, etc. The commission anticipates that such programs could be components of the HGA ozone nonattainment SIP, as enforceable commitments, as potential future substitute measures based on per-ton reduction cost and total funding associated with the final scope of the programs, or as alternative methods of compliance with proposed control strategies. Any incentive program or other alternative method of compliance must assure emission reductions equivalent to those that would otherwise have been achieved by these rules.

AGC-Texas, CCC, Mustang Tractor, and three individuals commented that this rule unfairly singles out or "targets" the construction industry.

The commission disagrees with this comment. The commission has not singled out the construction industry. The commission provided in the rule preamble a list of the equipment covered by these rules, and clarified that the rules apply to all operators of non-road, heavy-duty diesel construction and industrial equipment rated at 50 hp and above, with the exception of agricultural users, regardless of how the equipment is being used. For example, equipment such as bulldozers used in sanitary landfills, non-road cranes used in demolition, and rubber tire loaders used in manufacturing and industrial operations are subject these rules. Construction and industrial equipment were specifically proposed under these rules because of their significant contribution to of NO_x emissions to the HGA area. The commission is adopting other rules and enforceable commitments for the HGA area to regulate emissions from other types of non-road diesel equipment, as well as on-road diesel equipment and vehicles. Reducing emissions from non-road diesel equipment is also addressed with the accelerated purchase of Tier 2/Tier 3 heavy-duty diesel equipment rules and the diesel emulsion measure. Emissions from on-road and non-road diesel equipment are being addressed through the clean diesel fuel rules which will be effective in 2002 for the 95-county central and eastern Texas region. Another measure affecting other types of non-road diesel equipment is the NO_x reduction systems program. As is evidenced by the adoption of these measures, the commission is not singling out any one industry in its efforts to reduce ozone levels to bring the HGA area into attainment with federal ozone standards.

One individual commented that the number of diesel engines operating non-road on construction sites in the HGA area is insignificant compared to the number of diesel engine trucks operating on the road, and that these vehicles are allowed to operate all hours of the day without limitation.

The commission disagrees with this comment. All diesel-powered vehicles and equipment registered to be used on-road must use federally certified on-road diesel fuel. Additionally, on-road diesel vehicles and diesel equipment are being covered in the low emission diesel fuel rules for the central and eastern Texas region. Under those rules, all diesel-powered, compression-ignition engines, both on-road and non-road, will be required to use low emission diesel when refueling within the 95- county central and eastern Texas region. Other measures adopted on December 6, 2000 with the HGA SIP revision will also result in reduced emissions from on-road diesel vehicles. These measures include diesel emulsion, NO_x reduction systems, and vehicle idling restrictions. Therefore, emissions from on-road diesel trucks are already less polluting than those from non-road diesel equipment, and are less harmful to human health and the environment.

Two individuals commented that establishing the effective date for this rule far off into the future adds credence to the conclusion that this measure is meant to be simply for appearance's sake. Projects that have passed some critical investment or decision point could be grandfathered while all new projects could be subject to an earlier effective date.

The commission disagrees with this comment. The commission believes that setting a 2005 effective date will allow affected persons to have ample time to plan and prepare for the rules' implementation. This additional time will also allow manufacturers time to produce new cleaner- burning equipment, fuels, and retrofit technology, which would enable equipment operators to plan for and implement purchases of this technology before rules concerning equipment operating restrictions become effective. The emissions reduction plan offered under §114.487(b) allows those equipment operators that submit a plan which demonstrates emission reductions equivalent to the reductions achieved for their fleet by the construction equipment operating restrictions rules to operate their affected equipment during the restricted hours. Therefore, if equipment operators are able to reduce emissions from their equipment by utilizing such technologies as retrofitting, cleaner-burning equipment, or cleaner fuels, which the effective date of 2005 would give manufacturers more time to make more widely available, then they would not be restricted from operating their equipment, and would not need to alter their schedules to accommodate the operating restrictions.

Infinity, AAA Asphalt, ARTBA, AGC-Houston, AGC-Texas, Balfour, Bell, Brett & Wolff, Brown & Brown, BCCA, CCC, Spring Valley, CAP, CWA, Demar, Dow, Reed, ED, ExxonMobil, Harris County, Hoar, HCIC, Houston MPO, Frankel, Kvaerner, Legacy, Legal Eagle, Manhattan, Mayor of Houston, MB Western, MMI, MCA, Mustang Tractor, NuHome, Nunez, Perry Homes, Poly-Tech, PHA, Protherm, Public Citizen, RAQCG, REI, Rohm and Haas, S&B, SBU Texas, Hann, TDIndustries, TAB, TxDOT, US Home, and 19 individuals made the following comments, except as noted.

The commission should eliminate the ban (operating restrictions) and replace it with an enforceable, market-based incentive program, such as California's Carl Moyer Program.

Equipment operators should have the option to use newer, more efficient equipment during all hours, which would provide long-lasting environmental benefits. Also, it would be more beneficial to require emission-controlled or electric construction equipment or fleet emission standards rather than restrict the use of existing equipment.

The commission should replace the ban with other measures that would reduce pollution from much more significant sources at much less cost to the public, such as automobiles, cleaner fuels, reducing plant expansions in the area, limiting the use of restaurant drive-through lanes, shifting school schedules to mid-September through early June, coordinating traffic lights, and implementing a four- day work week with ten-hour days.

Replace the ban with a Carl Moyers-type program.

The commission does not believe it should eliminate the operating restrictions without a quantifiable, and enforceable replacement strategy that will provide ozone reductions equivalent to those achieved by these rules. The commission believes the rules should be maintained due to the high level of NO_x emissions currently generated by non-road equipment. The NO_x emissions from non-road equipment comprise 12% of the HGA area total NO_x emissions, which is a key component in the formation of ozone. Because of the significant contribution that the equipment affected by these rules makes to the HGA area ozone levels, it is essential that the construction equipment operating restrictions rules be implemented along with the other rules and measures included in this SIP revision in order for the HGA area to demonstrate attainment with the federal ozone standard.

The commission agrees that economic incentive programs can potentially be an effective tool for achieving air quality. One such program is the Carl Moyer program in California. That program appears to be successful in providing flexibility to the regulated industry while still achieving reductions in air emissions. The California program is authorized by and funded through the state legislative process and such legislative approval does not currently exist for a similar Texas program. The commission will continue to try to identify economic incentives which it has authority to implement. Because the commission agrees that market-based incentive programs can be an important component in encouraging development of new technologies and/or greater or more cost effective emission reduction strategies, the commission has provided for the inclusion of economic incentive programs as a component of the HGA SIP in the future. Note that an exemption offered under §114.487(b) offers flexibility similar to the Carl Moyer program.

Local stakeholders in the HGA area have expressed an interest in the creation of programs designed to provide incentives for the achievement of earlier and/or greater reductions than anticipated from currently proposed control measures. Such incentive programs may be effective technology promoting tools to encourage substantial innovation and ozone reductions in the most cost-effective manner possible. Possible components of one such program could be the provision of funds on a competitive basis to entities operating both on- and non-road NO_x sources to assist in the incremental costs of acquiring cleaner equipment, which in turn could encourage earlier development of new technologies, cleaner engines, and fuels. Other incentive programs could focus on tax incentives, subsidies, research and development, technological assistance, etc. The commission anticipates that such programs could be components of the HGA ozone nonattainment SIP, either as enforceable commitments, as potential future substitute measures based on per-ton reduction cost and total funding associated with the final scope of the programs, or as alternative methods of compliance with proposed control strategies.

Allow operator option to use more efficient equipment at all times.

The commission disagrees with these comments. Even newer, more efficient equipment produces sufficient emissions to significantly contribute to elevated ozone levels. The commission does not currently have a method for establishing or implementing emissions limits for construction or industrial equipment, and is preempted by federal rules from doing so. However, establishing an effective compliance date in 2005 will afford the commission additional time and opportunity to further study and refine the existing equipment and emissions inventories and modeling to determine the feasibility of implementing emissions limits for this type of equipment, both new and old, as a way to provide operators additional flexibility in complying with these rules. The 2005 compliance date will also allow research and development to continue into alternative emissions-reducing technologies for non-road, heavy-duty diesel equipment, such as electrification, which are not currently widely available to the average equipment owner/operator. In addition, the commission has offered an exemption under §114.487(b) which will allow equipment owners/operators who do implement the use of alternate emissions-reducing technologies and/or practices that reduce emissions beyond those of new equipment, and can demonstrate equivalent emission reductions from these measures, to operate that equipment during the restricted hours. This exemption allows equipment operators to take advantage of existing and emerging alternative emissions-reducing technology which would allow those operators to use their equipment during the restricted hours if they are able to demonstrate equivalent emissions reductions. The commission does not believe it should eliminate the operating restrictions rules because of the significant contribution that non-road equipment makes to the HGA area high ozone levels. The NO_x emissions from non-road equipment comprise 12% of the HGA area total NO_x emissions. Because of the significant contribution that non-road equipment makes to the HGA area ozone levels, it is essential that the construction equipment operating restrictions rules be implemented along with the other rules and measures included in this SIP revision in order for the HGA area to demonstrate attainment with the federal ozone standard.

Replace the ban with lower cost measures directed at more significant sources.

The commission does not believe it should eliminate the construction equipment operating restrictions without a quantifiable and enforceable replacement strategy that demonstrates proven ozone reductions equivalent to those achieved by these rules. The commission also does not believe it should do away with the operating restrictions because of the significant contribution that non-road equipment makes to the HGA area high ozone levels. The NO_x emissions from non-road equipment comprise 12% of the HGA area's total NO_x emissions, a key component in the formation of ozone. Because of the significant contribution that the equipment affected by these rules makes to the HGA area ozone levels, it is essential that the construction equipment operating restrictions rules be implemented along with other rules and measures included in this SIP revision in order for the HGA area to demonstrate attainment with the federal ozone standard. The restriction on hours of operation of non-road, heavy-duty diesel equipment is an essential component to the overall strategy to reduce peak ozone levels to enable the HGA area to attain federal ozone standards. Local stakeholders in the HGA area have expressed an interest in the creation of programs designed to provide incentives for the achievement of earlier and/or greater reductions than anticipated from currently proposed control measures. Such incentive programs could be effective technology-promoting tools to encourage substantial innovation and ozone reductions in the most cost-effective manner possible. Possible components of one such program applicable to these rules could be the competitive provision of funds to entities operating both on- and non-road NO_x sources to assist in the incremental costs of acquiring cleaner equipment, which could encourage earlier development of new technologies, cleaner engines, and fuels. Other incentive programs could focus on tax incentives, subsidies, research and development, technological assistance, etc. The commission anticipates that such programs could be components of the HGA ozone nonattainment SIP, either as enforceable commitments, as potential future substitute measures based on per-ton reduction cost and total funding associated with the final scope of the programs, or as alternative methods of compliance with proposed control strategies. This SIP revision does contain a wide variety of measures to reduce pollution from the other sources mentioned in this comment. However, as explained above, the non- road equipment source category is a significant source of ozone-forming emissions, and therefore must be included in the state's efforts to reduce ozone.

One individual suggested that the operating restrictions be replaced with a program resembling a "no drive days" program, which would voluntarily restrict equipment operation only on certain days of the week, determined by the companies' geographic location or first letter of the company name.

The commission disagrees with this suggestion because EPA will not approve a voluntary measure as enforceable or quantifiable, two conditions which all approvable SIP measures must meet. In addition, the commission does not believe it should eliminate the construction equipment operating restrictions without a quantifiable and enforceable replacement strategy that demonstrates provides ozone reductions equivalent to those achieved by these rules. The commission does not believe it should eliminate the operating restrictions because of the significant contribution that non-road equipment makes to the HGA area high ozone levels. The NO_x emissions from non-road equipment comprise 12% of the HGA area's total NO_x emissions, a key component in the formation of ozone. Because of the significant contribution that non-road equipment makes to the HGA area ozone levels, it is necessary that the construction equipment operating restrictions rules be implemented along with the other rules and measures included in this SIP revision in order for the HGA area to demonstrate attainment with the federal ozone standard. The restriction on hours of operation of non-road, heavy-duty diesel construction and industrial equipment is an essential component of the overall strategy to reduce peak ozone levels to enable the HGA area to attain federal ozone standards.

PHA supports the voluntary mobile source emissions program (VMEP) as an alternative to the operating restrictions. They stated that VMEP offers the most promise for actual air emission reductions in the HGA area in terms of new technologies and preemption issues.

The commission disagrees with this comment. The construction equipment operating restrictions cannot be used as a VMEP, which is a voluntary program, because the state needs the enforceable emission reductions that the construction equipment operating restrictions rules provide in order to demonstrate attainment with the federal ozone standard.

TCC commented that provisions should be made for facilities included in the area's emissions cap and trade program to be able to include the emissions from the usage of construction and industrial equipment for maintenance and turn-arounds in the facilities' allocated cap, to enable facilities to operate affected equipment during the restricted hours.

The commission disagrees with this comment. Emissions from mobile sources and stationary sources differ in their potential to form ozone. Emissions from point sources are emitted higher into the atmosphere, while emissions from mobile sources are emitted at ground level. Therefore, these two types of emissions cannot be considered "equivalent" under the cap and trade program, prohibiting mobile source emissions from being included in a facility's allocations. However, facilities do have the option of applying for the exemption offered under §114.487(b), and if approved, would be permitted to operate their affected equipment during the restricted hours.

TCC also commented that smaller facilities not required to participate in the cap and trade program should be allowed to either voluntarily opt in to the cap and trade program to allow them to operate affected equipment during the restricted hours, or offset emissions from construction and industrial equipment used in maintenance/turn-around activities with MERCs or DERCs generated at the facility or purchased from another source in the eight-county nonattainment area as part of an emissions reduction plan.

Regarding smaller facilities or those facilities not required to participate in the cap and trade program, it is expected that the commission will add language to the rules to allow sources exempt from the cap and trade program to opt in. Regarding MERCs and DERCs, any source that reduces its emissions voluntarily and meets the requirements of the banking rules will be able to generate credits. The exemption offered in §114.487(b) gives facilities the option of offsetting emissions from heavy-duty diesel construction or industrial equipment by using credits as part of their emissions reduction plan, provided that the facility meets the requirements of the emissions banking and trading rules.

TxOGA commented that there will be little chance of oil and gas equipment operators being able to purchase emissions credits elsewhere because of the demand for such credits from other types of operations. For all practical purposes, the §114.487(b) option for an emissions reduction plan will not be available to these operators.

The commission disagrees that oil and gas operators will have difficulty purchasing emissions credits. The commission expects that as the demand for credits, and thus the price for credits, increases, the market will see a growth of applicants finding ways to generate additional credits. Also under these rules, more types of mobile sources will be able to generate credits, thus increasing their availability.

Infinity, AAA Asphalt, ARTBA, ABC, AGC-Houston, AGC-Texas, Balfour, Bearden, BFI, BorTunCo, BRC, Brown & Brown, BCCA, Casa Linda, CCC, Barker, Centex, Cherry, Simonton, Conrad, CTI, Demar, Dina, Dow, Drews, Earth Material, Reed, Ella, Emerald, ED, Excalibur, GRBirdwell, GHBA, Hassell, Higgs, Hoar, Holmes, HCIC, HCA, IEC, JBS, J&S, Frankel, Trimm, Holland, Kvaerner, Legacy, Legal Eagle, Listo, Manhattan, MB Western, MMI, Mustang Tractor, N&S, NASA, NBG, NuHome, Nunez, Paisan, Hambrick, Pate & Pate, Phillips 66, PolyTech, Protherm, Reddico, Representative Hope, Rohm and Haas, S&B, Sandlin, Slack, Sprint Sand, Hann, TDIndustries, TAB, TxDOT, TxOGA, Union Pacific, USACE, US Home, WM, and 29 individuals commented that this rule will create safety hazards, as much of the work will be done under diminished light conditions, resulting in reduced safety, increased accident rate, and increased costs to the clients. Working under lower light conditions with decreased visibility will also result in lower quality of work and will likely cause errors and material failures. Use of certain equipment, such as large cranes, cannot be performed safely at night. Increased fatigue could cause more accidents. Increased hazards will increase the cost of builders' risk and health insurance. It is dangerous to work in the heat of the day in Texas. Increased nighttime road work will result in increased motor vehicle accidents as well as increased worker fatalities in work zones.

The commission recognizes that these rules may result in increased exposure to elevated temperatures and increased fatigue and risk for accidents and injury. However, operators would be expected to take all necessary measures to protect the health and safety of their employees and educate them about potential risks. The commission does not have the capability nor authority to directly regulate worker safety. The ultimate responsibility of the commission with these rules is to maintain and improve air quality and public health for all citizens in the HGA area. Regarding the safety concerns of working in the evening hours with decreased visibility, the change to the time period between April 1 though October 31 will extend the daylight hours during the period of the year the rules will be in effect. The increased daylight hours will minimize any potential risks or quality problems associated with low visibility. In addition, the commission expects that affected companies will take necessary measures to ensure the quality of finished products, in order to retain customers and attract new business. The commission recognizes that insurance costs may increase due to the increase in activity during the late afternoon and evening hours, and that affected businesses may have to pass these costs on to their customers. However, the commission believes that companies can address customer dissatisfaction over higher costs by explaining that the cost increases were necessary to enable the company to comply with regulations that will ultimately improve the customers' air quality and health.

Demar, Reed, Hoar, Kvaerner, Manhattan, MB Western, MMI, NASA, Paisan, PolyTech, Protherm, Rohm and Haas, TDIndustries, and two individuals commented that the proposal directly violates Occupational Safety and Health Administration (OSHA) regulations.

The commission disagrees with this comment to the extent it suggests that the Commission has jurisdiction over OSHA regulations. While the commission is charged with protection of human health and the environment, this responsibility applies to external environmental matters relating to outdoor air quality, waste and water. The Commission does not have authority over issues of worker safety, especially with respect to the administration of OSHA regulations.

ARTBA, AGC-Texas, Bearden, BorTunCo, BCCA, Barker, CTI, Earth Material, Excalibur, HCIC, HCA, NBG, Pate & Pate, Reddico, and five individuals commented that the impact on the minority community is too great. Both minority workers and minority-owned businesses will be impacted disparately.

The commission maintains that the rules as adopted will not have a disparate impact on persons based on race, color, or national origin. The basis for the rules is protection of human health and the environment, and shifting the operation of construction and industrial equipment from 6:00 a.m. until noon during the ozone season is anticipated to provide reductions in the formation of ozone in the area. Although it is not clear what, if any, legal standard the commenter allege the commission would violate in adopting the rules, some state that the rules would "disproportionately impact" minorities. This is clearly a reference to Title VI of the Civil Rights Act of 1964. In order for the commission to be shown in violation of Title VI, a disproportionately negative impact to minorities must be shown; however, any potential negative impacts that may result from implementation of this rule will be borne equally by all operators of equipment governed by the rules without any differentiation by race, color, or national origin. These rules are facially neutral and apply equally to all operators of the types of equipment affected by these rules.

Infinity, AAA Asphalt, ARTBA, ABC, AGC-Houston, AGC-Texas, AAR, ASLRRA, Balfour, Bearden, Bell, BorTunCo, BRC, Brown & Brown, BCCA, Casa Linda, CCC, Barker, Centex, Cherry, La Porte, Simonton, Spring Valley, CAP, Clear Lake COC, Conrad, CTI, Dayton Pipe, Demar, Dina, Dow, Drews, Earth Material, Reed, Ella, Emerald, Excalibur, ExxonMobil, GR Birdwell, GEHC, GHBA, Harris County, Hassell, Higgs, Hoar, Holmes, HCIC, HCA, IEC, JBS, J&S, Frankel, Trimm, Holland, Kvaerner, Legacy, Legal Eagle, Listo, Manhattan, MB Western, MMI, Commissioner Metter, MSC, Mustang Trailer, N & S, NBG, NuHome, Nunez, Paisan, Hambrick, Pate & Pate, Phillips 66, PolyTech, PHA, Protherm, Reddico, Rohm and Haas, S & B, Sandlin, Slack, Hann, TDIndustries, TAB, CSE, TxDOT, TxOGA, Union Pacific, UT, US Home, Vernor, WM, and 42 individuals commented that this rule will have a detrimental impact to the Houston economy and/or its citizens' and workers' quality of life. Individuals forced to work in the evenings would no longer be able to spend that time with their families, and working parents would have limited to no daycare options. This rule will slow or halt the growth of industry and business, especially small businesses. The rule will place the region's businesses at a competitive disadvantage. The construction labor market is already suffering from shortages. Many workers would be forced to leave the industry or be unemployed to avoid working a non-traditional work day. The economic impact seems high compared to the value received.

PHA commented that according to a study conducted by Air Maritime Industry Strategy Group (AMISG), the operating restrictions will result in $178 million in additional costs related to Houston and Galveston port operations, either to the shipper through increased berthing costs or to the ports through lost business. Thousands of Texas businesses are dependent upon the Houston and Galveston ports in order to receive critical components necessary for their operations. Their inability to receive cargo for six hours each day could force them to shut down operations due to the lack of materials. This could in turn have a ripple effect through the local and state economy.

Union Pacific commented that they operate loading/unloading equipment throughout the HGA area at service and repair areas, servicing and fueling centers, classification and switch yards, and most importantly, at the Port of Houston. If products cannot be unloaded at intermodal terminals at the port for transport by rail until noon, schedules will be significantly affected, thereby affecting the flow of commerce and impacting the economy.

The commission recognizes that compliance with these rules may create short term losses in productivity, which may result in increased project duration and costs and negative economic impacts to affected businesses and the communities in which these businesses operate. However, the commission anticipates that affected companies and communities will find and make the necessary adjustments to minimize these impacts, especially considering the far more substantial economic and quality-of-life impacts that would result from the failure of the HGA area to attain the federal air quality standards that these rules are designed to help achieve. The restriction on hours of operation of non-road, heavy-duty diesel construction and industrial equipment is an essential component to the overall strategy to reduce peak ozone levels to enable the HGA area to attain federal ozone standards. Although many of the rules included in the current SIP attainment strategy may not be easy to implement and may cause many of the affected entities to have to adjust normal operations and make certain sacrifices, these rules are of critical importance in the protection of the environment and human health, which is essential for continued economic prosperity for all entities affected by the rules. Equipment owners/operators seeking relief from these rules may choose to apply for an exemption under §114.487(b). If the application is approved, the owner/operator would be allowed to continue to operate during the restricted hours. For those businesses that are unable to qualify for an exemption under the rules, or that choose not to pursue an exemption, the commission anticipates that they will develop creative solutions to continue their operations unimpeded. The commission also recognizes that these rules may cause certain disruptions to the personal and social lives of affected employees. However, the restriction on hours of operation of non-road, heavy-duty diesel construction and industrial equipment is an essential component of the overall strategy to reduce peak ozone levels to enable the HGA area to attain federal ozone standards. The area's failure to attain these standards will significantly impact the area economy, and therefore the quality of life of its citizens and communities. The restriction on hours of equipment operation prescribed by these rules is based upon well established chemistry and modeling that demonstrates that shifting morning NO_x emissions to later in the day minimizes the likelihood that those emissions will later form harmful ground level ozone.

The port and rail industries may apply for an exemption under §114.487(b) and submit an emissions reduction plan, which must demonstrate emission reductions equivalent to those that would be achieved for the port and rail industries fleets of affected equipment from implementing the construction equipment operating restrictions rules. If the port and rail industries are able to demonstrate equivalent emission reductions from alternate means, these industries would be able to operate their non-road, heavy-duty diesel construction and industrial equipment during the restricted hours, thereby reducing concerns regarding economic and quality of life impacts.

Infinity, ARTBA, AGC-Houston, AGC-Texas, Balfour, Bearden, BorTunCo, Casa Linda, CCC, Barker, Centex, La Porte, Missouri City, Simonton, Conrad, CTI, Drews, Earth Material, Ella, Emerald, Excalibur, Hassell, Higgs, Holmes, HCA, J&S, Frankel, Trimm, Holland, Legacy, Legal Eagle, N&S, NASA, NBG, NuHome, Paisan, Pate & Pate, Perry Homes, PHA, Sandlin, Slack, Hann, TAB, TxDOT, US Home, WM, and 12 individuals commented that a significant loss in construction productivity would result due to loss of morning hours when the weather is more conducive to higher productivity, and fewer hours in which to work. This loss in productivity will result in project delays, increasing project costs.

The commission recognizes that compliance with these rules may create short-term losses in productivity, which in turn may result in increased project duration and costs. However, the commission anticipates that affected companies will find and make the necessary adjustments to minimize these impacts, especially considering the far more substantial impacts that would result from the failure of the HGA area to attain federal air quality standards that these rules are designed to help achieve. The restriction on hours of equipment operation is an essential component of the overall strategy to reduce peak ozone levels to enable the HGA area to attain the federal ozone standard. Although many of the rules included in the current SIP attainment strategy will not be easy to implement and will cause many of the affected entities to adjust normal operations and make certain sacrifices, these rules are of critical importance in the protection of the environment and human health, which is essential for continued economic prosperity.

TCC commented that many plants use craftsmen for maintenance and turn-arounds whose schedules are dictated by union contracts. If regulations impose restrictions on operating equipment from 6 a.m. to noon, some plants could lose as much as half of their maintenance day.

The commission anticipates that affected facilities will conduct contract negotiations with the unions to enable union workers to complete their assigned duties on a schedule that would also allow the facilities to comply with the equipment operating restriction and maintain operations. The commission anticipates that the unions will also work with the affected facilities to resolve any scheduling issues and come to a mutually-agreeable arrangement. Additionally, facilities that obtain an exemption under §114.487(b) will be able to continue to operate during the restricted hours, thereby eliminating any need to modify union contracts.

TxDOT requested that the commission add an exemption for projects currently under contract and scheduled for completion before the rule implementation date. Without this exemption, TxDOT would have to modify all existing contracts to ensure that any projects that are not completed on schedule (by the rule implementation date) comply with the rule, although only a few projects may actually extend beyond the implementation date.

The commission does not believe that modifying existing contracts would be overly burdensome, and therefore does not agree that an exemption should be added for projects with existing contracts. TxDOT can modify its existing contracts by adding standard language that would ensure compliance with the applicable rules if the project extends past the rule implementation date.

BRC, Casa Linda, Barker, Centex, Dayton Pipe, Dow, Drews, Ella, Emerald, GHBA, Higgs, Holmes, IEC, Sandlin, TAB, TCC, TxDOT, US Home, and three individuals commented that suppliers would have to alter their delivery schedules to the evening hours, affecting their economic viability and adding to noise and pollution in the evening. Deliveries would have to be turned away because forklifts could not be operated to off-load delivered materials. The disruption in the flow of goods and services could cost millions of dollars and impede interstate commerce.

The commission disagrees with these comments. Non-diesel powered forklifts are common in many warehouses, and are not subject to the operating restrictions under these rules. Consequently, the commission believes that by 2005 affected operators will have had the time to plan for the replacement, as necessary, of their diesel-powered forklifts with non-diesel-powered models. In addition, the commission anticipates that suppliers of goods and services to companies affected by these rules may shift their hours of operation or modify their operations accordingly to retain customers and maintain their businesses. This will enable affected companies to both comply with the rules and continue to operate.

Missouri City and three individuals commented that this rule should only be in effect when weather forecasts call for high ozone, not every day, or only during the months when ozone is highest, i.e., July and August.

The commission disagrees with this comment. In order to achieve the ozone reductions necessary to demonstrate attainment with federal standards, the operating restrictions must be in place from April 1 through October 31. The risk to human health and the environment would outweigh the benefits gained by lifting the ban on days when ozone exceedances are less likely to occur, especially considering the difficulties that would exist with tracking and enforcement. The commission believes the rules must be in effect during the entire ozone season, rather than only during certain months, because conditions can be present at any time during that season for the formation of high levels of ozone.

One individual commented that this rule should be applicable statewide and not just in certain areas.

The commission disagrees with this comment. Construction and industrial equipment inventories and emission inventories do not support the implementation of these rules on a state-wide basis. These inventories and associated modeling show that the vast majority of construction and industrial equipment is located and used in the DFW and HGA metropolitan areas, coinciding with the major concentrations of population in the state. Therefore, emissions from this equipment are also concentrated in those areas. In addition, these areas have air quality problems that are more serious than the rest of the state, primarily with ozone, the compound that these rules are designed to help reduce. These existing air quality problems, coupled with the geographic concentration of equipment usage and emissions, justify implementing rules to control the emissions of ozone forming compounds from heavy-duty diesel construction and industrial equipment in the DFW and HGA areas only, rather than statewide. However, these rules do not preclude other areas considering controls on heavy-duty diesel construction and industrial equipment from implementing similar locally-regulated or voluntary programs to achieve similar benefits.

ABC, AGC-Houston, AGC-Texas, Balfour, BFI, BorTunCo, BCCA, Conrad, CTI, CWA, Dina, Earth Material, ED, Excalibur, HCA, IEC, Trimm, Holland, Listo, MCA, MCSWCD, NMA, NSWMA, NBG, Pate & Pate, Phillips 66, PHA, Montgomery County, S&B, Sierra - Houston, TCC, TxDOT, Union Pacific, WM, and 12 individuals commented that the analytical basis for the rule is flawed and should be re-analyzed. They also stated that the proposal offers no environmental benefit, the commission failed to provide adequate scientific and technical justification for the proposal, and that control measures should reduce emissions, not just shift those emissions to later in the day. The current SIP guidelines are based on inaccurate estimates of the non-road vehicle inventory. TxDOT and Sierra - Houston questioned the accuracy of the construction equipment inventory used in the modeling for the HGA area SIP.

The commission disagrees with these comments. The commission has worked extensively with the construction industry and other affected industries in the HGA area, along with consultants, to ensure that the emissions inventory and the inventory of affected equipment in the area is as accurate and as specific to the HGA area as possible. The accuracy of the inventories thereby maximizes the accuracy of the modeling of the affected industries' contribution to the air quality problem, as well as the necessary ozone reductions that this rule is designed to achieve. The commission is required to use a federally-recognized and approved model for developing data that will be used to demonstrate attainment with the SIP. The commission used state-of-the-art photochemical methodologies to develop this rule. The Comprehensive Air Model with Extensions (CAMx) model that was used is the latest version of the photochemical model recognized by the EPA for SIP modeling. Also, the Houston Diesel Construction Emissions project was conducted with the goal of improving upon the emission levels used previously in the Houston attainment plan. Previous inventories had been supplied by the EPA in their "Non-Road Equipment and Vehicle Emission Study" (NEVES, EPA-21A-2001, November 1991). As such, the accepted method to model years other than the 1990 NEVES data was to apply growth factors from the Economic Growth Assessment System (EGAS). Technology reduction factors were then applied to the grown inventories to model new federal emission rules such as those for diesel engines. Over the last year, however, a new method of calculating non-road emissions has been developed by the EPA called the NONROAD model. The NONROAD model will be used to update the attainment modeling (1993 base case and 2007 future case) for the Houston area because that model utilizes the best available science with regard to emission factors and treatment of activity (equipment usage rates) data. The NONROAD model works similar to the highway emissions model, MOBILE, in that temperatures and fuel qualities can be modified to better reflect local conditions. The main change to the NONROAD model input stream was the use of new equipment populations for diesel construction and industrial equipment. The commission worked with representative construction operators through independent engineering firms. The general approach was to define the market share of the representative construction companies and then upscale the equipment totals based upon estimated total market share. Local equipment data then had to be adjusted to state equipment populations using adjustment factors, because NONROAD requires state- wide totals to perform the county-based calculations. Under contract with the Houston-Galveston Area Council (HGAC), the Eastern Research Group (ERG) conducted a detailed survey of construction and industrial equipment populations and activity within the eight-county HGA ozone nonattainment area. As part of this effort, Starcrest Consulting facilitated communications with a coalition of local construction trade organizations and assisted with the development of survey strategies. Based on the study's findings, input files were generated for use in EPA's NONROAD emissions model in order to estimate total pollution levels from construction sources operating in the area. These results serve as an update to the commission's previous estimates based on EPA's default methodology. Commission staff then re-ran the NONROAD model using the revised input files to develop a revised construction emissions inventory for the Houston area. For several reasons it is believed that the NEVES survey methodology originally used significantly overestimated equipment populations, and therefore emissions, for the construction sector in Houston. For example, Houston serves as headquarters for some of the world's largest construction companies, with thousands of employees dedicated to engineering and administrative work. However, the employment surrogates found in the County Business Patterns Report do not distinguish between "office" and "field" employees. While the number of construction field employees in a given area may be indicative of overall construction activity, projections using total "construction employment" in the Houston area may drastically overestimate overall equipment numbers and activity. For these reasons it was thought that a "bottom-up" survey of construction and industrial sources in the area could provide significant improvements to the equipment inventory. However, previous survey attempts encountered very low response rates, and ultimately proved unsuccessful. As part of a multi-task contract with HGAC, ERG agreed to perform a comprehensive survey of all construction and industrial equipment activity in the eight-county HGA ozone nonattainment area. In order to improve survey response rates, ERG obtained assistance from a coalition of several local trade organizations, the Houston Construction Industry Coalition (HCIC). The HCIC, along with their representative Starcrest Consulting, were instrumental in identifying key experts for interviews, as well as encouraging their member companies to actively participate in the survey effort. This effort provided the commission with a much-improved inventory of construction and industrial equipment emissions in the Houston area, and resulted in the revisions incorporated into the Base 6 and Base 6a modeling. Even though the revised inventory has greatly reduced the uncertainty in construction and industrial equipment emissions, the commission continually seeks to improve its inventories. Delaying the rule effective date to 2005 will afford the commission additional time and opportunity to further address concerns with all aspects of the existing emissions inventory and modeling and make any necessary adjustments to the construction and industrial equipment inventory.

AGC-Houston commented that the ramifications of greater NO_x emissions produced throughout the evening hours are unclear for the region and bordering areas.

The commission disagrees with this comment. By shifting the emissions into the evening, the shifted NO_x will be prevented from reacting photochemically on the day of the emissions. It is typical and predictable that NO_x emissions remaining after sundown tends to disperse overnight into areas of lower emissions (usually rural), where they are less likely to lead to high ozone concentrations.

Montgomery County and MCSWCD commented that removing Montgomery County from the proposed additional air pollution measures will not make any measurable difference in the Houston ozone problem, and that eliminating Montgomery County from the construction equipment operating restrictions would result in a difference of less than 1/50th of 1% of NO_x, which is equivalent to less than 1/200th of a part per billion (0.005 ppb) of ozone. One individual commented that Chambers and Liberty Counties should not be included in this plan.

The commission continues to believe that in most cases the most effective method of achieving attainment in the HGA nonattainment area is the implementation of controls and strategies throughout the nonattainment area. Much of the HGA control strategy is based on this concept; however, 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 areas of the state. Because of this flexibility, the commission can determine which emission reduction measures are most needed and where those emission reduction measures will be the most effective in helping to demonstrate attainment. Based on estimated population, estimated population growth, and estimated emissions developed using EPA-approved methodologies, the commission concluded that the sum of the 2007 projected NO_x emissions from non-road, heavy- duty diesel construction and industrial equipment in Chambers, Liberty, and Waller Counties amounts to just under 2% of the total of those emissions in the eight-county area. The effect of shifting non-road, heavy-duty diesel construction and industrial equipment emissions in these three counties has been modeled, therefore, the commission believes that including these counties in the adopted rules will have practically no beneficial impact on peak ozone levels. This is due in part to the fact that these three counties are primarily rural in nature. The commission believes that non-road, heavy-duty diesel construction and industrial equipment emissions are more widely dispersed geographically, and are therefore unlikely to significantly influence the urban ozone plume. The commission does not, however, believe it is appropriate to exclude Montgomery County from these rules.

Based on the January 1, 2000 population estimates compiled by the Texas State Data Center, the population of Chambers County is 26,409; Waller County is 29,208; and Liberty County is 68,687; for a total of 124,304. The estimated populations of the remaining five counties in the HGA nonattainment area are: Brazoria - 236,372; Galveston - 249,898; Fort Bend - 356,555; Harris - 3,275,630; and Montgomery - 295,263; for a total of 4,413,718. The total estimated population of the entire HGA nonattainment area is 4,538,022. Thus, the population of Liberty, Chambers, and Waller Counties combined is only 2.74% of the population of the entire HGA nonattainment area.

The total NO_x emissions from all of the HGA nonattainment counties for non- road, heavy-duty diesel construction and industrial equipment is 31.54 tpd. The estimated actual NO_x emissions from non-road, heavy-duty diesel construction and industrial equipment for Liberty County is 0.22 tpd, for Chambers County is 0.21 tpd, and for Waller County is 0.19 tpd. The effect of shifting these emissions will result in equivalent NO_x emission reductions of 0.05 tpd in Liberty County, 0.04 tpd in

Chambers County, and 0.04 tpd in Waller County, for a total reduction of 0.13 tpd. These reductions together amount to less than one-half of 1% of the total of those emissions in the eight-county area. Based on this data the commission believes it is appropriate not to include Chambers, Liberty, and Waller Counties in the adopted rules.

The same is not true, however, with respect to Montgomery County, which the commission believes should be retained. Based on estimated population, estimated population growth, and estimated emissions developed using EPA-approved methodologies, the commission concluded that the sum of the 2007 projected NO_x emissions from non-road, heavy-duty diesel construction and industrial equipment in Montgomery County is just over 4% of the total of those emissions in the eight-county-area (compared to less than one-half of 1% for Chambers, Liberty, and Waller Counties combined). The effect of shifting non-road, heavy-duty diesel construction and industrial equipment emissions in this county has been modeled, therefore the commission believes that retaining Montgomery County in these rules will have a measurable and beneficial impact on peak ozone levels. Montgomery County is not primarily rural in nature, thus non-road, heavy-duty diesel construction and industrial equipment emissions are not as widely dispersed geographically as in Chambers, Liberty, and Waller Counties, and therefore are more likely to negatively influence the urban ozone plume. Based on data compiled by the Texas State Data Center, Montgomery County is the third largest county in the HGA nonattainment area with an estimated population of 295,263, or about 6.51% of the total population of the HGA nonattainment area. The county has more than twice the population of Chambers, Liberty, and Waller Counties combined. Its NO_x emissions are also significantly greater than the total of those three counties, with estimated emissions of NO_x from non-road, heavy-duty diesel construction and industrial equipment in Montgomery County equaling approximately 1.28 tpd. The shifting of these emissions is expected to result in equivalent emission reductions of 0.27 tpd of NO_x.

AAA Asphalt, ARTBA, AGC-Texas, Balfour, Brown & Brown, CWA, Demar, Reed, Hassell, Hoar, J&S, Kvaerner, Manhattan, MB Western, MMI, NSWMA, Phillips 66, PolyTech, PHA, Protherm, Rohm and Haas, S&B, TDIndustries, TxOGA, USACE, WM, and five individuals commented that this rule would result in an increased use of electricity and costs for lighting and generators, which cause pollution, as construction groups are required to work in the evening to make up for lost morning hours.

The commission disagrees with this comment. Emissions from generators, classified as "commercial equipment," are not considered to be a significant contribution to the HGA area ozone levels. While the commission recognizes that increased emissions may occur at night from artificial lighting, as well as the compensatory use of additional equipment in the afternoon, those emissions would occur well past the critical time period during which ozone-forming emissions combine to eventually form ozone. Therefore, these emissions would not cause a significant increase in peak ozone levels.

WM, BFI, and NSWMA commented that emissions will likely increase from the additional waste collection vehicles that will be required to transport waste within the reduced operating hours and that will be waiting in queue to unload. BFI commented that emissions will also likely increase from the operation of additional landfill equipment to accomplish tasks in an abbreviated time period.

The commission disagrees with these comments. While the commission recognizes that increased emissions may occur in the afternoon from the compensatory use of additional equipment in the afternoon, those emissions will occur well past the critical time period during which ozone-forming emissions combine to form ozone, and therefore are not expected to cause a significant increase in peak ozone levels.

PHA commented that implementing the construction ban for port operations will actually increase NO_x and ozone in the Houston Ship Channel rather than reduce it. The port needs to operate 24 hours a day. The ships would be forced to idle while waiting for the construction and industrial equipment to perform their needed functions on them. The backlog of idling ships will add to the NO_x emissions at the port. On average, ships require 24 to 56 hours for loading and unloading. Each ship will therefore sit idle for at least one cycle of the ban. The emissions associated with the additional idling, and the trickle-down effect on the efficiency of port operations will outweigh any ozone benefit from shifting loading/unloading equipment emissions to the afternoon and evening. Not only would the overall NO_x emissions at the port and ship channel increase, but the NO_x emissions occurring in the morning hours would also increase. According to a study conducted by the Air Maritime Industry Strategy Group (AMISG), the inability to load/unload cargo from the ships will result in an increase in morning NO_x emissions from trucks and ships. Shore-side power alternatives for vessels were researched extensively in California but found to be unfeasible.

The commission disagrees with these comments. The port could shift the hours of operation from the current 7:00 a.m. - 7:00 p.m. schedule to noon - midnight. This shift in activity would not cause the backlogs and related increase in emissions from truck idling or vessel dwell times and temporary berthing associated with trying to maintain the current schedule of operations under the equipment operating restrictions. If the port is not able to completely shift operations to after noon, the port could work with the companies representing the general cargo and container vessels to achieve a workable schedule of loading/unloading operations that also enables the port to comply with the equipment operating restrictions. The commission expects that the port can successfully work with its customers to shift its schedule of operations or coordinate scheduling to accommodate the operating restrictions, and change its business practices to ensure a decrease in emissions. The commission acknowledges that less cargo may be handled at the port because some customers will elect to take their cargo to other ports outside of the HGA area. The port may be able to qualify for an exemption under §114.487(b) of the rule. If the port is able to demonstrate equivalent emission reductions from alternate means, it would be able to continue its operations during the restricted hours, thereby reducing concerns regarding economic impacts.

ARTBA, AGC-Houston, AGC-Texas, Bearden, TxDOT, and ten individuals commented that this measure will add to endless road work and lengthen completion times. Increased pollution will result from increased congestion.

The commission disagrees with these comments. It is already common practice to perform high-volume highway construction during off-peak travel hours during the night and on weekends. Because highway construction often occurs during off-peak periods, when traffic is lighter, there should be no increase in traffic congestion. The commission expects that entities performing highway construction will modify their schedules to minimize any project delays associated with these rules.

TxDOT, Houston District, stated that they have contractual restrictions on highway lane closures during peak traffic hours (typically 7:00 a.m. - 9:00 a.m. and 3:00 p.m. - 5:00 p.m.), and some contracts require operations to cease by sunset. These TxDOT restrictions, coupled with these rule restrictions, would severely limit the time available to perform road construction.

The commission expects that any contractual conflicts will be resolved in the common interest of achieving the federal ozone standard. If this standard is not achieved, the federal government could withhold funding for highway repairs and construction, which represents a much greater impact on the completion of road construction projects than the equipment operating restrictions.

AGC-Houston, AGC-Texas, BRC, Centex, Cherry, GHBA, Holland, N&S, Phillips 66, Reddico, TxOGA, and three individuals commented that noise pollution in residential areas in the evenings would be a problem, and that there are restrictions against such "after hours" activity in most municipalities.

The commission acknowledges this comment and that equipment operators may desire to work later hours to compensate for time lost in the early morning. If this is true, communities may wish to reevaluate their current ordinances and determine what is best for their community. Because maintaining and improving air quality, for which these rules are designed, is vital to the health and welfare of all the citizens in the HGA area, local entities have a vested interest in taking measures necessary to enable compliance with the rules.

AGC-Texas, BFI, BorTunCo, Casa Linda, Centex, CAP, Conrad, CTI, Dina, Drews, Earth Material, Ella, Emerald, ED, Excalibur, Harris County, Higgs, Holmes, HCA, Liberty County, NBG, Pate & Pate, Public Citizen, Sandlin, Sierra - Houston, Sprint Sand, TAB, US Home, and 14 individuals commented that this rule will be unenforceable, especially considering the number of employers using the affected types of equipment in the HGA area. Enforcement would most likely trickle down to local government, which does not have funding or manpower to handle this responsibility. One consequence would be no uniformity of enforcement.

The commission disagrees with these comments. Enforcement of the rules will be achieved in two ways: 1) on-site inspections, and 2) facility records reviews. The commission anticipates that the primary method of enforcement will be through records reviews. Additionally, compliance will be determined by on-site investigations, both routinely scheduled and in response to complaints. The commission will work with local officials to ensure enforcement of the SIP and SIP rules. The commission has existing relationships with pollution control authorities in the City of Houston, Harris County, and Galveston County for enforcement of other commission rules. The commission will continue to work closely with local entities in a cooperative effort to maximize its compliance and enforcement efforts.

AAR, ASLRRA, La Porte, CWA, Dow, Enterprise, Kinder Morgan, Lyondell-Citgo, Pasadena/Donohue, Phillips 66, PHA, Rhodia, TCC, Union Carbide, Union Pacific, and two individuals commented that the restrictions would limit businesses' ability to efficiently perform maintenance operations, and industrial processing operations, efficiently complete planned unit outages (turnarounds), and operate safely. Equipment used for these purposes, such as front-end loaders and forklifts, should be exempt - specifically, ". . . equipment used in a manufacturing process as part of normal operations; equipment used in manufacturing, production, shipping, and receiving activities; equipment used for routine or scheduled maintenance and/or construction activities at manufacturing facilities; and equipment used in the moving of materials at a manufacturing plant."

PHA commented that the commission should consider an exemption for port loading/unloading equipment based on the NO_x emissions increase (both overall and in the morning hours) and the economic factors discussed in previous comments. Specifically, PHA requested that §114.487(a) be revised to add the following clause: "3) Equipment used for cargo handling (including but not limited to loading and unloading) at a port or marine terminal facility."

Pasadena/Donohue commented that without the ability to use front-end loaders, pulping operations at paper mills would not be able to operate during the restricted hours, as well as recycled paper repulping operations, effectively shutting down the entire paper recycling mill.

TCC, TxOGA, and Phillips 66 commented that there are many pieces of heavy equipment at refineries, petrochemical plants, oil production facilities, pipeline operations and terminals, which are used for maintenance and on-going production or operation. The rule must clarify for operators that this is not "construction equipment" and that these should be specifically exempt from the requirements of §114.482.

The commission acknowledges that the operating restrictions could impact industrial maintenance and process operations for affected entities throughout the HGA area. However, the types of diesel equipment used for these purposes are considered "industrial equipment," and are subject to this rule in the same way and for the same reasons as construction equipment. Diesel-powered industrial maintenance and process operation equipment are significant contributors to high ozone levels in the HGA area. It is therefore important to restrict the use of this equipment, along with construction equipment, in order to reduce ozone levels in the HGA area, and to enable the area to attain the federal ozone standard. The commission does not believe it can exempt this equipment from the rules and still meet the federal ozone NAAQS. However, much of the equipment used for industrial maintenance and process operations, such as forklifts, is already powered by propane engines, or other types of engines not subject to these rules. Facilities using such alternative equipment would not be restricted from operating during the restricted hours. Also, facilities can shift their schedules for routine maintenance and planned unit outages to accommodate the restriction on equipment operation during the morning hours. The commission anticipates that facilities which operate continuously will modify their operations to enable them to comply with the rules while minimizing any potential disruptions in operations and production. Furthermore, facilities that qualify for an exemption under §114.487(b) would be able to continue to operate during the restricted hours. Equipment used at refineries, petrochemical plants, oil production facilities, pipeline operations and terminals for maintenance and production or operation is also considered "industrial equipment," subject to these rules.

Phillips 66 and TxOGA recommended adding the following language in §114.487, Exemptions: In paragraph (a) add: "3) equipment used exclusively in the exploration, production, processing, or transportation of crude oil, condensate, or petroleum products."

TxOGA and Houff commented that it would not be possible to maintain the levels of oil and gas production, transportation, processing, and manufacture of refined products to meet the nation's energy needs if the six-hour ban on startup and operation of non-road diesel equipment is applied to heavy equipment used "within the process" or for ongoing maintenance of operating units at these facilities. For example, drilling operations are typically 24-hour-a-day operations, and shutdowns will endanger the wellbore. In addition, sustaining oil and gas well production requires that wells periodically be pulled for subsurface equipment repair; such operations need to be performed when problems occur and cannot be deferred to the winter months without a loss in production.

The commission acknowledges that the operating restrictions could impact the oil and gas industry throughout the HGA area. However, because of their significant contribution to high ozone levels in the HGA area, equipment used at refineries, petrochemical plants, oil production facilities, pipeline operations, and terminals for maintenance and production or operation are considered "industrial equipment," subject to the operating restrictions in the rule. It is necessary to restrict the use of industrial equipment in order to reduce ozone levels in the HGA area. The commission expects that oil and gas facilities can schedule their operations and maintenance to accommodate the restriction on equipment operation during the morning hours while maintaining adequate production. The commission anticipates that facilities which operate continuously will modify their operations to enable them to comply with the rules while minimizing any potential disruptions in operations and production. Additionally, oil and gas facilities have the option of applying for an exemption under §114.487(b) which, if approved, could allow them to continue operations during the restricted hours.

TXI commented that the 6:00 a.m. to noon ban on the operation of non-road diesel construction equipment will make it very difficult, if not impossible, to mine and stockpile sufficient clay for the year-round operation of lightweight aggregate kilns. Furthermore, the ban would disrupt the loading of product to customers such as ready-mix concrete companies. The clay can only be mined during the relatively dry part of the year, which coincides with the time period of the equipment ban. TXI requested that the commission revise the proposed equipment operation ban to alleviate hardships that will result to lightweight aggregate kiln operators and other businesses. TXI also requested that the commission exempt lightweight aggregate kiln operators from this rule who can demonstrate that it is necessary to their business activities to operate the affected equipment during the equipment ban period. Alternatively, TXI suggested that the commission revise the ban to restrict its applicability to a narrower range of equipment, thereby lessening the hardship that will result from the rule.

The commission disagrees with these comments. The commission believes that the lightweight aggregate kiln industry will be able to shift daily mining schedules to the afternoon and evening to accommodate the restriction on equipment operation during the morning hours. The commission anticipates that facilities will modify their operations to enable them to comply with the rules while minimizing any potential disruptions in operations and production. Also, facilities that meet the exemption offered in §114.487(b) would be able to continue to operate during the restricted hours. The commission recognizes that compliance with these rules may cause some scheduling and logistical difficulties. However, the commission expects that affected companies will be able to find and make the necessary adjustments to minimize these impacts, especially considering the far more substantial impacts that would result from the failure of the HGA area to attain federal air quality standards. The restriction on the hours of operation of construction and industrial equipment is an essential component of the overall strategy to reduce peak ozone levels in the HGA. Therefore, the commission does not believe it should exclude the lightweight aggregate kiln industry from these rules. It is important that all affected industries that contribute significantly to the elevated ozone levels in the HGA nonattainment area participate equally in the prevention and reduction of those levels of ozone. The commission does not believe it should reduce the applicability of the rules to cover less equipment, because it is essential to include all construction and industrial equipment in the operating restrictions in order to achieve adequate ozone reductions to enable the HGA area to attain the ozone standard. Although some of the rules included in the current SIP attainment strategy may present some short-term implementation difficulties, and may even require certain long-term operational adjustments, the commission believes that these changes are necessary for the protection of human health and the environment in the HGA area, and are an indispensable part of the effort to achieve attainment of the federal ozone NAAQS.

WM, NSWMA, and BFI commented that equipment used at solid waste management facilities should be exempted for the following reasons. 1) Public safety will be impacted because waste collection vehicles will be forced to pick up trash in the early evenings when more residents are home and children are playing on streets in area neighborhoods, and odor and vector problems could arise from waste accumulating at homes and businesses. 2) Spotters' ability to identify unacceptable hazardous waste at landfills will be hampered without the use of spreading equipment. 3) The inability to compact waste during the busiest hours of operation will significantly decrease the density of waste and lead to a more rapid consumption of landfill capacity, decreased landfill stability, increased settling, and increased risk of cap and liner failure. 4) Accumulated waste at the landfill working face or tipping floor will make it difficult to control odors, windblown trash, birds, rodents, flies, and potentially the spread of disease. 5) Limited operational capacity at landfills may result in increased disposal at unregulated facilities. 6) Costs of landfill development will increase as work would have to occur outside of normal business hours.

Public safety will be impacted.

The commission disagrees with this comment. These rules do not restrict the hours of operation of waste collection vehicles, as these are on-road vehicles, and the rules apply only to non-road equipment. For those facilities that elect to delay waste collection, the commission expects that they will take the necessary steps to ensure the safety of customers, such as informing residents in advance of operational changes by such methods as distributing notices to customers alerting them to changing hours of operation. The commission recognizes that facilities may elect to delay collection activities to limit waste accumulation at landfills, and that solid waste placed at curbside may sit for longer periods of time before collection. However, the commission disagrees that a collection delay will necessarily result in additional odor, litter, and vector problems as collection delays should be minimal. In addition, waste disposal companies could eliminate problems associated with waste accumulation at homes and businesses by informing customers of scheduling changes and of the need to delay setting out their waste for collection. In addition, waste management facilities have the option of applying for an exemption under §114.487(b) which, if approved, would allow operations during the restricted hours, thereby eliminating any need to modify waste collection schedules.

Spotters' inability to identify their waste.

The commission disagrees with this comment. The commission expects that facilities will develop alternative procedures to ensure the effective identification of unacceptable wastes. In addition, facilities will have the option of applying for an exemption under §114.487(b) which, if approved, would allow continued operations during the restricted hours, thereby reducing any potential problems associated with the need to use spreading equipment.

Inability to compact waste.

The commission disagrees with this comment. Facilities can minimize many of these potential problems by making scheduling, design, and operational. As stated above, facilities will have the option of applying for an exemption under §114.487(b) which, if approved, would allow continued operations during the restricted hours, thereby reducing any potential problems associated with the need to compact waste.

Unacceptable accumulations of waste: orders, vector attraction

The commission disagrees with this comment. Although waste may be accepted during the period during which the affected equipment is restricted from operating, the commission assumes landfill operators will appropriately cover the working face of their landfills in accordance with all permit and rule requirements, including those in 30 TAC §330.115, Fire Protection; §330.117, Unloading of Waste; §330.129, Control of Windblown Waste; §330.125, Air Criteria; §330.126, Disease and Vector Control; §330.132, Compaction; §330.133, Landfill Cover; and §330.136, Disposal of Special Wastes. Facilities can minimize any potential impacts of the rules through design and operational changes, including additional road and working face lighting, traffic control, segregation of commercial and private vehicle disposal areas, and use of personnel to specify dumping locations. The commission expects that waste disposal facilities will make the necessary scheduling, design, and operational changes to minimize these potential problems, and avoid permit violations. In addition, facilities will have the option of applying for an exemption under §114.487(b) which, if approved, would allow continued operation during the restricted hours, thereby eliminating any potential problems associated with the need to process waste during morning collection hours.

Limited operational capacity at landfills.

The commission disagrees with this comment and believes that professional waste haulers are unlikely to divert their loads to "unregulated facilities." The commission also does not believe that any potential shift in operations under these rules will negatively affect the ability of individuals to legally dispose of their trash at regulated facilities. In addition, facilities will have the option of applying for an exemption under §114.487(b) which, if approved, would allow continued operation during the restricted hours, thereby reducing any potential problems associated with any limited operational capacity, and illegal disposal at unregulated facilities.

Landfill development costs increase.

The commission disagrees with this comment. The commission expects that affected facilities will develop strategies to accommodate any shift in business hours, in order to perform required functions to ensure that the facilities continue to operate according to permit conditions, while complying with the restriction on equipment use. In addition, facilities will have the option of applying for an exemption under §114.487(b) which, if approved, would allow continued operations during the restricted hours, thereby reducing any potential problems associated with the costs of landfill development.

NSWMA commented that by not processing the accumulated exposed waste in a timely manner, there could be an increase in the atmospheric release of VOCs from the waste, which reduces the air emission benefits from not operating the equipment.

The commission disagrees with this comment. The operating restrictions, while offering some shifting of VOC emissions, are primarily a NO_x-shifting strategy. The commission expects that waste disposal facilities will make the necessary scheduling, design, and operational changes to minimize any potential problems from the inability to process waste. In addition, facilities have the option of applying for the exemption offered under §114.487(b), and if approved, would be permitted to operate their affected equipment during the restricted hours, eliminating any potential problems associated with the inability to process waste.

NSWMA also commented that the time a solid waste facility accepts waste cannot be extended in most cases because: 1) a facility's permit may limit the hours of operation to sometime in the afternoon or early evening; and 2) many contracts require the transporter to collect the waste at certain times, typically between the hours of 7:00 a.m. and 7:00 p.m.

The commission disagrees with comment 1). The commission recognizes that operators of permitted MSW facilities may find that conditions have changed such that operating hours and procedures specified in the approved facility permit (including the Site Operating Plan) need to be revised. Changes to operating hours of less than one hour beyond the hours specified in the approved facility permit are considered non-substantive changes and are processed by the commission MSW Permits Section as Class I permit modifications. Changes to operating hours of more than one hour beyond the hours specified in the approved facility permit are considered substantive changes and are processed by the MSW Permits Section as minor or major amendments, depending upon the length of extension requested. Changes to operating hours that extend the hours by more than one hour, but less than two hours are processed by the MSW Permits Section as minor permit amendments and changes of more than two hours are processed as major permit amendments. Changes to non-substantive permit terms and procedures are processed by the commission MSW Permits Section as Class I modifications under 30 TAC §305.70, Recordkeeping Class I Modifications, while changes to substantive terms are processed as a minor or major permit amendment under 30 TAC §305.62, Amendments. The commission believes that the commission MSW Permits Section has adequate staff and resources to process amendment or modification requests, that would result from implementation of these rules, within required processing time frames. Facilities that are contractually obligated to collect waste between 7:00 a.m. and 7:00 p.m may need to increase the number of collection vehicles to collect the same volume of waste in the compressed time period. The commission expects that these facilities will develop a method to comply with both their contracts and the equipment operating restrictions.

The commission also disagrees with comment 2). The construction equipment operating restrictions rules do not directly affect the operational hours of the waste collection and transporter equipment, as this equipment is on-road, and the rules only apply to non-road, heavy-duty diesel equipment; therefore, contracts with waste collectors/transporters would not be impacted. The commission also notes that because the effective date of these rules is not until 2005, facilities should have sufficient time to work out any desired changes to existing, new, or renewed contract terms and conditions. Facilities will have the option of applying for an exemption under §114.487(b) which, if approved, would allow continued operations during the restricted hours, thereby reducing any potential problems associated with permitting or waste collection.

TFA and TLC commented that if the operating restrictions apply to timber harvesting equipment, harvesting operations would be shut down and serious restrictions would be placed on the ability to deliver logs from the woods to the processing mills. Timber harvesting and transportation equipment should be exempted from these restrictions.

Equipment used to transport harvested timber is not affected by the construction equipment operating restrictions rules because it is on-road equipment. The construction equipment operating restrictions rules only apply to non-road, heavy-duty diesel equipment. Therefore, the operation of transportation equipment would not be restricted. Equipment such as chainsaws, shredders, fellers, bunchers, and skidders used in the timber industry are classified as "logging equipment" and are not subject to the equipment operating restrictions. However, equipment such as loaders, (including skid steer loaders used with sheer heads) and bulldozers are classified as "construction equipment" and are subject to the operating restrictions. It is necessary to restrict the use of construction and industrial equipment from all affected industry sectors in order to reduce ozone levels in the HGA. Accordingly, the commission does not believe it should exclude this type of equipment from these rules. Companies can shift their operating schedules to accommodate the restriction on equipment operation during the morning hours. Companies can also modify their operations to minimize losses in productivity by utilizing equipment not affected by the operating restrictions to perform necessary operations, or by using artificial lighting to enable work to continue into the evening hours. Also, companies that obtain an exemption under §114.487(b) would be able to continue their operations during the restricted hours. The commission recognizes that compliance with these rules may cause short-term losses in productivity. However, the commission anticipates that affected companies will make the necessary adjustments to minimize these impacts, especially considering the far more substantial impacts that would result from the failure of the HGA area to attain federal air quality standards that these rules are designed to help achieve. The restriction on hours of operation is an essential component of the overall strategy to reduce peak ozone levels in the HGA Although some of the rules included in the current SIP attainment strategy may present some short-term implementation difficulties, and may even require certain long term operational adjustments, the commission believes that these changes are necessary for the protection of human health and the environment in the HGA area, and are an indispensable part of the effort to achieve attainment of the federal ozone NAAQS.

Kossman commented that implementation of the operating restrictions would have devastating results in their attempts to follow stringent federal guidelines pertaining to sowing grass seed and planting sod for erosion control, as those operations must be performed during the first few hours of the day after daybreak.

The commission disagrees with this comment. Equipment used in erosion control reseeding and sodding operations, such as tractors and hydroseeders, are classified as "agricultural equipment," and therefore are not subject to the equipment operating restrictions.

Union Carbide commented that air compressors and portable electric generators are used to provide fresh air and lighting for confined space work. When work is not occurring, it is often necessary to keep air compressors working to keep a fresh air supply going into the confined spaces. Moving the work schedule to start at noon means that real work may not begin until much later if the confined space has heated significantly from the sun.

TCC commented that the commission should clarify that, for purposes of the construction equipment operating restrictions requirements, "utility equipment," such as air compressors and welding machines, is not included in "construction equipment." In addition, the commission should clarify that the rule is not intended to regulate ship on-board diesel pumps or on-board diesel generators at chemical plant docks.

One individual commented that his company wouldn't be able to use their air compressors, water pumps, and welding machines.

The commission concurs with these comments. Equipment items such as air compressors, welding machines, pumps, and generators are classified as "commercial" equipment and are not subject to the operating restrictions. This rule applies only to construction and industrial equipment. The commission has clarified the types of equipment that are affected by the rules by listing construction and industrial equipment types in the rule preamble.

The Galveston office of the USACE commented that these rules would have a devastating impact on deep and shallow draft navigation in the HGA area, and increase ship channel maintenance dredging costs. The impact is due to the dredges being precluded from beginning operation until the backlog of ship traffic that was not able to operate from 6:00 a.m. to noon clears.

The commission disagrees with this comment. The construction equipment operating restrictions rules do not apply to marine vessels. This rule is applicable only to non-road, heavy-duty diesel construction and industrial equipment with engines rated at 50 hp and greater. The marine activity the individual describes would will not be impacted by this rule, nor will the activity of the dredging equipment as it relates to the deep draft vessel operation. However, dredging equipment would still be subject to the rule's time of day operating restrictions to the extent that equipment qualifies as "construction" or "industrial equipment."

Chambers County and two individuals commented that diesel restrictions would affect farmers in the Chambers County area very unfavorably.

The commission disagrees with this comment. The construction equipment operating restrictions rules do not apply to agricultural equipment. Therefore, the operating restrictions would not affect farmers unless they were using construction or industrial equipment which is subject to the rules. In any event the commission decided, for the reasons previously discussed, not to include Chambers County in the adopted rules.

Dow, Rhodia, TCC, and Union Carbide commented that equipment used for "emergency operations" should be exempted, and "emergency" should be redefined in the rule as "any operation necessary to protect public health, welfare, or the environment, to ensure continued safe operations." Kinder Morgan requested that the commission provide an exemption from the operating restrictions for activities required in emergency situations, including emergency repairs to gas pipeline facilities. AAR, ASLRRA, and Union Pacific commented that railroad signal failures need to be fixed immediately or accidents could occur. Safety concerns could also arise from the railroad's inability to conduct rail/right-of-way maintenance activities and loading/unloading activities. La Porte commented that the proposed emergency exemption is vague, and interprets it as being restricted to life-threatening emergencies. This definition would exclude maintenance and repair of essential city services and infrastructure, all of which are regulated by the commission and the EPA. This definition would prohibit the maintenance and repair of major water leaks, sewer stoppages, water distribution and wastewater collection systems, wastewater treatment, street repair and construction, and storm water system maintenance and construction, some of which would place La Porte in direct violation of permits and regulations administered by the commission and the EPA. La Porte suggested that the definition of "emergency" be clarified to include "maintenance and repairs of essential public infrastructure that protects the health, safety, and welfare of the public." Enterprise commented that this proposal would jeopardize safety by hindering a company's ability to respond to upsets and other occurrences that, while not emergencies in and of themselves, could develop into emergencies if not promptly addressed.

The commission concurs with these comments, and revised the rule language of the current exemption in §114.487(a)(1) to include: "equipment being used for emergency operations to protect public health and safety or the environment, including equipment being used to repair facilities, devices, systems, or infrastructure that have failed or are in danger of failing in order to prevent immediate harm to public health, safety, or the environment." For purposes of this section, the term "public" includes employees at affected entities. It should be noted that the exemption in §114.487(a)(1) does not cover equipment being used for routine maintenance of facilities, devices, systems, or infrastructure, as those activities are not of an emergency nature and are not essential to preventing immediate harm to public health, safety, or the environment. The commission expects that affected entities will adjust maintenance schedules accordingly or modify operations to accommodate the operating restrictions, while ensuring the continued safety of the public and the environment. The commission anticipates that public entities can resolve any issues regarding conflicts with commission permits or regulations relating to maintenance of infrastructure. Also, facilities that are able to obtain an exemption for routine maintenance activities under §114.487(b) will still be able, during the restricted hours, to continue to perform those activities.

TGC, GPA, and Kinder Morgan fully supported the exemption contained in §114.487(a)(1) for the protection of public health and safety or the environment. While not explicitly stated, these entities believe that emergency pipeline repairs are covered by this exemption due to the public need and necessity of the transmitted gas. If this assumption is incorrect, these entities respectfully requested clarification of this point. TxDOT also supported the exemption for emergency operations, as well as the exemption for wet concrete operations.

The commission agrees in part and disagrees in part with the commenter's interpretation of the rule with respect to emergency pipeline repairs. Emergency pipeline repairs are covered under this exemption, not because of the public need of the transmitted gas, but because of the potential danger to human health and the environment from a damaged or malfunctioning pipeline. The commission acknowledges TxDOT's support of the exemption for emergency and wet concrete operations.

Phillips 66, TxOGA, and one individual commented that the definition of "construction equipment" needs to be clarified.

The commission agrees with the commenter and wishes to clarify that both construction and industrial equipment are subject to the rules. The commission has therefore included the term "industrial" in the preamble and rules in each instance where the type of equipment affected is mentioned, and has also added to the preamble a list of the specific types of equipment included in the categories "construction and industrial equipment" that are subject to these rules.

One individual commented that the emissions reduction plan exemption should include a broad number of options, not just related to the heavy equipment itself.

The commission disagrees that the exemption does not allow for a broad range of possibilities. The emissions reduction plan exemption does not restrict what strategies are available to the requestor so long as those strategies are quantifiable and have demonstrable and constant emission reductions. Equipment owners/ operators are encouraged to pursue options such as employee trip reduction measures and other related measures to meet their necessary emission reductions.

Chevron, Phillips 66, PHA, TCC, TxOGA, and one individual commented that the commission should change the submission date for the emissions reduction plan to one year prior to the rule compliance date, rather than three years prior. Phillips 66 and TxOGA commented that the requirement to submit the emissions reduction plan three years prior to the compliance date is unreasonable, because the type and amount of equipment in use could change dramatically in that time frame and significant rework will be required. The requirement should be shortened to approximately six months (or one year maximum) prior to the compliance deadline.

The commission disagrees with this comment. The commission is requiring submission of the emissions reduction plans three years prior to the compliance date to allow adequate time for review of the plans, both by the commission and the EPA, and to allow the commission to ensure that the collective emission reductions achieved by the plans are equivalent to the ozone reductions achieved by implementation of the rules. This determination will require time-consuming modeling work, which requires that the plans be submitted as far in advance of the compliance date as was established in the rules. Regarding the concern about changes in equipment fleets during the time between submission of the plans and the compliance date, the calculations in the plans will actually be based on the owner/operator's best estimate of their fleet as it exists on the rule implementation date, April 1, 2005. Therefore, any changes that occur to equipment fleets before that date will not affect the calculations used to determine an owner/operator's exemption status.

Phillips 66 and TXOGA also commented that the guidance document mentioned in the proposal should be available 12 months prior to the emissions reduction plan submission date.

The commission agrees with this comment. The guidance document will be available May 31, 2001 to aid owners/operators in preparing their emissions reduction plans. The guidance document will outline requirements for the emissions reduction plan exemption in detail. A working draft is currently available, and the commission is accepting comments from all interested parties on the draft guidance document through May 1, 2001. The commission is also holding workshops for all interested parties to give input into the development of the guidance document, to help develop a useful guidance document and a workable approach for meeting the exemption, and to ensure that the final document is as useful and helpful as possible in enabling all entities interested in pursuing an exemption to successfully doing so.

Chevron requested clarification of the criteria and standards that will be applied in demonstrating to the executive director an alternative, equivalent emissions reducing measure under §114.487(b). Phillips 66 and TxOGA commented that the requirements for meeting the alternative emissions reduction plan exemption need to be outlined within the rule.

The guidance document that will be available May 31, 2001 will outline requirements for the emissions reduction plan exemption in detail. The commission does not believe that it is necessary to amend the rule itself, since this guidance document will thoroughly outline the requirements for an emissions reduction plan exemption. A working draft is currently available, and the commission is accepting comments from all interested parties on the draft.

Phillips 66 and TxOGA commented that a quantification of NO_x reductions are required since the claims of ozone reduction by this rule are not easily quantified at the equipment or site level.

Commission modelers have calculated the equivalent reductions in NO_x emissions from shifting NO_x emissions attributable to non-road, heavy-duty diesel construction and industrial equipment from morning until after noon. For the HGA area, NO_x emissions from non-road, heavy-duty diesel construction and industrial equipment comprise 3.3 % of the area's total NO_x emissions. Implementation of the construction equipment operating restrictions rules would result in a shift of 7.9 tpd in NO_x emissions. This shift in NO_x emissions is equivalent to a 6.7 tpd reduction in NO_x. The guidance document scheduled to be released by May 31, 2001 will provide instructions on how equipment owners/operators can calculate ozone reductions needed to qualify for the exemption for their individual fleet of equipment.

TxDOT commented that they appreciate the exemption offered for emissions offsets, but have concerns about the feasibility of obtaining these reductions. TxDOT's review of the attainment demonstration and rule packages indicated that the 6.7 tpd NO_x equivalent in the construction shift rule represents a 37% reduction above the Tier 2/Tier 3 and fuel credits. TxDOT's interpretation of the emission offset exemption is that construction equipment can continue to operate if NO_x emissions can be reduced 37% above the reductions obtained from fuels, diesel emulsions, and Tier 2/Tier 3 equipment. TxDOT requested clarification on the validity of those assumptions.

The 37% reduction estimate obtained by TxDOT represents the reductions expected to be achieved for the fleet of construction and industrial equipment for the entire HGA area. In order for an individual entity such as TxDOT to meet the emissions reduction plan exemption, the plan must demonstrate reductions in NO_x emissions equivalent to the reductions that would result from the implementation of either or both rules on their individual fleet of equipment. Therefore, the reductions required for an individual fleet should only be a fraction of the 37% of the total reductions. The procedure for quantifying the required fleet emission reductions under the emissions reduction plan exemption will be further explained and clarified in the guidance document that the commission is preparing. The guidance document will be available on May 31, 2001 to aid owners/operators in preparing their emissions reduction plans. A working draft is currently available from the commission, and the commission is accepting comments from all interested parties on the draft guidance document. The commission is also holding workshops for all interested parties to give input into the development of the guidance document, to help develop a useful guidance document and a workable approach for meeting the exemption, and ensure that the final document is as useful and helpful as possible in enabling all entities interested in pursuing the exemption in successfully doing so.

TxOGA commented that most oil and gas operators in the HGA area, simply because their operations do not generate large volumes of NO_x, will not have the ability to make offsetting NO_x emission reductions elsewhere in their operations.

The commission disagrees with this comment. The commission intends to work cooperatively with all affected entities, large and small, that wish to pursue the emissions reduction plan exemption, to give them equal ability to utilize the exemption. The commission is developing a guidance document that will be available May 31, 2001 to aid owners/operators in preparing their emissions reduction plans. The guidance document will outline requirements for the emissions reduction plan exemption in detail. A working draft is currently available from the commission, and the commission is accepting comments from all interested parties on the draft guidance document. The commission is also holding workshops for all interested parties to give input into the development of the guidance document, to help develop a useful guidance document and a workable approach for meeting the exemption, and ensure that the final document is as useful and helpful as possible in enabling all entities interested in pursuing the exemption in successfully doing so.

Phillips 66 and TxOGA commented that the requirement in §114.487(b) to demonstrate NO_x reductions equivalent to those required by §114.472 as well as §114.482 is not justified, because an owner/operator's equipment may not be subject to both rules; therefore, the owner/operator should not be required to demonstrate emission reductions for a rule to which he or she is not subject. If the requirement is intended to exempt the equipment from §114.472 as well as §114.482, the rules need to be revised to do so.

The preamble to the construction equipment operating restrictions rules for the HGA area clarifies that the emissions reduction plan must describe in detail how the operator will modify behavior or fleet of equipment to reduce NO_x emissions by the implementation date in 2005 by a target amount equivalent to the reductions that would result from the implementation of either or both rules on their individual fleet of equipment. Owners or operators may apply for an exemption from either the construction equipment operating restrictions rules or the accelerated purchase of non-road, heavy-duty diesel equipment rules, or from both sets of rules. The commission has also revised §114.487(b) of the rule as follows to clarify that equipment owners/operators may apply for exemption from either one or both rules: "Operators that submit an emissions reduction plan by May 31, 2002, which is approved by the executive director and the EPA no later than May 31, 2003, will be exempt from operating hour restrictions upon implementation of these rules in 2005, and will be permitted to operate during the restricted hours. The executive director may allow plans to be submitted after May 31, 2002. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division. In order to be approved, the plan must demonstrate NO_x reductions equivalent to those which would otherwise have been required under the rules, and must also contain adequate enforcement provisions. The operators may submit a plan for exemption from the control requirements of §114.472 of this title (relating to Control Requirements), §114.482 of this title, or both."

PHA commented that EPA approval of an emissions reduction plan should not be necessary. The commission has the requisite authority to approve the plans and should not require EPA approval. Therefore, PHA requested that §114.487(b) be revised to delete the phrase "and the EPA" with regard to approval of the plans.

The commission disagrees with this comment. The EPA review of the emissions reduction plans is required to ensure that the SIP is complete, approvable, and enforceable.

Dow and TCC suggested that the commission delete the requirement for maintaining daily operating records including equipment start and end times, as this requirement is overly burdensome with no environmental benefit. The commission should consider alternate measures to document compliance such as requiring operator training, or posting of allowable usage on the equipment.

The commission disagrees with this comment. The information needed for the operating records can be easily recorded and assembled. Additionally, the records retention requirement should not be overly burdensome. In addition, companies that obtain an exemption under §114.487(b) will need to maintain records to demonstrate compliance with the terms of the exemption. The name of the equipment operator is required because it gives the agency with jurisdiction to review the records the necessary witness link to verify the authenticity of the records during a records review. The commission believes it is necessary to require the recording of the hours of operation of each piece of equipment to enable the air pollution program with enforcement jurisdiction the ability to determine a company's compliance with the rules. The commission expects that affected entities will develop procedures suitable to their specific operations that will make this recordkeeping as workable as possible.

TCC commented that the commission should revise §114.486(b) as follows: ". . . any records required to be maintained in accordance with this section within 5 *working* days of a written request . . .." The TCC stated that companies should be given five working days to complete a request.

The commission agrees with this comment, and has revised the rule to incorporate the suggested change.

TGC commented that the commission should allow exemptions on a case-by-case basis for those sources that conduct the majority of their ozone-precursor forming operations outside of the ozone season. These primarily "winter-operated" facilities could only be allowed to operate during the restricted period by purchasing allowance credits from other sources.

The commission disagrees with this comment. The construction equipment operating restrictions rules do not restrict the operation of heavy-duty diesel construction and industrial equipment from November through March. Although certain facilities conduct the bulk of their business operations during the months outside of the "ozone season," some of their operations are nonetheless conducted during the ozone season months. These operations, to the extent they involve non-road, heavy-duty diesel construction or industrial equipment, still generate ozone-forming NO_x emissions. The commission cannot, therefore, use the TGC argument as a valid basis for exempting their construction and industrial equipment operations. However, TGC has the option of applying for an exemption under §114.487(b) which, if approved, would allow operations during the restricted hours of the "ozone season."

TxOGA commented that the rule should allow flexibility such that heavy equipment usage for actual "construction of new facilities" could be included in the new source review planning for the facility during permitting. Facilities could opt to construct during non-ozone season periods or offset the required emission reductions for the construction period by using DERCs to utilize a proposed alternative reduction at the plant site, either via curtailment of a source or reduction within the heavy equipment inventory at the site.

This rule does not restrict the operation of heavy-duty diesel construction and industrial equipment from November through March. Furthermore, under §114.487(b), a facility could be able to use DERCs as an alternate strategy for an emissions reduction plan. If the facility's plan was approved, it would be able to continue its operations during the restricted hours of 6:00 a.m to noon.

Solutia commented that the commission should allow hourly NO_x emission reductions from combustion unit shutdowns (for maintenance turnarounds) to offset the hourly NO_x emissions resulting from the operation of construction equipment during the proposed restriction period.

The commission disagrees with this comment. The commission cannot allow credits generated from stationary point sources to be used to offset emissions from mobile sources, as the emissions from these two sources differ in their potential to form ozone. Emissions from point sources are emitted higher into the atmosphere, while emissions from mobile sources are emitted at ground level. Therefore, these two types of emissions cannot be considered "equivalent" for purposes of banking, trading, or offsetting. However, facilities do have the option of applying for an exemption under §114.487(b) which, if approved, would allow continued operations during the restricted hours.

ARTBA, AGC-Texas, BFI, BCCA, ExxonMobil, GRBirdwell, HCIC, Kinder Morgan, Listo, PHA, SBU Texas, Union Pacific, WM, and two individuals commented that the commission proposed the draft SIP without a complete analysis and consideration of its economic feasibility and impacts. The plan lacks the required RIA, and was proposed without adequate notice, an adequate takings impact assessment, and an adequate small and micro-business assessment. The commission also failed to request a local employment impact statement from the Texas Workforce Commission. The proposed rule and the rulemaking process is procedurally defective because the commission erroneously concluded that adoption of the workday shift does not require an RIA. This conclusion is erroneous because the workday shift exceeds express requirements of state law, is not specifically required by federal law, and is adopted solely under the general powers of the agency. The workday shift is not a requirement of federal law because, as the commission acknowledges in the preamble (25 TexReg 8244) to the rules, the FCAA specifically defers to states in selection of measures to demonstrate attainment which is what the federal law does require. The workday shift is a measure that is the choice of the commission and is in no sense a requirement of federal law. There being no specific authority for the workday shift under state law, its only possible statutory basis is the commission's general powers. Because none of the exceptions apply, the commission is required to perform a RIA incident to the adoption of a major environmental rule in accordance with Texas Government Code, 2001.0225. The commission concedes that the workday shift is such a rule (25 TexReg 8244). Moreover, the commission was required to incorporate a draft impact analysis into the notice of the proposed rule. The commission devotes a single conclusory paragraph (25 TexReg 8243) to the potential impacts. This paragraph has limited cost figures that are attributed to the TxDOT and an unsupported estimate of an increment cost associated with the rule. The paragraph does not substantively address the requirements of §2001.025(c). The proposed rulemaking is thus procedurally defective. The commission failed to make the required initial determination of whether the rule has the potential to affect a local economy before proposing the rule for adoption, apparently ignoring that there is a great potential for the rules to adversely affect the local economy. BCCA commented that none of the plan's Small and Micro-Business Assessments applied the mandated cost comparison standards.

Regulatory Impact Analysis

The Texas Government Code, §2001.0225 applies to a major environmental rule adopted by a state agency, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

This rulemaking action does not meet any of these four applicability requirements, and is adopted in substantial compliance with the RIA requirements. Texas Government Code, §2001.035. These rules do not exceed an express standard set by federal law because the construction equipment operating restrictions are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. Title 42 USC, §7410 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 42 USC, §7410 does not specifically prescribe programs, methods, or reductions to meet the federal 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 42 USC, Chapter 85, Air Pollution Prevention and Control). The FCAA does require some specific measures for SIP purposes, such as an inspection and maintenance program, but those programs are the exception, not the rule, in the federal SIP structure. 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. In order to avoid federal sanctions, states must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission strategies necessary to attain the NAAQS. The commissions photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to shift the morning NO_x emissions thereby limiting the formation of after noon peak ozone levels Specifically, as noted elsewhere in this rule preamble, the limitation in after noon peak ozone production associated with these rules is a necessary element of the attainment demonstration required by the FCAA.

During the 75th Legislative Session, Senate Bill (SB) 633 amended the Texas Government Code to require agencies to perform a RIA of certain rules. The intent of SB 633 was to require agencies to conduct an RIA of major environmental rules that will have a material adverse impact, and that 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. 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. Because of the ongoing need to address nonattainment demonstrations required by federal law, the commission routinely proposes and adopts SIP rules. If each rule proposed for inclusion in the SIP was incorrectly considered as exceeding federal law, every SIP rule would require the full RIA contemplated by SB 633. This result would be inconsistent with the cost estimates and fiscal notes prepared by the commission and by the Legislative Budget Board (LLB). 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 meet the requirements under §2001.0225(a). 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. In other words, the proposed rules are intended to meet federal and state law, and does not go above and beyond what is required to meet federal or state statutes.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357

(Tex. App. Austin 1990, no writ).*Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd, Inc.*, 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor,* 24 S.W.3d 581 (Tex. App. - Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the APA by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified §2001.0225 as falling within this standard. The commission has substantially complied with the requirements of §2001.0225.

Rules adopted for inclusion in the SIP fall within the exception in Texas Government Code, §2001.0225(a), because they are required by federal law. The commission performed photochemical grid modeling which predicts that NO_x emission shifting, such as that required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area. This rulemaking does not exceed an express requirement of state law. This rulemaking is intended to result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law. The rulemaking does not exceed a standard set by federal law, does not exceed an express requirement of state law (unless specifically required by federal law), and does not exceed a requirement of a delegation agreement. The rulemaking was not developed solely under the general powers of the agency, but rather was specifically developed to meet the federal NAAQS under the authority of the Texas Clean Air Act (TCAA), §§382.011, 382.012, 382.017, 382.019, and 382.039.

Takings Impact Assessment

The primary reason the commission determined that these rules did not constitute a takings under Texas Government Code, Chapter 2007 is that they will not burden private real property. These rules apply to non-road equipment which is not real property or an appurtenance thereto.

In its analysis, the commission also found that the rules are exempt from Texas Government Code, Chapter 2007 pursuant to §2007.003(b)(4) because it is reasonably taken to fulfill an obligation mandated by federal law. The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking therefore meets the requirements of §2007.003(b)(4). For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree. To simply state that the proposal did not meet the statute or that compliance with the proposed rules is not technically or economically feasible does not provide the commission with sufficient information to propose changes or alternative strategies. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the notice must include the cost of a reasonable method of compliance. Mere disagreement with cost or technical feasibility estimates does not render notice inadequate.

Small Business Analysis

The commission disagrees with the commenters and believes that it has complied with Texas Government Code, §2006.002. Under that section the commission is required to prepare a statement of the effect of the rules on small businesses, including an objective assessment of the cost of compliance.

The purpose for performing the small business analysis and preparing the resulting statement is twofold. First, it puts the affected community on notice of the proposed rulemaking so that it can evaluate any potential fiscal impacts and then provide that information to the commission for its consideration prior to the commission's consideration of adoption of the rules. The second purpose of the analysis is to prevent the agency from adopting rules that would be unjustifiably burdensome to small businesses, while not similarly impacting large businesses.

In keeping with the statutory requirement a cost analysis was performed on these rules, and a statement of the analysis was published in the *Texas Register* concurrent with the proposed rulemaking. At the time the analysis was performed little was known or reasonably knowable with respect to the potential cost of compliance for small or large businesses. Because the proposed rules did not impose any emission standard or require the purchase or acquisition of any type or category of technology, there were no cost figures or even cost estimates to plug into any economic calculations, and therefore it was not feasible for the agency to calculate any meaningful potential impact on any business, small or large. This conclusion is supported by the fact that no comments were received from any potentially affected person besides a general assertion that the analysis was insufficient. No explanation of how the analysis was insufficient was provided, and in fact, no data was given at all with respect to any economic impact on any potentially affected business.

Nevertheless, this lack of available economic data did not stop the agency from doing its best to assess any potential economic impacts of the rules on potentially affected businesses. While it is true that the commission was unable to establish any definite cost figures, it did suggest, in the published rule proposal, that small and micro-businesses "may have significant fiscal implications" even though the amount could not be determined. The commission did attempt to extrapolate, however, potential fiscal implications as a result of comments received from North Central Texas Council of Governments (NCTCOG) and TxDOT on the DFW construction shift proposal. Based on these comments, the commission believes that costs associated with delays and extended construction schedules could potentially be in the range of 15% - 20%.

Local Employment Impact

The commission agrees with the commenters that the proposed rule may affect a local economy; however, it does not agree that it is the responsibility of the commission to provide the local employment impact analysis. The APA requires state agencies to determine whether a rule may affect a local economy before proposing a rule for adoption. If the agency determines that a proposed rule may affect a local economy, the agency must send a copy of the proposed rule and other information to the Texas Workforce Commission before the agency files notice of the proposed rule with the secretary of state. The APA requires the Texas Workforce Commission to prepare a local employment impact statement for proposed rules, if a state agency requests the statement. The Commission determined that the proposed rule might affect a local economy, and sent the proposed rule and other requested information to the Texas Workforce Commission. The commission received a letter from the Texas Workforce Commission, indicating that the Texas Workforce Commission did not have the ability to determine the potential local employment impacts from the proposed rules.

ARTBA, AGC-Texas, AAR, ASLRRA, BFI, BCCA, EMA, ExxonMobil, Harris County, HCIC, Union Pacific, and two individuals commented that the restrictions exceed federal mandates and statutory authority without proper justification and are therefore federally preempted and unlawful. The commission lacks statutory authority to impose the workday shift on all the equipment covered by the rule. The residual air quality benefit does not pass the practical and economically feasible test that commission rules must meet. An agency such as the commission must have legislative authority for its regulatory actions. The commission cites as statutory authority for the construction workday shift, the Texas Water Code, §5.103 (authority to adopt rules necessary to carry out its purposes and duties under the Water Code and other laws of the state), the TCAA, §§382.011 (authority to control the state's air), 382.012 (authority to develop a general, comprehensive plan for the control of the state's air), 382.017 (authority to adopt rules consistent with the policy and purposes of the TCAA), 382.019 (authority to adopt rules to control and reduce emissions from engines used to propel land vehicles), and 382.039 (authority to develop and implement transportation control programs and other measures necessary to demonstrate attainment and protect the public from exposure to hazardous air contaminants from motor vehicles). There is no specific statutory authority for imposition of the workday shift. The only statutory provision cited by the commission that deals with emissions from vehicles is §382.019 which is entitled "Methods Used to Control and Reduce Emissions From Land Vehicles". Section 382.019(a) reads as follows: "The commission may by rule provide requirements concerning the particular method to be used to control and reduce emissions from engines used to propel land vehicles." Subsection (a) is not authority to impose the workday shift because it is limited by its terms to controlling and reducing emissions from engines used to propel land vehicles. A prohibition against the operation of diesel engines in the morning hours affects the timing of emissions from engines, and it may in a general sense control emissions, but such a prohibition does not specifically control and reduce them. The prohibition neither imposes limits upon emissions nor does it reduce them. "Reduce" is the word the Legislature used in §382.019(a). Unless that word is written out of the sentence, actions taken pursuant to §382.019 must "reduce" emissions. Notwithstanding the rationale for the workday shift (theoretical reduction of ozone by shifting NO_x emissions), the statutory authority in §382.019 is to reduce "emissions." The same emissions of NO_x (including particulates and other materials produced by operation of diesel engines) are emitted either before or after noon; moving them to a different part of the day does not limit or reduce them. The language used in §382.019(a) is "control and reduce." This phrase is conjunctive; it does not say control or reduce. Both components must be present to be an exercise of the authority of §382.019(a). The commission can only regulate emissions from engines that propel land vehicles. The actions taken by the commission under §382.019(a) can lawfully only apply to specific engines, "those used to propel land vehicles." This limitation on the power of the commission is unambiguous. If an engine is not used to propel land vehicles, the commission has no authority to regulate with respect to that engine. However, the proposed workday shift covers a broader universe of engines. Some units of covered equipment cannot move at all without being towed or hauled on a trailer. These include crushing and processing equipment, signal boards, cement and mortar mixers (those not truck mounted), and others. Still other items of equipment can, in the broad sense, move as a result of their engine being operated but such movement is incidental to the device's function. Examples of these devices include: plate tampers, compactors and rammers, pavers, trenchers, boring rigs, concrete saws (movement regulates the speed of the blade through the material being sawed), surfacing equipment, excavators, and certain cranes (which must be repositioned). The devices just listed do not make use of an engine and transmission to move or propel themselves in any normal sense and are not within the language of §382.019(a), and the first list is certainly not. This point is reinforced by the definition of the term "motor vehicle," found in the Texas Transportation Act: *Motor vehicle - Any self propelled device powered by an internal combustion engine and designed to operate with four or more wheels in contact with the ground, in or by which a person or property is or may be transported, and is required to be registered under Texas Transportation Code (TTC), §502.002, excluding vehicles registered under TTC, §502.006(c).* The equipment discussed earlier in this paragraph is not designed to move people or property as its primary function and is not required to be registered. The conclusion drawn is that any attempted regulation by the commission of equipment, the movement of which is an incidental result of its engine, is outside the authority of the commission. Adoption of such a regulation would exceed the authority of the commission. The additional authorities, over and above TCAA, §382.019 cited by the commission, do not help establish power to regulate beyond the power to control and limit emissions from engines that propel land-based vehicles. The additional authorities are general provisions that cannot overcome the limits of §382.019. Specific authority to regulate may not be embellished through the expansion of general powers. Implied power is only permissible when it is first concluded that the legislature obviously intended the agency to have it. The language used in TCAA, §382.019 is measured and grants the ability to regulate in certain ways (control and limit emissions) as to certain devices (engines) used for certain purposes (propelling land vehicles). Little is left to the imagination and nothing else is "obviously" inferred. The critical point is that the commission may not regulate engines that do not *propel* land vehicles. Once those devices that are not within the authority are removed from the inventory, the NO_x emissions equivalent is reduced, and the modeled benefit of ozone reduction becomes minimal.

In addition to Texas Health and Safety Code, §382.019, the commission cites authority in §§382.011, 382.012, 382.017, and 382.039, all of which provide specific authority for this rulemaking and are not "general powers" of the agency. Section 382.019 specifically authorizes rules to reduce emissions from engines used to propel land vehicles. As noted by the commenter, engines subject to this rule are used, at least in part, to propel the equipment. The statute doesn't limit the commission's authority to engines which are used solely or primarily to propel engines. Therefore the commission asserts that §382.019 does provide authority for the adoption of this rule. Additionally, the presence of this authorization does not imply a lack of authority to control emissions from other types of vehicles or equipment. For these reasons, the commission disagrees that this rulemaking exceeds its statutory authority.

BFI commented that this rule violates the TCAA. Similar to its failure to conduct an analysis compliant with the Texas Government Code, the commission failed to conduct an analysis sufficient to determine the economic feasibility of the six-hour ban and the public health and general welfare impacts of that proposal as required by TCAA, §382.001 and §382.002.

The commission disagrees with the commenters and has made no change in response to these comments. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of the proposed rules. This information met the statutory requirements of the TCAA and the Texas APA because the information provided in the proposed rule was sufficient for commenters to submit alternative assessments of the costs and benefits.

BFI also commented that the six-hour ban violates the Supremacy Clause of the United States Constitution. Under the FCAA, the only two permissible means by which states may establish emission control standards for non-road engines and vehicles are the adoption of federal engine emission requirements, or the adoption of California standards. Congress has occupied the field of emission standards for non-road engines and vehicles and simultaneously prohibited parallel and/or contradictory state regulations in that particular field. By adopting this proposal, the commission has unlawfully adopted non-road engine and vehicle emission requirements that expressly conflict with and are thus preempted by §209 of the FCAA (42 USC, §7543(e)) and the Supremacy Clause of the United States Constitution (art. 6, cl. 2). Recent decisions by the federal courts have confirmed that the FCAA preemption provisions apply to the full range of non-road engines and vehicles that will be affected by the proposals at issue, and that the emission-related requirements established under the proposal clearly constitute the type of requirements that states are expressly preempted from adopting. See Engine Manufacturers Ass'n v. U.S. EPA, 88 F.3d 1075 (D.C. Cir. 1996) and American Automobile Mfrs. Ass'n v. Cahill, 152 F.3d 196, 200-01 (2d Cir. 1998).

The commission disagrees that these rules are preempted by federal law because they do not propose to "adopt or attempt to enforce any standard relating to the control of emissions," of any non- road engine or vehicle as described in Section 209 of the FCAA. Instead, these rules will establish time-of-day use restrictions on certain non-road diesel and industrial equipment rated at 50 hp or more, between the hours of 6:00 a.m. and noon, from April 1 through October 31. The rules do not in any way apply an emission control or emission standard to any of the subject equipment, and therefore do not create any emission-related requirements. Accordingly, the rules are not preempted under the FCAA. Because there is no preemption under federal law, these rules also do not violate the Supremacy Clause of the Constitution.

AAR, ASLRRA, and Union Pacific commented that the commission lacks authority to restrict the ability of railroads to maintain their rights-of-way and operate intermodal facilities, as per the Interstate Commerce Commission Termination Act, which gives the Surface Transportation Board exclusive jurisdiction over railroad transportation, including construction activities.

The commission disagrees with this comment and believes there is no conflict between the scope of these rules and the scope of the jurisdiction actually conferred to the Surface Transportation Board by the Interstate Commerce Commission Termination Act.

ARTBA, AGC-Texas, BFI, BCCA, and HCIC commented that the FCAA expressly prohibits Texas from claiming the intended SIP credit for the temporal emissions shift (dispersion techniques) in this proposal. "Dispersion techniques" are defined as "any intermittent or supplemental control of air pollutants varying with atmospheric conditions." This proposal is a classic "dispersion technique" because it shifts emissions in time to take advantage of varying atmospheric conditions.

Ozone is formed through chemical reactions between natural and man-made emissions of VOC and NO_x in the presence of sunlight. Higher ozone levels occur most frequently on hot summer afternoons. The critical time for the mixing of NO_x and VOCs is early in the day. By delaying the hours of operation for construction equipment and delaying the release of NO_x emissions until after noon during the ozone season, the NO_x emissions will not mix in the atmosphere with other ozone-forming compounds until after the critical mixing time has passed. Therefore, production of ozone will be stalled until later in the day when optimum ozone formation conditions no longer exist, ultimately reducing the peak level of ozone produced.

This strategy is not dependent on atmospheric conditions to reduce ozone formation, as such strategies are disfavored by FCAA, §7423. Instead, the strategy creates reductions in the amount of NO_x added to the atmosphere by construction equipment during the time of day when those emissions have been shown to contribute to exceedances of the ozone NAAQS. Use of "time of day" restrictions such as this for NAAQS compliance strategies was supported by the EPA in their off-road mobile source rules.

AGC-Texas, Baker Botts, Harris County, Union Pacific, and two individuals commented that the EPA should accept responsibility for the late promulgation of federal standards for non-road engines. The federal standards and their implementation schedule are key in the effort to address emissions from construction equipment. The commission has been forced to consider onerous strategies with regard to these engines that are not economically feasible. The commission should demand accountability from the EPA and be able to take credit for these reductions.

Baker Botts commented that the commission should incorporate into the SIP a greater level of reductions from federally preempted sources, such as low-sulfur diesel, non-road Tier 2/Tier 3 heavy- duty engine standards. The EPA delays in effectively regulating federally preempted sources have prompted the commission to propose technically and economically infeasible emission reductions from those sources in HGA that the state has authority to regulate to make up for the missing reductions. Based on established legal precedent, the commission and EPA have inherent authority to implement the intent of the FCAA by balancing federal and state reductions in the SIP approval process. The HGA situation warrants a flexible approach, due to both the uncertainties in acknowledging the role of NO_x reductions, and the EPA delays in adequately controlling the federally preempted sources as required by the FCAA.

Union Pacific commented that the EPA believes that a strong federal program that addresses remanufacturing and in-use compliance best achieves the necessary emission reductions. Also, a patchwork of state and local regulations would be inefficient and hinder the EPA's ability to implement a uniform national control program.

The commission agrees with the commenters that emission reductions from federally preempted sources would provide benefits for the HGA SIP demonstration, and the inability of the commission to regulate certain source categories has necessitated the use of other ozone control strategies. However, the commission understands that the EPA SIP approval process does not provide a mechanism for credit for emission reductions that occur after the attainment date. The commission understands that EPA is not currently considering accelerating implementation schedules for existing federal rules. The commission is working with EPA to determine the availability of SIP credit for many nontraditional control strategy mechanisms, like economic incentive programs and flexibility for preempted source categories. Additionally, the commission is working with EPA to determine an appropriate federal contribution credit available for the HGA SIP.

STATUTORY AUTHORITY

The new sections are adopted under Texas Water Code (TWC), §5.103, which authorizes the commission to adopt rules necessary to carry out its powers and duties under the TWC, and under Texas Health and Safety Code, TCAA, §382.017, which provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA. The new sections are also adopted under TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.019, which authorizes the commission to adopt rules to control and reduce emissions from engines used to propel land vehicles; and §382.039, which authorizes the commission to develop and implement transportation programs and other measures necessary to demonstrate attainment and protect the public from exposure to hazardous air contaminants from motor vehicles.

§114.482. Control Requirements.

No person shall start or operate any non-road diesel construction or industrial equipment, of 50 horsepower and above, between the hours of 6:00 a.m. and noon, from April 1 through October 31, in the counties listed in §114.489 of this title (relating to Affected Counties and Compliance Dates.)

§114.486. Recordkeeping Requirements.

(a) Any person that operates construction or industrial equipment described in §114.482 of this title (relating to Control Requirements) in those counties listed in §114.489 of this title (relating to Affected Counties and Compliance Dates) is subject to requirements of this section.

(b) Such person described in subsection (a) of this section shall provide to the executive director, or other air pollution program with jurisdiction, any records required to be maintained in accordance with this section within five working days of a written request from the executive director, or other air pollution program with jurisdiction.

(c) Such person described in subsection (a) of this section shall maintain daily operating records on the job site. These records must be maintained for a minimum of two years. The records at a minimum must contain:

(1) date(s) of operation;

(2) start and end times of daily operation;

(3) types of equipment being used; and

(4) name(s) of the equipment operator(s).

§114.487. Exemptions.

(a) The following uses of construction and industrial equipment are exempt from §114.482 and §114.486 of this title (relating to Control Requirements; and Record keeping Requirements) in the counties listed in §114.489 of this title (relating to Affected Counties and Compliance Dates):

(1) equipment used exclusively for emergency operations to protect public health and safety or the environment, including equipment being used to repair facilities, devices, systems, or infrastructure that have failed, or are in danger of failing, in order to prevent immediate harm to public health, safety, or the environment; and

(2) equipment used for mixing, transporting, pouring, or processing of wet concrete provided such equipment is actually processing wet concrete.

(b) Operators who submit an emissions reduction plan by May 31, 2002, which is approved by the executive director and the EPA no later than May 31, 2003, will be exempt from operating hour restrictions upon implementation of these rules in 2005, and will be permitted to operate during the restricted hours. The executive director may allow plans to be submitted after May 31, 2002. In any event, a plan must be approved prior to the use of that plan for compliance with the requirements of this division. In order to be approved, the plan must demonstrate nitrogen oxide reductions equivalent to those required by the rules being requested for exemption, and must contain adequate enforcement provisions. The operators may submit a plan for exemption from the control requirements of §114.472 of this title (relating to Control Requirements), §114.482 of this title, or both.

§114.489. Affected Counties and Compliance Dates.

Effective April 1, 2005, affected persons in the following counties shall be in compliance with §§114.482, 114.486, and 114.487 of this title (relating to Control Requirements; Recordkeeping Requirements; and Exemptions). These include Brazoria, Fort Bend, Galveston, Harris, and Montgomery Counties.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009078
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

SUBCHAPTER J. OPERATIONAL CONTROLS FOR MOTOR VEHICLES
DIVISION 1. MOTOR VEHICLE IDLING LIMITATIONS

30 TAC §§114.500, 114.502, 114.507, 114.509

The Texas Natural Resource Conservation Commission (commission) adopts new §114.500, Definitions; §114.502, Control Requirements for Motor Vehicle Idling; §114.507, Exemptions; and §114.509, Affected Counties and Compliance Dates. The commission adopts these new sections to Chapter 114, Control of Air Pollution From Motor Vehicles; new Subchapter J, Operational Controls for Motor Vehicles; new Division 1, Motor Vehicle Idling Restrictions; and corresponding revisions to the state implementation plan (SIP) in order to control ground-level ozone in the Houston/Galveston (HGA) ozone nonattainment area. These amendments are one element of the control strategy for the HGA Post-1999 Rate-of-Progress (ROP)/Attainment Demonstration SIP. Sections 114.500 and 114.507 are adopted *with changes* to the proposed text as published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8247). Sections 114.502 and 114.509 are adopted *without changes* to the proposed text and will not be republished.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

The HGA ozone nonattainment area is classified as Severe-17 under the Federal Clean Air Act (FCAA) Amendments of 1990 (42 United States Code (USC), §§7401 et seq.), and therefore is required to attain the one-hour ozone standard of 0.12 parts per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined by Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties, has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of its Post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base-case episodes, adopted rules to achieve a 9% ROP reduction in volatile organic compounds (VOC), and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary nitrogen oxide (NO_x) waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base-case episodes which marginally exhibited model performance in accordance with the United States Environmental Protection Agency (EPA) modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data-gathering exercise known as the COAST study. The state believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, the EPA policy regarding SIP elements and timelines went through changes. Two national programs in particular resulted in changing deadlines and requirements. The first of these programs was the Ozone Transport Assessment Group. This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in this study, and it has been concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that impacted the SIP planning process is the revisions to the national ambient air quality standard (NAAQS) for ozone. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, the EPA proposed an interim implementation plan (IIP) that it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development timelines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, that standard would continue to apply until it is attained. The FCAA requires that HGA attain the standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998 a revision to the HGA SIP which contained the following elements in response to EPA's guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by Subpart 2 of Title I of the FCAA to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the state eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs as well as an acceleration simulation mode equivalent motor vehicle inspection and maintenance program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory state-wide programs adopted or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon Scenario VIf); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review; and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-99 ROP plan by December 31, 2000; to perform a mid- course review by May 1, 2004; and to perform modeling of mobile source emissions using the EPA mobile source emissions model (MOBILE6), to revise the on-road mobile source budget as needed, and to submit the revised budget within 24 months of the model's release. In addition, if a conformity analysis is to be performed between 12 months and 24 months after the MOBILE6 release, the state will revise the motor vehicle emissions budget (MVEB) so that the conformity analysis and the SIP MVEB are calculated on the same basis.

In order for the state to have an approvable attainment demonstration, the EPA indicated that the state must adopt those strategies modeled in the November submittal and then adopt sufficient controls to close the remaining gap in NO_x emissions. The modeling and other analysis supporting these rules and the HGA SIP indicate a gap of approximately an additional 91 tons per day (tpd) of NO_x reductions is necessary for an approvable attainment demonstration. The commission estimates that this measure will achieve a minimum of 0.48 tpd of NO_x equivalent reductions and is therefore a necessary measure to consider for closing the gap and successfully demonstrating attainment.

The emission reduction requirements included as part of this SIP revision represent substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

This rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000 and planned to be submitted to EPA by December 31, 2000.

The amount of NO_x reductions required for the area to attain the ozone NAAQS has 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 reduction strategies. The FCAA, 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 oversight committee. Commission staff have continued to improve the air quality modeling technology and refine emission inventory data. Numerous emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources, on-road and non-road mobile sources, and area sources were analyzed in multiple iterations of modeling, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling and other analysis submitted for public hearing and comment concurrently with the HGA SIP show that a significant amount of NO_x reductions practicably achievable are necessary from ozone control strategies in order for the HGA nonattainment area to achieve the ozone NAAQS by 2007, including reductions from surrounding counties included in the HGA consolidated metropolitan statistical area (CMSA).

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies. At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The current SIP revision contains rules, enforceable commitments, photochemical modeling analyses, and calculation of the remaining NO_x reductions required to reach attainment (gap calculation) in support of the HGA ozone attainment demonstration. In addition, this SIP contains post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contains enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit a mid- course review.

The HGA ozone nonattainment area will need to ultimately reduce NO_x more than 750 tpd to reach attainment with the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of these rules limiting idling of heavy-duty motor vehicles will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area. These rules may also contribute to a successful demonstration of transportation conformity in the HGA area.

These rules are one element of the control strategy for the HGA Attainment Demonstration SIP. The purpose of these rules is to establish heavy-duty motor vehicle idling restrictions as one element of an air pollution control strategy in the eight-counties HGA ozone nonattainment area to reduce NO_x necessary for the counties to be able to demonstrate attainment with the ozone NAAQS.

These rules will implement idling limits for gasoline and diesel-powered engines in heavy-duty motor vehicles in the HGA area. These idling limits will lower NO_x emissions and other pollutants from fuel combustion. Because NO_x is a precursor to ground-level ozone formation, reduced emissions of NO_x will result in ground-level ozone reductions. To comply with the motor vehicle idling regulations, no person in the affected counties may cause, suffer, allow, or permit the primary propulsion engine of a heavy-duty motor vehicle to idle for more than five consecutive minutes when the vehicle is not in motion during the time period April 1 through October 31.

The commission developed an ozone control strategy which limits the time allowed for the engines of heavy-duty motor vehicles to idle when not in motion. Currently, there are no federal regulations governing idle time for heavy-duty motor vehicles. Therefore, the state has the authority to control motor vehicle idling and the requirements developed by the commission for this NO_x emission reduction strategy will result in restrictions on the time allowed for motor vehicle idling.

Modeling assessing the benefits of this NO_x emission reduction strategy demonstrated that emission reductions could be achieved by limiting the idling time of heavy-duty motor vehicles. By the year 2007, the idling limits will reduce NO_x emissions in the affected area by 0.48 tpd. The commission estimates the daily cost savings benefit of this strategy to be approximately $51,900 per ton of NO_x reduced. This figure was calculated from the estimated NO_x reductions from this strategy of 0.48 tpd, the estimated reduction in fuel consumption per hour, and the current price per gallon of fuel sold in the affected area.

The commission solicited comment on additional flexibilities relating to rule content and implementation which have not been addressed in this or other concurrent rulemakings. These flexibilities may be available for both mobile and stationary sources. Additional flexibilities may also be achieved through innovative and/or emerging technology which may become available in the future. Additional sources of funds for incentive programs may become available to substitute for some of the measures considered here. The commission received six comments on additional flexibilities which are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

SECTION BY SECTION DISCUSSION

The new §114.500 contains the definitions for idle, motor vehicle, and primary propulsion engine. The commission added language to the primary propulsion engine definition to clearly state that these rules are applicable to only gasoline or diesel fueled vehicles.

The new §114.502 establishes the control requirements that limit motor vehicle idling to five consecutive minutes when the vehicle is not in motion during the time period April 1 through October 31.

The new §114.507 provides exemptions to the control requirements of §114.502 for motor vehicles that have a gross vehicle weight rating (GVWR) of 14,000 pounds or less; that are forced to remain motionless because of traffic conditions over which the operator has no control; are being used as an emergency or law enforcement motor vehicle; when the engine of a motor vehicle is being operated for maintenance or diagnostic purposes; or when the engine of a motor vehicle is being operated solely to defrost a windshield. As a result of comments, the commission revised language in §114.507(4) to exempt vehicles being operated to provide a power source necessary for mechanical operation other than propulsion, passenger compartment heating, or air conditioning. Also, as a result of comments, the commission added language to provide the following additional exemptions: §114.507(7) where the primary propulsion engine of a motor vehicle is being operated to supply heat or air conditioning necessary for passenger comfort/safety in those vehicles intended for commercial passenger transportation or school buses, in which case idling up to a maximum of 30 minutes is allowed; §114.507(8) where the primary propulsion engine of a motor vehicle is being used for transit operations, in which case idling up to a maximum of 30 minutes is allowed; and §114.507(9) where the primary propulsion engine of a motor vehicle is being used in airport ground support equipment. The exemption for ground service equipment in §114.507(9) is intended to cover all equipment that is used to service aircraft during passenger and/or cargo loading and unloading, maintenance, and other ground-based operations. Exemptions from this category of equipment which may exist in other rules or agreements such as freezing weather equipment or leased equipment do not apply here.

The new §114.509 establishes a compliance date of April 1, 2001, and identifies the eight HGA counties covered by the motor vehicle idle control requirements of §114.502.

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed this rulemaking action in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and determined that this rulemaking action is not subject to §2001.0225 because it does not meet the definition of a "major environmental rule" as defined in that statute. "Major environmental rule" means a rule of which the specific intent 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.

These adopted rules do not meet any of the four applicability criteria for requiring a regulatory analysis of "major environmental rule" as defined in the Texas Government Code. Section 2001.0225 applies only to a major environmental rule the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law. The new sections in Chapter 114 are intended to protect the environment and reduce risks to human health from environmental exposure to ozone, but the control requirements within these rules should not adversely affect in any 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. These rules are intended to implement heavy-duty motor vehicle idle limitations as part of the strategy to reduce emissions of NO_x necessary for the counties included in the HGA ozone nonattainment area to be able to demonstrate attainment with the ozone

NAAQS. These rules are one element of the Attainment Demonstration SIP.

These rules do not exceed an express standard set by federal law, since they implement requirements of the FCAA. Under 42 USC, §7410, states are required to adopt a SIP which provides for "implementation, maintenance, and enforcement" of the primary NAAQS in each air quality control region of the state. These rules were specifically developed as part of an overall control strategy to meet the ozone NAAQS set by the EPA under 42 USC, §7409. While 42 USC, §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 42 USC, Chapter 85, Air Pollution Prevention and Control). It is true that the FCAA does require some specific measures for SIP purposes, such as 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 42 USC, §7410. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to achieve emission reductions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. By policy, the EPA requires photochemical grid modeling to demonstrate whether the 42 USC, §7511a(f), NO_x measures would contribute to ozone attainment. The commission has performed photochemical grid modeling which predicts that NO_x emission reductions, such as those required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The 42 USC, §7511a(f), exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under 42 USC, §7511a(f), was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

During the 75th Legislative Session, Senate Bill (SB) 633 amended the Texas Government Code to require agencies to perform a regulatory impact analysis (RIA) of certain rules. The intent of SB 633 was to require agencies to conduct a RIA of extraordinary rules. 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 previously discussed, 42 USC 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 proposes and 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. Because 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 42 USC.

The TNRCC has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.- -Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Specifically, the motor vehicle idle requirements within these rules were developed in order to meet the ozone NAAQS set by the EPA under 42 USC, §7409, and therefore meet a federal requirement. States are primarily responsible for ensuring attainment and maintenance of NAAQS once the EPA has established those standards. Under 42 USC, §7410 and related provisions, states must submit, for EPA approval, SIPs that provide for the attainment and maintenance of NAAQS through a control program directed to sources of the pollutants involved. These rules are not an express requirement of state law, but were developed specifically in order to meet the air quality standards established under federal law as NAAQS. These rules are intended to help bring ozone nonattainment areas into compliance and to help keep attainment and near nonattainment areas from reaching nonattainment. These rules do not exceed a standard set by federal law, exceed an express requirement of state law unless specifically required by federal law, nor exceed a requirement of a delegation agreement. These rules were not developed solely under the general powers of the agency, but were specifically developed to meet the air quality standards established under federal law as NAAQS.

The commission solicited public comment on the draft regulatory impact analysis and received four comments. These comments are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

TAKINGS IMPACT ASSESSMENT

The commission evaluated this rulemaking action and performed an analysis of whether the rules are subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. The specific purpose of the rulemaking action is to establish motor vehicle idle limits which will act as an air pollution control strategy to reduce NO_x emissions necessary for the eight- county HGA ozone nonattainment area to be able to demonstrate attainment with the ozone NAAQS. Promulgation and enforcement of these rules should not burden private, real property because this rulemaking action should not result in any increased costs. Also, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although these 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 advance the health and safety purpose. In addition, §2007.003(b)(4) provides that Chapter 2007 does not apply to these adopted rules since it is reasonably taken to fulfill an obligation mandated by federal law. The purpose of the rules is to implement motor vehicle idle limits which are necessary for the HGA ozone nonattainment area to meet the air quality standards established under federal law as NAAQS. This action is taken in response to the HGA area exceeding the NAAQS for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient NO_x and ozone levels in HGA. Attainment of the ozone standard will eventually require substantial NO_x reductions. Any NO_x reductions resulting from the current rulemaking are no greater than what the best scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard. The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

The commission received three comments on the TIA which are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission determined that this rulemaking action relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et seq.), and the commission rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with the CMP. 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 reviewed this action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and determined that the action is consistent with the applicable CMP goals and policies. The CMP goal applicable to this rulemaking action is to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(1)). No new sources of air contaminants will be authorized and NO_x air emissions will be reduced as a result of these rules. The CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations in 40 Code of Federal Regulations (CFR), to protect and enhance air quality in the coastal area (31 TAC §501.14(q)). This rulemaking action complies with 40 CFR 50, National Primary and Secondary Ambient Air Quality Standards, and 40 CFR 51, Requirements for Preparation, Adoption, and Submittal Of Implementation Plans. Therefore, in compliance with 31 TAC §505.22(e), this rulemaking action is consistent with CMP goals and policies.

The commission solicited comments on the consistency of the proposed rules with the CMP during the public comment period. The commission received no comments on the CMP.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000.

The following commenters provided oral testimony and/or submitted written testimony: Dow Chemical Company (Dow); Houston Metropolitan Transit Authority (Metro); Harris County Judge, Robert Eckels (Harris County); Sierra Club Houston Regional Group (Sierra-Houston); Port of Houston Authority (PHA); Texas Chemical Council (TCC); Pony Pack, Inc. (Pony Pack); ExxonMobil Corporation (ExxonMobil); Phillips 66 Company (Phillips 66); Rhodia, Inc. (Rhodia); Reliant Energy, Inc. (REI); Public Citizen; Baker Botts; Enterprise Products Operating L.P. (Enterprise); Business Coalition for Clean Air (BCCA); Paso del Norte Clean Cities Coalition and Clean Air Partnership (Paso del Norte); Mothers for Clean Air (MCA); League of Women Voters of Texas (LWV-TX); Texas Natural Resource Conservation Commission - Public Interest Counsel (PIC); City of Missouri City (Missouri City); City of Spring Valley (Spring Valley); RMT, Inc. on behalf of Montgomery County (Montgomery Co.); Lloyd, Gosselink, Blevins, Rochelle, Baldwin, and Townsend, P.C. on behalf of BFI Waste Systems of North America, Inc. (BFI); Waste Management (WM); BP Petrochemical Companies of Texas (BP); Texas Taxpayer Rebellion (TTR); Texas Citizens for a Sound Economy (CSE); and 44 individuals.

The following commenters generally supported the proposal: Dow, PIC, MCA, LWV-TX, Paso del Norte, PHA, Enterprise, Pony Pack, Sierra-Houston, Public Citizen, Baker Botts, BCCA, ExxonMobil, Phillips 66, TCC, Rhodia, REI, Missouri City, Spring Valley, Harris County, Metro, BP, and 32 individuals.

The following commenters generally opposed the proposal: Montgomery Co., BFI, WM, TTR, CSE, and 12 individuals.

The following commenters suggested changes to the proposal as stated in the ANALYSIS OF TESTIMONY section of this preamble: Dow, PIC, MCA, Sierra-Houston, Public Citizen, PHA, TCC, Paso del Norte, BCCA, Enterprise, Pony Pack, ExxonMobil, Phillips 66, Rhodia, REI, Metro, Missouri City, Spring Valley, Montgomery Co., BFI, WM, and 24 individuals.

ANALYSIS OF TESTIMONY

Legal Action

TTR stated that they intend to take legal action to stop the implementation of the plan if the idling restriction strategy is adopted.

The SIP and SIP rules were proposed and will be adopted in full compliance with all requirements of the TCAA and the APA. These rules implement measures necessary to reach attainment of the one-hour ozone standard in the HGA area, as required under 42 USC, §7409.

Enforcement

BFI, MCA, Rhodia, TCC, Spring Valley, and ten individuals inquired about who would enforce these rules, and commented that enforcement of the rules would be difficult, impossible, and/or expensive. Sierra-Houston inquired as to how the commission would ensure enforcement of those from another area or state ticketed for violating the idling restrictions.

The commission will work with local officials to ensure enforcement of the SIP and SIP rules. The commission has existing relationships with pollution control authorities in the City of Houston, Harris County, and Galveston County for enforcement of other commission rules. The commission will continue enforcement relationships with these entities and develop relationships with other local officials as needed to create effective enforcement mechanisms for the SIP and SIP rules. Local governments are not required to enforce commission rules, but may sign cooperative agreements with the commission to enforce the rules under TCAA, §382.115, Cooperative Agreements. Local programs can also enforce commission rules without signing a cooperative agreement. The authority of local governments to enforce air pollution requirements is specified in detail in TCAA, §§382.111 - 382.115, and local governments can institute civil actions in the same manner as the commission under Texas Water Code (TWC), §7.351.

Costs for Training Employees & Modifying Existing Equipment

Missouri City commented that compliance with the idling restrictions would cost the city to train their employees and modify existing equipment.

The commission anticipates little or no costs to train a company's employees to comply with the idling restrictions. Compliance with the idling restrictions does not require equipment modification. The commission made no changes to the rule language in response to this comment.

Funding for Alternative Cooling/Heating Infrastructure

Public Citizen commented that funding for an alternative cooling and heating infrastructure will have to be put in place.

The commission is unaware of any alternative cooling and heating infrastructure that would be necessary to comply with the idling restrictions. The commission made no changes to the rule language in response to this comment.

Railroad Crossings

Two individuals commented that they felt the idling restrictions should not be enforced if a vehicle was stopped due to a train crossing the roadway which typically takes longer than five minutes.

The commission agrees. A vehicle stopped due to a train crossing the roadway would not be subject to the idling restrictions, and would be covered by the exemptions provided in the rules in §114.507(2). The commission made no changes to the rule language in response to this comment.

Nights and Rainy Days

One individual commented it would be illogical to apply the idling restrictions at night, on rainy days, and on sunny days which are preceded by lower ozone readings.

The commission disagrees with this comment. Applying the idling restrictions only during certain hours of the day or during certain weather conditions would make it difficult for those affected to know when the restrictions would apply. The rules do limit, in §114.502, the idling restrictions to the ozone season for the HGA nonattainment area. The commission made no changes to the rule language in response to this comment.

Apply Idle Restrictions Statewide or to All Vehicles

Five individuals commented that they would like to see idling restrictions in place for all motor vehicles. Sierra-Houston, Paso del Norte and one individual stated they think the idling restrictions should apply statewide. Spring Valley and one individual suggested that the idling restrictions should apply to vehicles with a gross vehicle weight rating (GVWR) greater than 10,000 pounds, while Sierra- Houston suggested the idling restrictions should apply to vehicles with a GVWR greater than 8,000 pounds.

These rules are targeted at vehicles with a GVWR greater than 14,000 pounds, which are typically diesel and have less stringent emission standard requirements than light-duty vehicles. This allows the rules to achieve the greatest amount of emissions reductions while affecting the fewest number of vehicles. As noted in the preamble, the purpose of these rules is to establish an idling restriction control strategy to reduce NO_x emissions necessary for the HGA nonattainment area to be able to demonstrate attainment with the ozone NAAQS.

The commission appreciates the support for state-wide applicability of the rules. The commission notes, however, that it is not obligated to adopt all rules statewide in order to satisfy its commitments under the SIP, nor is the commission required to do so under 42 USC. Three of the measures contained emissions reduction strategies that have been proposed for state-wide applicability: California large-spark ignition engines; emissions banking and trading program (that portion of the rules which relates to the trading of emission reduction credits and discrete emission reduction credits); and low emission diesel fuel (that portion of the rules which relates to on-road fuel).

In evaluating whether to implement all of the rules statewide, the commission took into account many concerns, including but not limited to: the need for the marketplace to be able to respond to regulation, the possible impacts on transport and distribution systems, the possibility of increased costs and financial burdens on regulated entities, and regional needs and issues associated with statewide mandates. The commission analyzed where emissions reduction measures are most needed and where emissions reduction measures will be most effective in order to demonstrate attainment. The commission made no changes to the rule language in response to this comment.

Drive-Thru Lanes

Sierra-Houston and six individuals commented that the idling restrictions should also apply to vehicles at drive-thru lanes, such as restaurants, banks, cleaners, and pharmacies.

The commission agrees with this comment. The idling restrictions apply in drive-thru lanes to any vehicle with a GVWR greater than 14,000 pounds. The commission made no changes to the rule language in response to this comment.

High Ozone Season, Daylight Savings Time, Year-Round

One individual commented the idling restrictions should only apply during the HGA area's high ozone season, mid-August through mid-September. If not during this high ozone season, the same individual and Spring Valley stated the idling restrictions should coincide with the construction equipment operating restrictions period which only applies during Daylight Savings Time, which is the first weekend in April through the last weekend in October of each year. Pony Pack commented the idling restrictions should be effective year-round instead of April 1 through October 31.

Historically, the proper weather conditions (light winds, heat, and sunshine) that can produce high ozone level of in the HGA nonattainment area occur mainly during the months of April through October. As a note, the commission changed the effective period for the construction equipment operating restrictions rules from Daylight Savings Time to the time period April 1 through October 31 in order to be consistent with the other rules. The commission made no changes to this rule language in response to this comment.

Out-of-State Vehicles

Pony Pack commented the idling restrictions should be clarified to indicate that they apply to out- of-state vehicles which park and idle overnight in the area.

The commission believes that §114.502 clearly states that the idling restrictions apply to all affected vehicles operated in the nonattainment counties listed in §114.507. This includes long-haul trucks and any other affected vehicles that may be simply passing through the nonattainment area. The commission made no changes to the rule language in response to this comment.

"Restarting Motor" and "In Gear" Loophole

BFI and PHA commented there was a loophole in the idling restriction rules that would simply allow a driver to idle for five minutes, shut off the motor, then immediately restart the motor triggering a new five-minute idle period. Sierra-Houston commented there was a loophole in the idling restriction rules that would simply allow a driver to keep the vehicle in gear to avoid violating the rules.

Although these situations could occur, the commission anticipates that most drivers/organizations will comply with the rules to realize the potential cost savings and emissions reductions from unnecessary idling. The commission made no changes to the rule language in response to this comment.

Idling for Heat or Air Conditioning

BFI, TCC, Rhodia, Enterprise, and four individuals commented that drivers need to idle their vehicle to operate the heating and air conditioning systems in order to stay comfortable in the extreme temperatures of Texas. TCC, Dow, and Rhodia commented that this was required for trucks in line at their gates or in staging areas for loading or unloading materials, or to weigh-out when leaving the plant. TCC and Dow further commented that the commission should clarify that vehicles idling for this reason meet the intent of exemption §114.507(2). One individual commented that school district buses that transport special education students are required by federal law to keep the bus cool to prevent possible seizures.

The commission anticipates that idling restrictions will encourage innovative solutions to excessive idling, such as revised queing procedures or the addition of auxiliary power units (APUs) to power passenger compartment heating, air conditioning, and auxiliary systems. If a situation occurs that involves idling longer than five minutes, and the situation is not covered by an exemption, then the commission believes the engine should not be idled. The intent of exemption §114.507(2) was to cover the typical roadway traffic situations, such as congestion and traffic lights. The commission made no changes to the rule language in response to this comment. In the case of school district buses transporting special education students, the commission added rule language in §114.507(7) that includes a maximum 30-minute idling period for school bus operations.

Idling Necessary for On-board Pumps and Auxiliary Systems

Enterprise commented that idling a vehicle is necessary to operate on-board pumps and to circulate coolant through coils in the product trailer to keep the product within the appropriate temperature range.

The commission anticipates that idling restrictions will encourage innovative solutions to excessive idling, such as the addition of APUs to power passenger compartment heating, air conditioning, and auxiliary systems. The commission understands, however, that an APU cannot always be used to provide the necessary power required for all situations requiring product heating or cooling. Therefore, the commission rewrote the exemption language in §114.507(4) to cover possible situations in which the primary propulsion motor is used to power mechanical operations other than propulsion and passenger compartment heating/air conditioning.

Idling to Cool Motor

One individual commented that certain types of heavy-duty vehicles would need to idle longer than a five-minute period in order to properly cool the motor after being under extreme load.

The commission anticipates that for most situations a maximum five-minute idling time is sufficient for heavy-duty engines to cool to a reasonable temperature after operating at extreme loads, and then be shut down without causing engine damage. The commission made no changes to the rule language in response to this comment.

Case-by-Case Review

TCC commented that a case-by-case review for the idling restrictions should be added.

The commission anticipates that idling restrictions will encourage innovative solutions to excessive idling, such as the addition of APUs to power passenger compartment heating, air conditioning, and auxiliary systems. If a situation occurs that involves idling longer than five minutes, and the situation is not covered by an exemption, then the commission believes the engine should not be idled. The commission believes it is more appropriate for the individual or business to review their own procedures to resolve any possible excessive idling situations that contribute to unnecessary pollutants and wasted fuel. The commission made no changes to the rule language in response to this comment.

Possible Conflict with Tailpipe Test

One individual commented that the idling rule may be in conflict with the proposed tailpipe testing procedure which may take longer than five minutes.

The commission disagrees with the comment. The current two-speed idle test consists of an average idle time of two minutes, and idling is not required during the acceleration simulation mode test. Additionally, the exemption in §114.507(5) applies to "the primary propulsion engine of a motor vehicle being operated for maintenance or diagnostic purposes." The commission made no changes to the rule language in response to this comment.

Exemption of Waste Facilities and Maritime Terminals

WM commented that collection vehicles idle frequently during loading and unloading at residences, businesses, transfer stations, and landfills. BFI commented that municipal solid waste facilities should be exempt from the idling restrictions. PHA suggested an exemption for vehicles in line to enter a maritime terminal, loading or unloading facility, or in queue on the terminal awaiting service. As an alternative to an exemption, PHA suggested the five-minute idling period be lengthened to ten minutes. TCC commented that the commission should specifically add vacuum trucks to exemption §114.507(4) to clarify that these trucks must idle to provide power takeoff for the vehicle's designed use.

The commission anticipates that idling restrictions will encourage innovative solutions to excessive idling, such as revised queing procedures or the addition of APUs to power passenger compartment heating/air conditioning and auxiliary systems. If a situation occurs that involves idling longer than five minutes, and the situation is not covered by an exemption, then the commission believes the engine should not be idled. However, the commission rewrote the exemption language in §114.507(4) to cover possible situations in which the primary propulsion motor is being used to power mechanical operations other than propulsion or passenger compartment heating/air conditioning.

Violation of the TCAA

BFI commented that the proposed idling restrictions violated the TCAA by not determining the public health and general welfare impacts of the idling rule as required by Texas Health and Safety Code, TCAA, §382.011 and §382.002.

The commission disagrees with the commenter and has made no change in response to these comments. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of the proposed rules. This information met the statutory requirements of the TCAA and the APA because the information provided in the proposed rules was sufficient for commenters to submit alternative assessments of the costs and benefits.

Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rules. *United Loans, Inc. v. Pettijohn*, 955 S.W.2d 649, 651 (Tex. App.- Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The commission received intelligent comments, which were substantial in both number and in scope, regarding the costs of the proposed rules and the technical practicability of compliance. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree. To simply state that the proposal did not meet the statute or that compliance with the proposed rules is not technically or economically feasible does not provide the commission with sufficient information to propose changes or alternative strategies. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the notice must include the cost of a reasonable method of compliance. Mere disagreement with cost or technical feasibility estimates does not render notice inadequate.

The commenter did not say how the notice is insufficient, merely that it is insufficient. Nevertheless, the commission has reviewed the notice and has determined it is adequate.

Lack of Adequate Notice, RIA, TIA, Small and Micro-Business Assessment (SMBA), Local Employment Impact Statement (LEIS)

ExxonMobil, PHA, and WM commented that the commission failed to provide interested parties with sufficient information to constitute adequate notice. BFI commented the commission should defer imposing the idling restrictions until the net benefit of the rules can be determined on ozone reduction, and a demonstration of compliance with the RIA requirements and the economic reasonableness test. PHA, WM, and ExxonMobil commented on their belief that the idling rule qualifies as a "major environmental rule," which requires an RIA, TIA, SMBA, and LEIS.

The commission disagrees with the commenters and has made no change in response to these comments. Texas Government Code, §2001.024 requires the notice of a proposed rule to include certain information. Subsection (a)(5) requires that the notice state the public benefits expected as a result of the adoption of the proposed rule and the probable economic cost to persons required to comply with the rule. Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn*, 955 S.W.2d 649, 651 (Tex. App. - Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of the proposed rules. The commission received intelligent comments, which were substantial in both number and in scope, regarding the costs as well as the benefits. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the notice must include the cost of a reasonable method of compliance.

The commenters' statements that the costs were "dramatically underestimated" did not state how that conclusion was reached. Similarly, the comments which state there are critical gaps did not identify what those gaps are or how that results in inadequate notice. Mere disagreement with cost estimates does not render notice inadequate.

To simply state that the proposal failed to provide sufficient information does not provide the commission with sufficient information to propose changes or alternative strategies. The commenters did not say how the notice was insufficient, merely that it was insufficient. Nevertheless, the commission has reviewed the notice and has determined it was adequate. The commission is unaware of any requests for additional information to which it was not completely responsive.

The commission disagrees with ExxonMobil, PHA, and WM that the proposed rules meet the definition of a major environmental rule. Texas Government Code, §2001.0225 only applies to a major environmental rule adopted by a state agency, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

This rulemaking action does not meet any of these four applicability requirements, and is adopted in substantial compliance with the RIA requirements of Texas Government Code, §2001.035. These rules do not exceed an express standard set by federal law because the idling restrictions were specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. Title 42 USC, §7410 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 42 USC, §7410 does not specifically prescribe programs, methods, or reductions to meet the federal 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 42 USC, Chapter 85, Air Pollution Prevention and Control). It is true that 42 USC does require some specific measures for SIP purposes, such as an inspection and maintenance program, but those programs are the exception, not the rule, in the federal SIP structure. The provisions of 42 USC 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. In order to avoid federal sanctions, 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. Failure to develop control strategies to demonstrate attainment can result in federal sanctions. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by 42 USC. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with 42 USC. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking action is intended to achieve reductions in ozone precursor emissions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by 42 USC.

These federal requirements are incorporated in the TCAA, §§382.011, 382.012, 382.017, 382.019, 382.037(g), and 382.039; and therefore, the proposed rules do not exceed state requirements, and are not adopted solely under the general powers of the agency. The fourth requirement, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Under this analysis, even if the SIP rules may be considered major environmental rules, they fall under the exceptions of Texas Government Code, §2001.0225(a). Thus, the commission is not required to conduct a regulatory analysis as provided in §2001.0225(b) and (c).

This conclusion is supported by the legislative history for Texas Government Code, §2001.0225. During the 75th Legislative Session, SB 633 amended the Texas Government Code to require agencies to perform an RIA of certain rules. The intent of SB 633 was to require agencies to conduct an RIA of 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. 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. Because of the ongoing need to address nonattainment demonstrations required by federal law, the commission routinely proposes and adopts SIP rules. If each rule proposed for inclusion in the SIP was incorrectly considered as exceeding federal law, every SIP rule would require the full RIA contemplated by SB 633. This result would be inconsistent with the cost estimates and fiscal notes prepared by the commission and by the LBB. Because 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 meet the requirements under §2001.0225(a). While the SIP rules will have a broad impact, that impact is no greater than is necessary or appropriate to meet the requirements of 42 USC. In other words, the proposed rules are intended to meet federal and state law, and do not go above and beyond what is required to meet federal or state statutes.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the APA by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

This rulemaking action is intended to obtain reductions in ozone formation in the HGA, Beaumont/Port Arthur, and Dallas/Fort Worth ozone nonattainment areas, and the 95-county central and eastern Texas region, and help bring HGA into compliance with the air quality standards established under federal law. Therefore, under Texas Government Code, §2001.0225, an RIA is not required.

The primary reason the commission determined that this rulemaking action did not constitute a takings under Texas Government Code, Chapter 2007, is that it will not burden private real property. These rules apply to non-road equipment which is not real property or appurtenance thereto.

In its analysis, the commission also found that these rules are exempt from Texas Government Code, Chapter 2007, under §2007.003(b)(4) because they are reasonably taken to fulfill an obligation mandated by federal law. The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the federally-mandated SIP. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary, and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking action therefore meets the requirements of §2007.003(b)(4). For these reasons these rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

The commission agrees with the commenter that the proposed rules may affect a local economy; however, it does not agree that it is the responsibility of the commission to provide the local employment impact analysis. The APA requires state agencies to determine whether a rule may affect a local economy before proposing a rule for adoption. If the agency determines that a proposed rule may affect a local economy, the agency must send a copy of the proposed rule and other information to the Texas Workforce Commission (Workforce Commission) before the agency files notice of the proposed rule with the Secretary of State. The APA requires the Workforce Commission to prepare a local employment impact statement for proposed rules, if a state agency requests the statement. The commission determined that the proposed rules might affect a local economy, and sent the proposed rules and other requested information to the Workforce Commission. The commission received a letter from the Workforce Commission, indicating that the Workforce Commission did not have the ability to determine the potential local employment impacts from the proposed rules.

The commission estimated, to the extent possible, the costs to small businesses and determined that there should be no significant costs as a result of this rule, but there could be cost savings as a result of reduced fuel consumption. The cost savings depend more upon the number of heavy-duty diesel and gasoline-powered vehicles operated by the business, and are not dependent upon the number of employees, hours of labor, or amount of sales income. Some small businesses have only one heavy-duty diesel and gasoline-powered vehicle while others have large fleets. Large businesses vary in the same way, in that the size of the fleet is not dependent upon the size of the business. The commission provided the estimated savings per heavy-duty diesel and gasoline-powered vehicle and believes that this is the only meaningful way to provide sufficient notice of the cost or savings to small business. Therefore, this method of assessing the impact on small business meets the objective of Chapter 2006 of the Texas Government Code. This assertion is supported by the fact that no small businesses provided comments which include cost of compliance in terms of the number of employees, hours of labor, or amount of sales income.

Lack of Environmental Benefit

BFI commented that the idling restrictions will not provide measurable environmental benefit. One individual commented that the impact of the idling restrictions in the peripheral metropolitan counties would be negligible. Montgomery Co. commented that the idling rules do not derive significant NO_x reductions from Montgomery County, and that the county should be excluded from the idling restrictions.

The purpose of these rules is to establish an idling restriction control strategy to reduce NO_x emissions necessary for the HGA nonattainment area to be able to demonstrate attainment with the ozone NAAQS. Montgomery County is classified by the EPA in 40 CFR §81.344 as a severe ozone nonattainment area, and therefore the commission is not removing Montgomery County from the idling restrictions, which is designed to help the entire HGA nonattainment area demonstrate attainment.

The FCAA Amendments of 1990 provided new requirements for areas that had not attained the NAAQS for ozone, carbon monoxide, particulate matter, sulfur dioxide, nitrogen dioxide, and lead, and new requirements for SIPs in general. The EPA was authorized to designate areas failing to meet the NAAQS for ozone as nonattainment and to classify them according to severity. The FCAA, §107(d)(4)(A)(iv) mandated that areas designated as serious, severe, or extreme for ozone that were within a metropolitan statistical area (MSA) or CMSA must have boundaries that include the entire MSA or CMSA. This requirement is supported by the legislative history for the 1990 FCAA Amendments in Senate Report No. 101-228, page 3399, "because ozone is not a local phenomenon but is formed and transported over hundreds of miles and several days, localized control strategies will not be effective in reducing ozone levels. The bill, thus, expands the size of areas that are defined as ozone nonattainment areas to assure that controls are implemented in an area wide enough to address the problem." The 1990 FCAA Amendments did provide the ability to exclude portions of the entire MSA or CMSA prior to designation, if the state conducted a study, to which the EPA agreed, that proved the geographic portion did not contribute significantly to violation of the NAAQS.

Redesignation has not occurred for any portion of the HGA nonattainment area, and is not currently being considered. For existing areas currently included within a nonattainment area, the specific area must be redesignated as attainment in order to be removed from a nonattainment area. The FCAA, §107(d)(3) provides that the EPA may not redesignate a nonattainment area, or a portion of a nonattainment area, to attainment unless several criteria are met. These criteria include: a determination that the area has attained the NAAQS; there is a fully approved SIP for the area; there is a determination that the improvement in air quality is due to permanent and enforceable emissions reductions; there is an approved maintenance plan for the area; and the state has met all requirements for the area under FCAA, §110 and Part D.

However, even if a specific area within the HGA nonattainment area was redesignated by the EPA as attainment for ozone, reductions associated from all adopted ozone control strategies would still be necessary, because of the requirements of FCAA, §107(d)(3) and §175A which require maintenance plans for all redesignated areas. The maintenance plan must include the measures specified in §107(d)(3) and any additional measures that are necessary to ensure that the area continues to be in attainment with the NAAQS for ten years after the redesignation. Eight years after the redesignation, the state is required to submit an additional SIP revision to maintain the NAAQS for another ten years after the end of the first ten-year period.

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies.

At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on localized controls. However, for many years an ever 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, due to high levels of ozone and ozone precursor entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The commission has conducted air quality modeling and upper air monitoring that found regional air pollution should be considered when studying air quality in the Texas ozone nonattainment areas. This work is supported by research conducted by the OTAG, the most comprehensive attempt ever undertaken to understand and quantify the transport of ozone. Both the commission and the OTAG study point to the need to take a regional approach to controlling air pollutants.

Pre-trip Inspection and Cold Weather Operations

Sierra-Houston commented that they oppose the exemption in §114.507(6) which allows idling for defrosting a windshield. Metro commented that more than five minutes of idling time is required to perform a pre-trip inspection to examine all operational and safety aspects of the vehicle prior to operation. Metro also commented that when extremely cold overnight temperatures occur, heavy-duty diesels require additional start-up assistance from mechanics and warm-up time to assure that engines have reached appropriate operating temperatures and that braking, heating, and defrosting systems are functional.

The commission considers exemption §114.507(6) necessary for safety considerations. Idling of a motor vehicle that is being operated for maintenance or diagnostic purposes is allowed under the exemption in §114.507(5). If after the "pre-trip inspection" idle period the windshield is not fully defrosted, then the exemption in §114.507(6) would apply. Additionally, the commission added the exemption language in §114.507(7) that includes a maximum 30-minute idling period for transit operations and commercial passenger transportation vehicles when operating to supply heat or air conditioning for passenger comfort/safety.

Exempt Transit Service Vehicles

Metro commented that they feel the transit services industry should be exempt from the idling restrictions. Placing such strict guidelines on transit operations could negate the emissions benefits already realized by offering a viable alternative to driving a personal vehicle. Metro pointed out several situations or circumstances when a five-minute idle period is simply not sufficient: 1) cooling of suburban-route buses prior to the afternoon commute; 2) end-of-line layovers to maintain schedules when riders stay aboard; 3) transit center/park-and-ride dwell periods while loading and unloading passengers; and 4) bus breakdowns that require keeping the bus cool for stranded passengers while assistance is being coordinated.

The commission agrees that transit service is already an important part of the solution to reducing vehicle miles traveled and the accompanying traffic congestion and exhaust emissions. As such, the commission added language in §114.507(7) that includes a maximum 30-minute idling period for transit operations and commercial passenger transportation vehicles when operating to supply heat or air conditioning for passenger comfort/safety.

Calculations in Preamble

TCC questioned the numbers used to calculate the savings due to reduced fuel consumption as a result of the idling restrictions. TCC specifically questioned the preamble where it stated that two five- minute idle periods per day will result in 88 hours (and thus 88 gallons of fuel) saved during a year. Pony Pack commented that the commission mentioned in the preamble that "heavy-duty diesel and gasoline powered vehicles can consume up to one gallon of fuel per hour while idling." Pony Pack stated that this number should be between one and two gallons per hour.

The modeling for the idling restrictions was estimated by first determining the estimated baseline idle time for all affected vehicles in the HGA nonattainment area. Then the two assumed five-minute idle periods were subtracted from the baseline to determine with the estimated excess idle time that would be eliminated by the idling restriction rules. This "eliminated idle time" was converted to total hours per day for all affected vehicles. The commission used a national estimate (*Fleet Owner* - August 1998 and *Caterpillar Truck Engine News* - February 1993) of one gallon per hour fuel use to arrive at the total gallons of fuel saved per year. The calculations are explained in more detail in Appendix J of the HGA Post- 1999 ROP/Attainment Demonstration SIP. The commission made no changes to the rule language in response to this comment.

Texas Transportation Code (TTC) Cited in Definitions §114.500(2)

TCC commented they preferred that the commission include the text of provisions found in TTC, §502.002 and §502.006(c), instead of simply citing the provisions.

The commission disagrees that it is more clear to include the full text of TTC, §502.002 and §502.006(c) in the preamble or rule. These statutory provisions are readily available on the internet. The commission website and other general state government websites provide general access to state directories which include all state statutes and rules.

100% Compliance

Sierra-Houston and PIC commented that the rules' emissions reductions and cost savings used an unrealistic 100% compliance rate.

The commission agrees with this comment. The emissions reductions were remodeled using an 80% compliance rate, which is a rate normally used by the EPA for rulemakings. The preamble was corrected to reflect the new emissions reductions and cost savings figures.

Provide Flexibility by Including a Provision to Allow Submission of Alternative Reduction Plan

Metro, PHA, BCCA, Phillips 66, REI, and WM commented that a provision to submit an alternative reduction plan be included in the rule allowing those affected by the idling restrictions some flexibility.

The commission anticipates that due to the complexity and diversity of the community affected by the idling restrictions, allowing the submission of alternative reduction plans would result in unreasonable workloads for agency staff to track and evaluate the program, and would make enforcement against individual vehicles difficult. The commission made no changes to the rule language in response to this comment.

STATUTORY AUTHORITY

The new sections are adopted under TWC, §5.103, which authorizes the commission to adopt rules necessary to carry out its powers and duties under the TWC, and under the Texas Health and Safety Code, TCAA, §382.017, which provides the commission authority to adopt rules consistent with the policy and purposes of the TCAA. The new sections are also adopted under TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.019, which authorizes the commission to adopt rules to control and reduce emissions from engines used to propel land vehicles; and §382.039, which authorizes the commission to develop and implement transportation programs and other measures necessary to demonstrate attainment and protect the public from exposure to hazardous air contaminants from motor vehicles.

§114.500. Definitions.

Unless specifically defined in the TCAA or in the rules of the commission, the terms used in this subchapter have the meanings commonly ascribed to them in the field of air pollution control. In addition to the terms which are defined by the TCAA, §3.2 of this title (relating to Definitions); §101.1 of this title (relating to Definitions); and §114.1 of this title (relating to Definitions), the following words and terms, when used in this subchapter shall have the following meanings, unless the context clearly indicates otherwise.

(1) Idle - The operation of an engine in the operating mode where the engine is not engaged in gear, where the engine operates at a speed at the revolutions per minute specified by the engine or vehicle manufacturer for when the accelerator is fully released, and there is no load on the engine.

(2) Motor vehicle - Any self-propelled device powered by an internal combustion engine and designed to operate with four or more wheels in contact with the ground, in or by which a person or property is or may be transported, and is required to be registered under Texas Transportation Code (TTC), §502.002, excluding vehicles registered under TTC, §502.006(c).

(3) Primary propulsion engine - A gasoline or diesel-fueled internal combustion engine attached to a motor vehicle that provides the power to propel the motor vehicle into and maintain motion.

§114.507. Exemptions.

The provisions of §114.502 of this title (relating to Control Requirements for Motor Vehicle Idling) shall not apply to:

(1) a motor vehicle that has a gross vehicle weight rating of 14,000 pounds or less;

(2) a motor vehicle forced to remain motionless because of traffic conditions over which the operator has no control;

(3) a motor vehicle being used as an emergency or law enforcement motor vehicle;

(4) the primary propulsion engine of a motor vehicle providing a power source necessary for mechanical operation other than propulsion, passenger compartment heating or air conditioning;

(5) the primary propulsion engine of a motor vehicle being operated for maintenance or diagnostic purposes;

(6) the primary propulsion engine of a motor vehicle being operated solely to defrost a windshield;

(7) the primary propulsion engine of a motor vehicle that is being used to supply heat or air conditioning necessary for passenger comfort/safety in those vehicles intended for commercial passenger transportation or school buses in which case idling up to a maximum of 30 minutes is allowed;

(8) the primary propulsion engine of a motor vehicle used for transit operations in which case idling up to a maximum of 30 minutes is allowed; or

(9) the primary propulsion engine of a motor vehicle being used as airport ground support equipment.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009097
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

CHAPTER 115. CONTROL OF AIR POLLUTION FROM VOLATILE ORGANIC COMPOUNDS

The Texas Natural Resource Conservation Commission (TNRCC or commission) adopts amendments to §§115.161, 115.162, 115.164 - 115.167, and 115.169, concerning Batch Processes; §§115.122, 115.125 - 115.127, and 115.129, concerning Vent Gas Control; and §115.449, concerning Offset Lithographic Printing. The commission adopts these revisions to Chapter 115, concerning Control of Air Pollution from Volatile Organic Compounds, and to the state implementation plan (SIP) in order to conform with the United States Environmental Protection Agency's (EPA) reasonably available control technology (RACT) requirements in the Houston/ Galveston (HGA) ozone nonattainment area and to obtain volatile organic compound (VOC) emission reductions which will result in reductions in ozone formation in HGA. In an effort to improve implementation of the existing Chapter 115, the commission also adopts amendments to §115.10, concerning Definitions; and §§115.211, 115.212, and 115.216, concerning Loading and Unloading of Volatile Organic Compounds; new §115.120, concerning Vent Gas Definitions; §115.240, concerning Stage II Vapor Recovery Definitions; and §115.430, concerning Flexographic and Rotogravure Printing Definitions; and corresponding revisions to the SIP. Sections 115.10, 115.122, 115.125, 115.126, 115.129, 115.162, and 115.212 are adopted *with changes* to the proposed text as published in the August 25, 2000, issue of the *Texas Register* (25 TexReg 8253). Sections 115.120, 115.127, 115.161, 115.164 - 115.167, 115.169, 115.211, 115.216, 115.240, 115.430, and 115.449 are adopted *without changes* and will not be republished.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

The HGA ozone nonattainment area is classified as Severe-17 under the Federal Clean Air Act (FCAA), 1990 Amendments, (42 United States Code (USC), §§7401 et seq.), and therefore is required to attain the one-hour ozone standard of 0.12 parts per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined by Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties, has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of its Post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base case episodes, adopted rules to achieve a 9% rate-of-progress (ROP) reduction in VOC, and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary nitrogen oxides (NO_x) waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base case episodes which marginally exhibited model performance in accordance with EPA modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data- gathering exercise known as the Coastal Oxidant Assessment for Southeast Texas (COAST) study. The commission believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, EPA policy regarding SIP elements and timelines went through changes. Two national programs in particular resulted in changing deadlines and requirements. The first of these programs was the Ozone Transport Assessment Group (OTAG). This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in this study, and it has been concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that has impacted the SIP planning process is the revision to the national ozone standard. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, the EPA proposed an interim implementation plan (IIP) that it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development timelines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, that standard would continue to apply until it is attained. The FCAA requires that HGA attain the one-hour standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998 a revision to the HGA SIP which contained the following elements in response to EPA's guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by Subpart 2 of Title I of the FCAA to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the commission eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs as well as an acceleration simulation mode equivalent motor vehicle inspection and maintenance program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory state-wide programs adopted or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon Scenario VIf); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review; and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-99 ROP plan by December 31, 2000; to perform a mid- course review by May 1, 2004; and to perform modeling of mobile source emissions using the EPA mobile source emissions model (MOBILE6), to revise the on-road mobile source budget as needed, and to submit the revised budget within 24 months of the model's release. In addition, if a conformity analysis is to be performed between 12 months and 24 months after the MOBILE6 release, the state will revise the motor vehicle emissions budget (MVEB) so that the conformity analysis and the SIP MVEB are calculated on the same basis.

The emission reduction requirements included as part of this SIP revision represent substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, have worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area have formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

Reductions associated with the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies. At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The current SIP revision contains rules, enforceable commitments, photochemical modeling analyses, and calculation of the remaining NO_x reductions required to reach attainment (gap calculation) in support of the HGA ozone attainment demonstration. In addition, this SIP contains Post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contains enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit a mid- course review. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000 and planned to be submitted to the EPA by December 31, 2000.

In order for the state to have an approvable attainment demonstration, EPA has indicated that the state must adopt those strategies modeled in the November 15, 1999 submittal and then adopt sufficient controls to close the remaining gap in NO_x emissions. The Houston nonattainment area will need to ultimately reduce NO_x more than 750 tons per day (tpd) to reach attainment with the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of VOC RACT rules will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area.

Under 42 USC, §7511b of the 1990 Amendments to the FCAA, the EPA is required to issue Control Techniques Guideline (CTG) guidance documents for the purpose of assisting states in developing RACT controls for sources of VOC emissions. In turn, each state is required to submit a revision to its SIP which implements RACT regulations for VOC sources in moderate or above ozone nonattainment areas. Specifically, FCAA, 42 USC, §7511a(b)(2)(A), requires states to submit RACT regulations for VOC sources that are covered by a CTG issued after November 15, 1990 (the enactment date of the 1990 FCAA), but prior to the time of attainment. Similarly, FCAA, 42 USC, §7511a(b)(2)(C), requires that RACT be applied to major VOC sources located in moderate or above ozone nonattainment areas which are not the subject of a CTG; such sources are known as "non- CTG" sources. Limits in state rules must be at least as stringent as the CTG limits or otherwise must be determined to meet RACT.

Each CTG contains a "presumptive norm" for RACT for a specific source category, based on the EPA's evaluation of the capabilities and problems general to that category. Where applicable, the EPA recommends that states adopt requirements consistent with the presumptive norm. However, the presumptive norm is only a recommendation. States may choose to develop their own RACT requirements on a case-by-case basis, considering the emission reductions needed to obtain achievement of the national ambient air quality standards (NAAQS) and the economic and technical circumstances of the individual source.

Source categories for which the EPA was to issue CTGs under FCAA, 42 USC, §7511a(b)(2)(A), include batch processes and offset lithographic printing. Instead of issuing CTGs for these source categories, the EPA issued guidance documents known as Alternative Control Techniques (ACT) documents. An ACT does not establish the presumptive norm for RACT but merely contains information on emissions, controls, control options, and costs. The EPA itself has consistently noted in the ACT documents that each ACT "...presents options only, and does not contain a recommendation on RACT." Although the EPA has not issued the required CTGs for batch processes and offset lithographic printing, 42 USC, §7511a(b)(2)(C) of the 1990 FCAA Amendments still requires states to ensure that RACT is in place for all major VOC sources in moderate and above ozone nonattainment areas.

Historically, the commission's position has been that the existing general vent gas rule in Chapter 115, Subchapter B: Division 2 is adequate to ensure RACT for batch processes; however, this is difficult to demonstrate because the necessary information for such a demonstration is not in the emissions inventory (EI). Staff attempted to develop a demonstration of equivalency between the existing general vent gas rule and the batch processes ACT using the EPA's 5% rule. The EPA's "5% rule" provides a mechanism for states to justify exemptions or cutpoints which are more lenient than the EPA's RACT baseline. It is applied by determining the total emissions allowed by the EPA's RACT baseline (including exemptions) and comparing this to the emissions allowed (including exemptions) by a state regulation. If the difference is less than 5.0%, the EPA considers that there is no substantive difference between the EPA and state requirements. The staff was unable to assemble the information necessary to demonstrate to the EPA's satisfaction that existing rules represent RACT for batch processes in HGA because some of the necessary information is known only by the affected industry sources. Consequently, it is necessary to adopt and implement Chapter 115 rules for batch processes in HGA.

Bakeries are a non-CTG source category. The EPA published an ACT guidance document detailing appropriate control technology for bakeries. Based on this document, as well as on input from the bakery industry, the commission developed the applicable portion of the Chapter 115 vent gas rule pertaining to bakeries.

The EPA has stated that the existing vent gas rule is deficient in implementing RACT for bakeries and therefore is unapprovable. The EPA has made it clear that failure to correct the deficiencies will result in undesirable consequences for the affected ozone nonattainment areas, as specified in the FCAA. The commission adopted revisions on February 24, 1999 which address deficiencies in the bakery rule as it applies in the Dallas/Fort Worth (DFW) ozone nonattainment area. (See the March 12, 1999 issue of the *Texas Register* (24 TexReg 1777)). However, deficiencies in the bakery rule as it applies in HGA must be corrected for the HGA Attainment Demonstration SIP to be approvable. Specifically, the EPA has specified that RACT for bakery ovens is 80 - 90% control efficiency, while the commission rule as negotiated in 1994 requires only a 30% emission reduction.

The Chapter 115 offset lithographic printing rule (§§115.440, 115.442, 115.443, 115.445, 115.446, and 115.449) is currently a contingency rule for HGA. Because HGA is a severe ozone nonattainment area, a source in HGA is major if it has the potential to emit 25 tons per year (tpy) or more of VOC emissions. FCAA, 42 USC, §7511a(b)(2), requires that RACT be applied to major sources, and consequently it is necessary to implement this rule in HGA for sources with VOC emissions equal to or greater than 25 tpy. The rule will remain a contingency rule for offset lithographic printers in HGA with VOC emissions below 25 tpy. The offset lithographic printers in HGA with VOC emissions below 25 tpy must still comply with the general vent gas rules in Chapter 115.

SECTION BY SECTION DISCUSSION

The amendments to §115.10, concerning Definitions, delete the definitions of bakery oven, synthetic organic chemical manufacturing industry batch distillation operation, synthetic organic chemical manufacturing industry batch process, synthetic organic chemical manufacturing industry distillation operation, synthetic organic chemical manufacturing industry distillation unit, and synthetic organic chemical manufacturing industry reactor process. These terms are used solely within the Chapter 115 vent gas rules (§§115.121 - 115.123, 115.125 - 115.127, and 115.129) and are being concurrently relocated to a new §115.120, concerning Vent Gas Definitions.

The amendments to §115.10 also delete the definitions of independent small business marketer of gasoline, and owner or operator of a motor vehicle fuel dispensing facility. These terms are used solely within the Chapter 115 Stage II vapor recovery rules (§§115.241 - 115.249) and are being concurrently relocated to a new §115.240, concerning Stage II Vapor Recovery Definitions.

In addition, the amendments to §115.10 delete the definitions of flexographic printing process, packaging rotogravure printing, publication rotogravure printing, and rotogravure printing. These terms are used solely within the Chapter 115 flexographic and rotogravure printing rules (§§115.432, 115.433, 115.435 - 115.437, and 115.439) and are being concurrently relocated to a new §115.430, concerning Flexographic and Rotogravure Printing Definitions.

The amendments to §115.10 also delete the definitions of flare and vapor combustor. The definitions of these terms in §115.10 have been superceded by the corresponding definitions of these terms in 30 TAC §101.1, concerning Definitions. (See the December 17, 1999 issue of the *Texas Register* (24 TexReg 11494)). The commission added the definitions of flare and vapor combustor to §115.10 on June 30, 1999 as placeholders until definitions of these terms could be added to §101.1. (See the July 16, 1999 issue of the *Texas Register* (24 TexReg 5488)).

In addition, the amendments to §115.10 delete the definition of vapor recovery system and combine it with the definition of vapor control system. The existing definitions of vapor recovery system and vapor control system are identical, and the commission is in the process of a transition in the Chapter 115 rules to the term "vapor control system" from the misleading term "vapor recovery system," which is defined to include both recovery and combustion control devices. Combining both terms under the definition of vapor control system will facilitate this transition.

The amendments to §115.10 also revise the definitions of external floating roof and internal floating cover to more clearly specify that an external floating roof storage tank which is equipped with a self-supporting fixed roof (typically a bolted aluminum geodesic dome) is considered to be an internal floating roof storage tank for the purposes of Chapter 115 only.

In addition, the amendments to §115.10 add a definition of incinerator because the definition of this term in §101.1 specifically refers to devices used to combust solid or liquid materials. However, the term "incinerator," when used throughout Chapter 115, refers to control devices used to combust VOC vapors. The new definition will clarify the meaning of this term as used in Chapter 115. Subsequent definitions in §115.10 were renumbered due to the addition of the definition of incinerator.

The amendments to §115.10 also add a definition of liquefied petroleum gas in order to clarify the exemptions in §115.217(a)(3) and (b)(4) for loading and unloading of liquefied petroleum gas. Before the commission adopted revisions on June 30, 1999 (effective date: July 21, 1999), the previous versions of these exemptions referred to the safety rules of the Liquefied Petroleum Gas Division of the Texas Railroad Commission (RRC), which regulates many aspects of the handling and transport of liquefied petroleum gas. Because these exemptions historically referred to the RRC rules, it follows logically that the term "liquified petroleum gas" was intended to have the same meaning as defined in those RRC rules (specifically, 16 TAC §9.2(32), effective March 2, 1998). The National Fire Protection Association, which develops and publishes fire codes and safety standards, has a definition of liquefied petroleum gas in *Standard 58 - Standard for the Storage and Handling of Liquefied Petroleum Gases* which is functionally identical to the RRC's definition. Furthermore, Section 3-1 of the *Petroleum Products Handbook*, First Edition (Virgil B. Guthrie, editor), states that this is the most commonly used definition of liquefied petroleum gas. Therefore, the adopted definition of liquefied petroleum gas is consistent with other Texas state rules and industrial reference materials.

In addition, the amendments to §115.10 revise the definition of polymer and resin manufacturing process by replacing the "and" with "or" to make it clear that a manufacturing process only has to manufacture a listed polymer or a listed resin, but not both, in order to meet the definition. This amendment will make the definition consistent with the usage of this definition in the fugitive monitoring rules for ozone nonattainment areas (§§115.352 - 115.357 and 115.359).

The amendments to §115.10 also revise the definition of synthetic organic chemical manufacturing process by replacing the reference to Table I (Synthetic Organic Chemicals) with a reference to 40 Code of Federal Regulations (CFR) 60.489 (effective October 18, 1983). Concurrently, Table I is being deleted. The list of affected chemicals is unchanged because Table I was derived from the corresponding table in 40 CFR 60.489.

Finally, the amendments to §115.10 revise the definition of transport vessel to delete the ambiguous term "primarily." The revision will clearly specify that a transport vessel includes any land-based mode of transportation (truck or rail) of oil, gasoline, or other volatile organic liquid bulk cargo in a storage tank which has a capacity greater than 1,000 gallons. This has always been the interpretation of the term "transport vessel," so this revision simply makes that interpretation more clear.

The new §115.120, concerning Vent Gas Definitions, adds definitions of bakery oven, synthetic organic chemical manufacturing industry batch distillation operation, synthetic organic chemical manufacturing industry batch process, synthetic organic chemical manufacturing industry distillation operation, synthetic organic chemical manufacturing industry distillation unit, and synthetic organic chemical manufacturing industry reactor process. These definitions are being concurrently relocated from the §115.10, concerning Definitions, because they are used solely within the Chapter 115 vent gas rules (§§115.121 - 115.123, 115.125 - 115.127, and 115.129).

The amendments to §115.122, concerning Control Requirements, change the 30% emission reduction requirement from the 1990 baseline EI for major source bakeries in HGA to an 80% emission reduction requirement from the uncontrolled VOC emission rate of the oven(s) and establish a December 31, 2001 compliance date. The amendments to §115.122 also change the baseline for major source bakeries in the DFW ozone nonattainment area from the 1990 baseline EI to the uncontrolled VOC emission rate of the oven(s). In addition, the amendments to §115.122 update rule cross-references; update references from "standard exemption" to "permit by rule" due to the requirements of Senate Bill (SB) 766, which amended the Texas Clean Air Act (TCAA) and created "permits by rule;" change references from "Centigrade" to "Celsius" since this is now the term commonly used to describe this temperature scale; and change references from "vapor recovery system" to "vapor control system" for clarification. Finally, the amendments to §115.122(a)(3)(E) change a reference from "§101.29 of this title (relating to Emissions Credit Banking and Trading)" to "Chapter 101, Subchapter H, Division 1 of this title (relating to Emission Credit Banking and Trading)" due to the repeal of

§101.29 and its relocation to a new division within Chapter 101 in concurrent rulemaking published elsewhere in this issue of the *Texas Register*.

The amendments to §115.125, concerning Testing Requirements, extend the existing test methods to Aransas, Bexar, Calhoun, Matagorda, San Patricio, and Travis Counties; consolidate the existing §115.125(a) and (b) into a single subsection; reorganize the section by grouping related test methods together; and clarify that the test methods and procedures are to be used when testing is specifically required within this division (Vent Gas Control), when the executive director requests testing under §101.8 (Sampling), or when the owner or operator chooses to conduct testing of one or more vent gas streams.

Because it is not reasonably possible to measure the mass emission rate from an elevated flare (an elevated flare's flame is open to the atmosphere, such that the emissions cannot be routed through a stack), the test methods for flow rate and VOC concentration in the existing §115.125(a)(3) - (6) and (b)(3) - (6), which are renumbered as §115.125(1) and (2), do not apply to flares. In order to specify performance requirements for flares, the revisions to new §115.125(3) establish the test requirements of 40 CFR 60.18(b) for flares in the Beaumont/Port Arthur (BPA), DFW, and HGA ozone nonattainment areas. Because flares cannot be stack-tested, the amendments to §115.125(3) also specify that compliance with the requirements of 40 CFR 60.18(b) represents compliance with the emission specifications of §115.121 and the control efficiency requirements of §115.122. The revisions to §115.125(3) also take into account situations in which a flare operates under a waiver from testing according to 40 CFR 60.18.

In addition, the amendments to §115.125 include an option that the owner or operator of a vapor combustor may consider it to be a flare. Each vapor combustor in Victoria County and the BPA, DFW, El Paso (ELP), and HGA areas which the owner or operator elects to consider as a flare shall meet the performance test requirements of 40 CFR 60.18(b) in lieu of any testing under §115.125(1) and (2) for a thermal or catalytic oxidizer. The amendments to §115.125 also add a new paragraph (5), which authorizes the use of test methods other than those specifically listed in §115.125, provided that any new test method is validated using the procedures in 40 CFR 63, Appendix A, Test Method 301, with the executive director acting as the administrator. This revision is necessary because in some specific unique situations, the listed test methods may be inappropriate. The new paragraph (5) increases flexibility by allowing the use of additional test methods which may be more cost-effective and more appropriate in certain unique situations. The changes to §115.125 do not add any requirements to Aransas, Bexar, Calhoun, Matagorda, Nueces, San Patricio, and Travis Counties.

Previously, §115.126 did not include specific recordkeeping requirements for vent gas sources in Aransas, Bexar, Calhoun, Matagorda, San Patricio, and Travis Counties. The amendments to §115.126, concerning Monitoring and Recordkeeping Requirements, add recordkeeping requirements in these counties which are sufficient to document compliance with the exemptions, but do not add any continuous monitoring requirements to these counties. In addition, the amendments to §115.126 consolidate the existing §115.126(a) and (b) into a single subsection; update references to other sections; replace "true partial pressure" with the more understandable term "concentration;" revise §115.126(4) to allow use of engineering calculations to document that a vent gas stream is below the applicable exemption limits at maximum operating conditions; and add new §115.126(3)(D) and (E) for consistency with the exemptions available in §115.127(a)(4)(B) and (C).

The amendments to §115.126 also change the 30% emission reduction requirement from the 1990 baseline EI for major source bakeries in HGA to an 80% emission reduction requirement from the uncontrolled VOC emission rate of the oven(s), establish a December 31, 2001 compliance date, and require submittal of a control plan by March 31, 2001 which shows how the owner or operator will meet the emission reduction requirements. In addition, the amendments to §115.126 change the baseline for major source bakeries in DFW from the 1990 EI to the uncontrolled VOC emission rate of the oven(s), and delete the annual reporting requirements for major source bakeries in DFW and HGA. Because the major source bakeries in DFW and HGA have installed (or are in the process of installing) catalytic oxidizers which can readily meet the control requirements and the monitoring and recordkeeping requirements will ensure that these control devices are functioning properly, there is no need for these bakeries to submit an annual report.

Finally, the amendments to §115.126 also specify that flares in BPA, DFW, and HGA must meet the requirements of 40 CFR 60.18(b) and Chapter 111; and state that records of appropriate operating parameters must be kept for types of vapor control systems not specifically listed in §115.126(1)(A) and (B). Section 115.126(1)(A)(iv) and (B) specify exhaust gas temperature monitoring of vapor combustors in Victoria County, BPA, DFW, ELP, and HGA, with an option that the owner or operator of a vapor combustor may consider it to be a flare and monitor the unit under the flare requirements specified in 40 CFR 60.18(b) and 30 TAC Chapter 111. These amendments are necessary to ensure that control devices are functioning properly and to clarify how vapor combustors are to be monitored.

Based upon information from the Air Permits Division, most existing flares meet the design and operating criteria of 40 CFR 60.18(b). The commission solicited information regarding vents in BPA, DFW, and HGA which are controlled by flares that do not meet the requirements of 40 CFR 60.18(b). In response, the commission received a comment that some flares operate under a waiver from testing according to 40 CFR 60.18. Comments received during the comment period regarding flares that operate under a waiver from testing according to 40 CFR 60.18 are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

Sources which are addressed by a Chapter 115 contingency rule (i.e., one in which Chapter 115 requirements are triggered for that source by the commission publishing notification in the *Texas Register* that implementation of the contingency rule is necessary) are subject to the requirements of Division 2, concerning Vent Gas Control, until the compliance date of that contingency rule. The purpose is to ensure that a Chapter 115 rule (either the general vent gas rule or the more specific contingency rule, but not both) applies at all times to sources addressed by a contingency rule. The amendments to §115.127(a) add a new paragraph (8) which specifies that for a source that is addressed by a Chapter 115 contingency rule, the owner or operator of that source may choose to comply with the requirements of the contingency rule as though the contingency rule already had been implemented for that source, rather than complying with Division 2. In the case of bakeries, this option would be an alternative to complying with the general vent gas control requirements of

§115.121(a)(1) and §115.122(a)(1) because these currently applicable requirements are in the same division (Division 2, concerning Vent Gas Control), as the bakery contingency measure requirements.

For example, under §115.449(c) the offset printing rules of §§115.442 - 115.446 are a contingency rule for each printing operation in DFW for which all offset lithographic printing presses on a property, when uncontrolled, emit a combined weight of VOC less than 50 tons per calendar year. Such sources are currently subject to the requirements of Division 2, concerning Vent Gas Control. Under the new §115.127(a)(8), the owner or operator of such a printing operation instead has the option of complying with the offset printing rules of §§115.442 - 115.446 as though that offset printing contingency rule had been implemented in DFW and the compliance date had already passed.

In addition, the amendments to §115.127 delete the concentration thresholds in true partial pressure and retain the more understandable concentration thresholds in parts per million by volume (ppmv).

The amendments to §115.129, concerning Counties and Compliance Schedules, specify the compliance schedule for the new requirements described earlier in this preamble; delete language which is obsolete due to the passing of the May 31, 1996 and November 15, 1996 compliance dates; and update references to other sections.

The rule amendments add the Chapter 115 batch process requirements (§§115.160 - 115.167 and 115.169) to the eight-county HGA ozone nonattainment area. The rule language is based upon the EPA's *Control of Volatile Organic Compound Emissions from Batch Processes - Alternative Control Techniques Information Document* (EPA-453/R-94-020, February 1994).

The amendments to §115.161, concerning Applicability, specify that the batch process requirements of §§115.162 - 115.167 apply to vent gas streams at batch process operations in the HGA area under the Standard Industrial Classification (SIC) codes 2821 (plastic resins and materials), 2833 (medicinals and botanicals), 2834 (pharmaceutical preparations), 2861 (gum and wood chemicals), 2865 (cyclic crudes and intermediates), 2869 (industrial organic chemicals, not elsewhere classified), and 2879 (agricultural chemicals, not elsewhere classified).

The amendments to §115.161 also specify that the existing requirements of Subchapter B, Division 2, concerning Vent Gas Control, will continue to apply to batch process operations in HGA which are exempt from §§115.162 - 115.166 because they are located at an account which has total VOC emissions (determined before control but after the last recovery device) of less than 25 tpy from all stationary emission sources at the account.

The amendments to §115.162, concerning Control Requirements, make batch process operations in HGA subject to: the applicable RACT equations for low, moderate, and high volatility materials; a successive ranking scheme which determines which sources must be controlled and which are exempt; and the EPA's "once-in, always-in" (OIAI) requirement. OIAI is an EPA concept which means that once emissions from a source exceed the applicability cutoff for a particular VOC regulation in the SIP, that source is always subject to the control requirements of the regulation. In addition, the amendments to §115.162 update references from "standard exemption" to "permit by rule" due to the requirements of SB 766, which amended the TCAA and created "permits by rule."

Although no amendments were proposed to §115.163, concerning Alternate Control Requirements, an alternate means of control is available under this section for batch process operations in HGA.

The amendments to §115.164, concerning Determination of Emissions and Flow Rates, make batch process operations in HGA subject to the procedures for determining the uncontrolled annual emission total and the average flow rate for process vents.

The amendments to §115.165, concerning Approved Test Methods and Testing Requirements, make batch process operations in HGA subject to specified test methods and testing requirements for determining compliance with the control requirements. Minor modifications to the test methods may be used if approved by the executive director.

Because it is not reasonably possible to measure the mass emission rate from an elevated flare (an elevated flare's flame is open to the atmosphere, such that the emissions cannot be routed through a stack), the test methods for flow rate and VOC concentration do not apply to flares. In order to specify performance requirements for flares, §115.165 includes the test requirements of 40 CFR 60.18(b). Because flares cannot be stack-tested, the §115.165 also specifies that compliance with the requirements of 40 CFR 60.18(b) represents a 98% control efficiency. Based upon information from the Air Permits Division, most existing flares meet the design and operating criteria of 40 CFR 60.18(b). The commission solicited information regarding flares which are used to control emissions from batch process operations in HGA, but do not meet the requirements of 40 CFR 60.18(b). All comments received during the comment period regarding flares are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

Section 115.165 also includes authorization for the use of test methods other than those specifically listed in §115.165, provided that any new test method is validated using the procedures in 40 CFR 63, Appendix A, Test Method 301, with the executive director acting as the administrator. This option is included in §115.165 because in some specific unique situations the listed test methods may be inappropriate. The availability of this option increases flexibility by allowing the use of additional test methods which may be more cost-effective and more appropriate in certain unique situations.

The amendments to §115.166, concerning Recordkeeping Requirements, make batch process operations in HGA subject to requirements for: continuous monitoring and recording of control device operating parameters; recordkeeping of the annual mass emission total, average flow rate, and associated documentation for each process vent; and the control device operating parameters to be measured and recorded during performance testing. The amendments also change an incorrect reference in §115.166(1) from "VOC transfer operations" to "batch process operations." As a result of this correction, the term "VOC" is being spelled out in §115.166(1)(A)(iii)(II).

The amendments to §115.167, concerning Exemptions, make the following exemptions available in HGA: batch process operations which are located at an account in HGA which has total VOC emissions (determined before control but after the last recovery device) of less than 25 tpy; single unit operations that have a mass annual emissions of 500 pounds per year or less; and combined vents from a batch process train which have a mass annual emissions total below specified levels which vary depending on the volatility of the VOCs. In addition, the amendments revise the existing exemption in §115.167(2) to clarify that §115.164, concerning Determination of Emissions and Flow Rates, is to be used for determining if the exemptions available under §115.167(2) are met. The amendments to §115.167 also specify that the existing requirements of Subchapter B, Division 2, concerning Vent Gas Control, will continue to apply to batch process operations which qualify for exemption because they are located at an account in HGA which has total VOC emissions (determined before control but after the last recovery device) of less than 25 tpy.

The amendments to §115.169, concerning Counties and Compliance Schedules, specify the newly affected counties in HGA (Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller) and a December 31, 2002 compliance date for the new requirements. The amendments to §115.169 also specify that batch process operations which are subject to the requirements of §§115.162 - 115.166 must continue to comply with the existing requirements of Subchapter B, Division 2, concerning Vent Gas Control, until these batch process operations are in compliance with the new requirements.

The amendments to §115.211, concerning Emission Specifications, delete a reference to gasoline bulk plants which is no longer necessary due to the deletion of the gasoline bulk plant emission specification adopted by the commission on November 10, 1999. (See the November 26, 1999 issue of the *Texas Register* (24 TexReg 10559)).

The amendments to §115.212, concerning Control Requirements, revise §115.212(a)(3) and (b)(3) to state that the requirements regarding vapor and liquid leaks during land-based VOC transfer apply specifically to transport vessels. This revision is necessary in order to clarify that the requirements are not intended to apply to vessels which do not meet the definition of "transport vessel" in §115.10 (for example, drums). In addition, the amendments to §115.212 update references from "standard exemption" to "permit by rule" due to the requirements of SB 766, which amended the TCAA and created "permits by rule."

The amendments to §115.216, concerning Monitoring and Recordkeeping Requirements, revise §115.216(3)(A)(i) to only require records of the identification number of tank-truck tanks for which annual leak testing is required under §115.214(a)(1)(C) or (b)(1)(C), rather than all tank-truck tanks as is currently required. This amendment is adopted because it is unnecessary to track the identification number of tank-truck tanks which are excluded from the annual leak testing requirements.

The new §115.240, concerning Stage II Vapor Recovery Definitions, adds definitions of independent small business marketer of gasoline, and owner or operator of a motor vehicle fuel dispensing facility. These definitions are being concurrently relocated from the §115.10, concerning Definitions, because they are used solely within the Chapter 115 Stage II vapor recovery rules (§§115.241 - 115.249).

The new §115.430, concerning Flexographic and Rotogravure Printing Definitions, adds definitions of flexographic printing process, packaging rotogravure printing, publication rotogravure printing, and rotogravure printing. These definitions are being concurrently relocated from the §115.10, concerning Definitions, because they are used solely within the Chapter 115 flexographic and rotogravure printing rules (§§115.432, 115.433, 115.435 - 115.437, and 115.439). In addition, the commission changed the title of Subchapter E, Division 3 from "Graphic Arts (Printing) by Rotogravure and Flexographic Processes" to "Flexographic and Rotogravure Printing" in order to more clearly specify the operations addressed by to this division.

HGA is classified as a severe ozone nonattainment area and the major source definition includes VOC sources with emissions of 25 tpy and higher. Because FCAA, 42 USC, §7511a(b)(2), requires that RACT be applied to major sources, the amendments to §115.449, concerning Counties and Compliance Schedules, implement the offset lithographic printing rule in HGA for sources with VOC emissions equal to or greater than 25 tpy and establishes a compliance date of December 31, 2002. The offset lithographic printing rule is currently a contingency rule for HGA; after the effective date of these amendments, the rule will be a contingency rule for offset lithographic printers in HGA with VOC emissions below 25 tpy.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMIT PROGRAM

Since Chapter 115 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 115 requirements for each emission unit affected by the revisions to Chapter 115 at their site.

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION

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 does not meet 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.

These adopted rules do not meet any of the four applicability criteria for requiring a regulatory analysis of "major environmental rule" as defined in the Texas Government Code. Section 2001.0225 applies only to a major environmental rule the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

As discussed earlier in this preamble, this rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000, and planned to be submitted to the EPA by December 31, 2000.

The amendments to Chapter 115 are one element of the HGA Attainment Demonstration SIP and will require VOC emission reductions from batch processes, offset lithographic printers, and bakeries in the HGA ozone nonattainment area. While the rules are intended to protect the environment, based on the analysis provided earlier in this preamble and in particular, the discussion in the FISCAL NOTE: COSTS TO STATE AND LOCAL GOVERNMENT and the PUBLIC BENEFIT AND COSTS sections in the rule proposal preamble (see the August 25, 2000 issue of the *Texas Register* (25 TexReg 8258)), the commission does not believe that the rules will adversely affect, in a material way, the operation of certain batch processes, offset lithographic printers, and bakeries. The commission does not believe these entities comprise a sector of the economy, or that these rules will adversely affect in a material way the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

The amendments do not meet the definition of a "major environmental rule" as defined in the Texas Government Code, and they do not meet any of the four applicability requirements listed in §2001.0225(a). Specifically, the rules do not exceed an express standard set by federal law since they implement requirements of the FCAA. Under 42 USC, §7410, states are required to adopt a SIP which provides for "implementation, maintenance, and enforcement" of the primary NAAQS in each air quality control region of the state. These rules were developed in order to meet FCAA, 42 USC, §7511a(b)(2)(C), which requires states to ensure that RACT is in place for all major VOC sources in moderate and above ozone nonattainment areas. This will enable the Chapter 115 batch process, offset lithographic printing, and bakery rules for HGA to be federally approvable. This rulemaking is also intended to obtain VOC emission reductions which will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under 42 USC, §7410. While 42 USC, §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 42 USC, Chapter 85, Air Pollution Prevention and Control). It is true that the FCAA does require some specific measures for SIP purposes, such as 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 42 USC, §7410. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commission's photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended to serve two purposes; one is to satisfy 42 USC, §7511a(b)(2)(C), and the second is to achieve reductions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA.

During the 75th Legislative Session, SB 633 amended the Texas Government Code to require agencies to perform a regulatory impact analysis (RIA) of certain rules. 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 earlier in this preamble, 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 proposes and 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.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

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. FCAA, 42 USC, §7511a(b)(2)(C), requires states to ensure that RACT is in place for all major VOC sources in moderate and above ozone nonattainment areas. This rulemaking is not an express requirement of state law, but was developed specifically in order to ensure that RACT is in place for all major VOC sources in the HGA ozone nonattainment area as required under federal law. This will enable the Chapter 115 batch process, offset lithographic printing, and bakery rules for HGA to be federally approvable. This rulemaking is also intended to obtain VOC emission reductions which will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. 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 RACT requirements and NAAQS established under federal law and authorized under TCAA, §§382.011, 382.012, and 382.017. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225. Comments received during the comment period regarding the draft RIA are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

TAKINGS IMPACT ASSESSMENT (TIA)

The commission evaluated this rulemaking action and performed an analysis of whether the rules are subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. The specific purpose of the rulemaking is twofold: to ensure that RACT is in place for all major VOC sources in the HGA ozone nonattainment area in order to conform with the EPA's RACT requirements, thus enabling the Chapter 115 batch process, offset lithographic printing, and bakery rules for HGA to be federally approvable; and to obtain VOC emission reductions which will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone.

Texas Government Code, §2007.003(b)(4), provides that Chapter 2007 does not apply to these adopted rules since they are reasonably taken to fulfill an obligation mandated by federal law. The rules fulfill federal mandates under the 1990 Amendments to 42 USC, §7410 and §7511a(b)(2). Specifically, 42 USC, §7511a(b)(2)(C), requires states to ensure that RACT is in place for all major VOC sources in moderate and above ozone nonattainment areas. In addition, the emission limitations and control requirements within this rulemaking were developed in order to meet the NAAQS for ozone set by the EPA under 42 USC, §7409. States are primarily responsible for ensuring attainment and maintenance of NAAQS once the EPA has established them. Under 42 USC, §7410, 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 ensure that RACT is in place for all major VOC sources in the HGA ozone nonattainment area as required under federal law and to meet the air quality standards established under federal law as NAAQS. Attainment of the ozone standard will eventually require substantial NO_x reductions as well as VOC reductions. Any VOC reductions resulting from the current rulemaking are no greater than what scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard.

In addition, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rule revisions 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 significantly advance the health and safety purpose. This action is taken in response to the HGA area exceeding the federal ambient air quality standard for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient VOC and ozone levels in HGA. Consequently, these rules meet the exemption in §2007.003(b)(13).

The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking therefore meets the requirements of Texas Government Code, §2007.003(b)(4) and (13). For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis. Comments received during the comment period regarding the TIA are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

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 VOC from batch process vent gas streams, bakeries, and offset lithographic printers. This action is consistent with the CMP because it does not authorize any new emissions and will reduce existing emissions of VOC. No comments were received during the comment period regarding the CMP consistency review.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000.

Forty-nine commenters submitted testimony on the proposal. Pasadena Paper Company LP, Pasadena Pulp Company LP, and Donohue Industries Incorporated submitted joint comments and will be referred to as Pasadena/Donohue. Chevron Phillips Chemical Company LP (Chevron); Dynegy, Incorporated (Dynegy); Dow Chemical Company (Dow); Enron; Equistar Chemicals LP (Equistar); ExxonMobil; Goodyear Rubber and Tire Company (Goodyear); Lyondell-Citgo Refining LP (LCR); Lyondell Chemical Company (Lyondell); Phillips 66 Company (Phillips 66); Reliant Energy, Incorporated (REI); and Valero Refining Company-Texas (Valero) supported the comments submitted by the Business Coalition for Clean Air (BCCA); therefore, references to BCCA will include references to these commenters. Chevron, Dow, Equistar, ExxonMobil, Lyondell, and Phillips 66 supported the comments submitted by the Texas Chemical Council (TCC); therefore, references to TCC will include references to these commenters. Pasadena/Donohue supported the comments submitted by the Texas Pulp and Paper Industry Environmental Council (TPIEC).

The League of Women Voters of Texas (LWV-TX) and nine individuals supported the proposed revisions, while Hispanic Community of Texas Citizens for a Sound Economy (TCSE-HC); RMT, Inc. on behalf of Montgomery County (Montgomery Co.); and three individuals opposed the proposed revisions. Baker Botts L.L.P. (Baker Botts); BCCA; Chevron; City of Missouri City (Missouri City); City of Spring Valley (Spring Valley); Dow; Dynegy; Enron; EPA; Equistar; ExxonMobil; Galveston- Houston Association for Smog Prevention (GHASP); Goodyear; Grandparents of East Harris County (GEHC); Harris County Judge Robert Eckels (Harris County); LCR; Lyondell; Pasadena/Donohue; Phillips 66; Printing Industries of the Gulf Coast (PIGC); REI; Sierra Club - Houston Regional Group (Sierra-Houston); State Senator Carlos Truan; TCC; TPIEC; Texas Oil and Gas Association (TxOGA); Union Carbide Corporation (Union Carbide); Valero; and six individuals supported the proposed revisions but suggested changes or clarifications.

ANALYSIS OF TESTIMONY

LWV-TX and nine individuals supported the proposed revisions to Chapter 115.

The commission appreciates the support.

One individual commented that the rules go beyond anything necessary to protect the environment, the basis and analysis in the rules is flawed, and the rules are being set up to embarrass Texas and the Governor, and the individual hopes that state legislators and the United States Congress would investigate these plans. The individual also commented that the TNRCC and the EPA should be downsized because less government is better than more government.

The commission does not agree that the rules are too broad or that the basis or analysis of the rules is flawed. Title 42 USC, §7511a(b)(2)(C), requires states to ensure that RACT is in place for all major VOC sources in moderate and above ozone nonattainment areas. As discussed earlier in the preamble, the EPA has stated that the existing Chapter 115 vent gas rules do not represent RACT for batch processes in HGA, and consequently it is necessary to implement the Chapter 115 batch process rules in HGA. In addition, the EPA has identified a variety of deficiencies in the existing Chapter 115 bakery rule for HGA. Finally, there are an estimated 20 major source offset printers in HGA for which RACT rules have not been implemented. Correction of these deficiencies is necessary to ensure the implementation of RACT in HGA such that these rules are federally approvable. Further, the adopted rules are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. Title 42 USC, §7410, 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. The commission's intent is not to embarrass Texas and the Governor but instead to comply with the timelines provided in 1990 FCAA amendments and subsequent EPA guidance for submitting rules to demonstrate ozone attainment in HGA. Accordingly, Texas has committed to adopting the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000.

GEHC and two individuals stated that facilities that predate the commission's air permitting requirements (i.e., those that are "grandfathered") should be subject to the emission specifications. GHASP commented that all grandfathered facilities should be investigated to be certain that they are properly so designated since many of these facilities have made modifications. State Senator Carlos Truan commented that a problem with the proposed rules is that they do not deal with grandfathered facilities and that the commission has let these facilities avoid permitting through the use of standard exemptions.

The commission has made no change in response to the comments. The adopted rules that apply to facilities, for example the Chapter 117 NO_x requirements and the Chapter 115 VOC requirements, apply to both permitted and non-permitted ("grandfathered") sources in HGA. The commission agrees that it is appropriate to pursue cost-effective measures to reduce pollution; however, any such measures must be within the statutory authority of the commission. The TCAA does not authorize the commission to require grandfathered sources to obtain permits in order to operate, or to prohibit operation of those sources. A grandfathered facility is one that existed at the time the Texas Legislature amended the TCAA in 1971. These facilities were not required to comply with (i.e., were grandfathered from) the then-new requirement to obtain permits for construction activities. Whenever a grandfathered facility is modified (as that term is defined in the TCAA), it is required to comply with the TCAA permitting requirements in order to be authorized to construct and operate that modification. If a grandfathered facility has never been modified, it continues to be authorized by the TCAA to operate without a permit. Further, the definition of "modification" specifically excludes changes to facilities that are authorized by an exemption; i.e., any facility, including a grandfathered facility, can make a change using a commission exemption (now permit by rule) and this change is not considered to be a modification that would trigger the permitting requirements of the TCAA. During the 76th Texas Legislative Session in 1999, the issue of grandfathered sources was addressed by two different legislative programs. SB 766 was passed, which provided a framework for a voluntary permitting program for grandfathered sources under the TCAA, as well as SB 7, which requires mandatory permitting and emission reductions from electric generating facilities. The commission continues to pursue enforcement action against companies who are not in compliance with the permitting requirements of the TCAA. However, SB 766 does provide for amnesty from enforcement for facilities eligible to participate in the voluntary emission reduction permit program as long as a permit application is received before the TCAA deadline of September 1, 2001.

Baker Botts commented that it generally supports the ongoing efforts by the commission to develop a SIP that is technologically achievable, economically reasonable, and legally approvable. Baker Botts, BCCA, Dynegy, Equistar, ExxonMobil, Goodyear, Harris County Judge Robert Eckels, Phillips 66, Spring Valley, TCC, TPIEC, TxOGA, Valero, and an individual commented that the commission should incorporate into the SIP a greater level of reductions from federally preempted sources and stated that EPA-regulated sources account for about 40% of the NO_x emissions in the HGA. The commenters stated that the EPA issued a number of regulations for some federally preempted sources, such as land-based spark engines, marine, recreational and land-based diesel engines, aircraft and locomotive engines, well after the FCAA deadlines, and that the EPA recently strengthened rules for on-road and non-road vehicles and fuels, such as low sulfur gas and diesel, Tier II motor vehicles, heavy-duty highway vehicle standards, and non-road Tier II/Tier III heavy-duty engine standards. The commenters stated that delays in implementing these rules have prompted the commission to propose technically and economically infeasible emission reductions from sources in HGA that the state has authority to regulate to make up for the missing federal reductions. The commenters stated that these delays have forced the commission to propose expensive regional fuels and significant use restriction regulations. The commenters stated that the commission and the EPA can ensure an equitable distribution of the compliance burdens necessary to meet mandated air quality improvement in HGA only by allowing the SIP to capture anticipated emission reductions from federally preempted sources. Baker Botts noted that the EPA demonstrated a willingness to assume responsibility for a portion of emission reductions by created a process in Los Angeles called a "public consultative process," that would resolve issues related to emissions from national and international sources, and that the EPA has also provided flexibility in obtaining offsets by allowing states to provide offsets to refiners based on emission reductions that the EPA projected would result from mobile sources using Tier II gasoline. Baker Botts suggested that this same sort of prospective crediting should be used to develop a more rational HGA SIP, and that the EPA should allow the commission to credit in the SIP the prospective emission reductions that will result from implementation of the Tier II gasoline rule and from other federally preempted sources. Finally, Baker Botts cited two cases wherein the District of Columbia Circuit has approved the EPA's flexibility with respect to statutory deadlines under the FCAA when the EPA has failed to meets its own deadlines, and this failure was deemed to upset the balanced federal/state responsibilities under the FCAA. ExxonMobil commented that it supports the commission and the EPA crediting the HGA SIP with an additional 60 tpd of federally preempted emission reductions that will occur over the next ten years. Harris County Judge Robert Eckels commented that the commission should work with the EPA to accelerate the implementation schedule for federally preempted emissions so that at least one-half of the related emission reductions are achieved by 2007, and that as a part of this process, the commission should delineate federal assignments detailing the engine standards and emission reductions necessary to achieve real and sustainable pollution reductions.

The commission agrees with the commenters that emission reductions from federally preempted sources would provide benefits for the HGA SIP demonstration, and the inability of the commission to regulate certain source categories has necessitated the use of other ozone control strategies. However, the commission understands that the EPA SIP approval process does not provide a mechanism for credit for emission reductions that occur after the attainment date. The commission understands that the EPA is not currently considering accelerating implementation schedules for existing federal rules. The commission is working with the EPA to determine the availability of SIP credit for many non- traditional control strategy mechanisms, like economic incentive programs and flexibility for preempted source categories. Additionally, the commission is working with the EPA to determine an appropriate federal contribution credit available for the HGA SIP.

TCSE-HC and two individuals opposed the proposed revisions to Chapter 115. Montgomery Co. opposed implementation of the proposed Chapter 115 revisions in Montgomery County, while an individual opposed implementation of the proposed Chapter 115 revisions in Chambers and Liberty Counties.

As noted earlier in this preamble, FCAA, 42 USC, §7511a(b)(2), requires implementation of RACT at major VOC sources located in moderate or above ozone nonattainment areas. The adopted rules satisfy this federal requirement and are necessary to ensure that the current SIP revision in support of the HGA ozone attainment demonstration will be federally approvable. Furthermore, the FCAA Amendments of 1990 provided new requirements for areas that had not attained the NAAQS for ozone, carbon monoxide, particulate matter, sulfur dioxide, nitrogen dioxide, and lead, and new requirements for SIPs in general. The EPA was authorized to designate areas failing to meet the NAAQS for ozone as nonattainment and to classify them according to severity. Section 107(d)(4)(A)(iv) of the FCAA mandated that areas designated as serious, severe, or extreme for ozone that were within a metropolitan statistical area (MSA) or consolidated metropolitan statistical area (CMSA) must have boundaries that include the entire MSA or CMSA. This requirement is supported by the legislative history for the FCAA Amendments in Senate Report No. 101-228, page 3399, "Because ozone is not a local phenomenon but is formed and transported over hundreds of miles and several days, localized control strategies will not be effective in reducing ozone levels. The bill, thus, expands the size of areas that are defined as ozone nonattainment areas to assure that controls are implemented in an area wide enough to address the problem." The FCAA Amendments did provide the ability to exclude portions of the entire MSA or CMSA prior to designation, if the state conducted a study that the EPA agreed proved that the geographic portion did not contribute significantly to violation of the NAAQS.

Redesignation has not occurred for any portion of the HGA nonattainment area, and is not currently being considered. For existing areas currently included within a nonattainment area, the specific area must be redesignated as attainment to be removed from a nonattainment area. FCAA, §107(d)(3), provides that the EPA may not redesignate a nonattainment area, or a portion thereof, to attainment unless several criteria are met, which include: a determination that the area has attained the NAAQS; there is a fully approved SIP for the area; there is a determination that the improvement in air quality is due to permanent and enforceable reductions in emissions; there is an approved maintenance plan for the area; and the state has met all requirements for the area under FCAA, §110 and Part D.

However, even if a specific area within the HGA nonattainment area was redesignated by the EPA as attainment for ozone, reductions associated from all adopted ozone control strategies would still be necessary because of the requirements of FCAA, §107(d)(3) and §175A, which require maintenance plans for all redesignated areas. The maintenance plan must include the measures specified in §107(d)(3) and any additional measures that are necessary to ensure that the area continues to be in attainment with the NAAQS for ten years after the redesignation. Eight years after the redesignation, the state is required to submit an additional revision to the SIP for maintaining the NAAQS for ten years after the end of the first ten-year period.

Additionally, reductions associated from the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies.

At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The commission has conducted air quality modeling and upper air monitoring that found regional air pollution should be considered when studying air quality in Texas' ozone nonattainment areas. This work is supported by research conducted by OTAG, the most comprehensive attempt ever undertaken to understand and quanitfy the transport of ozone. Both the commission and the OTAG study point to the need to take a regional approach to controlling air pollutants.

BCCA, ExxonMobil, Phillips 66, REI, and TPIEC commented on the draft RIA and stated that the proposed rules were not evaluated in accordance with the analysis requirements for a major environmental rule. The commenters stated that Texas Government Code, §2001.0225, requires an RIA for certain major environmental rules. The commenters stated that the commission must consider the benefits and costs of the proposed rule in relationship to state agencies, local governments, the public, the regulated community, and the environment. The commenters stated further that the commission must also incorporate aspects of this analysis into the fiscal note in the proposed rules (e.g., identify the costs and the benefits; describe reasonable alternative methods for achieving the purpose of the rule considered by the agency; provide the reasons for rejecting those alternatives; and identify the data and methodology used in performing the analysis). The commenters stated that under §2001.0225(d) the commission must also find that "compared to the alternative proposals considered and rejected, the rule will result in the best combination of effectiveness in obtaining the desired results and of economic costs not materially greater than the costs of any alternative regulatory method considered."

The commenters stated that the rule proposal preamble's statement that the rules are exempt from the RIA requirement because federal law mandates the rules is a legally flawed effort to avoid an RIA and may render the rules invalid. The commenters stated that federal law does not mandate the control requirements, emission rates, and use restrictions contained in the proposal and asserted that many of the proposed rules exceed specific federal rules and standards applicable to the same sources. The commenters stated that examples of departures from the federal framework include the following: boiler, turbine and other fired equipment emission limits set well below federal new source performance standards (NSPS), RACT, best available control technology (BACT), or lowest achievable emission rate (LAER) limits for the same sources; and compressor engine emission limits set at unprecedented low levels specifically designed to be unachievable and prevent the further use of the affected engines.

The commenters stated that the rule proposal preamble acknowledges that the rule proposal's components are "major environmental rules," but that the commission asserted that an RIA is "seldom" required and is only required for "extraordinary" rules. The commenters stated that these criteria appear nowhere in the RIA requirements. The commenters stated that the rule proposal preamble states that "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." The commenters stated that this "no greater than is necessary or appropriate" determination is the conclusion that an RIA is designed to evaluate and to offer for public review and comment. The commenters stated that the rule proposal is well beyond any federal mandates for the covered sources and are "extraordinary." The commenters stated that under Texas Government Code, §2001.0225, an RIA must be performed and offered for public comment before the proposal can be adopted.

ExxonMobil commented that simply saying that federal law requires the rules does not make it so. ExxonMobil stated that federal law, for instance, did not mandate a 90% reduction in emissions from stationary sources of NO_x, and that the commission alone decided the blend of control requirements in the proposal. ExxonMobil stated that if the commission was exempt from conducting a major environmental analysis solely because the proposal was intended to achieve compliance with the NAAQS, an analysis would never be required for any rule relating to criteria pollutants and such an approach would render Texas Government Code, §2001.0225, superfluous.

The commission does not agree that the adopted rules meet the definition of a major environmental rule, or that the commission's interpretation of the exemption for federally mandated standards is legally flawed. Further, the Draft RIA in the proposal preamble (25 TexReg 8259, August 25, 2000) did not state that the rules are major environmental rules. While the rules may require capital investments by batch processes, bakeries and offset lithographic printers, that alone is not enough to trigger the RIA requirements. The Texas Government Code, §2001.0225, only applies to a major environmental rule adopted by a state agency, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

This rulemaking action does not meet any of these four applicability requirements, and is adopted in substantial compliance with the RIA requirements. Texas Government Code, §2001.035. This rule does not exceed an express standard set by federal law because 42 USC, §7511a(b)(2)(C), requires states to ensure that RACT is in place for all major VOC sources in moderate and above ozone nonattainment areas. As discussed earlier in this preamble, the EPA has stated that the existing Chapter 115 vent gas rules do not represent RACT for batch processes in HGA, and consequently it is necessary to implement the Chapter 115 batch process rules in HGA. In addition, the EPA has identified a variety of deficiencies in the existing Chapter 115 bakery rule for HGA. Finally, there are an estimated 20 major source offset printers in HGA for which RACT rules have not been implemented. Correction of these deficiencies is necessary to ensure the implementation of RACT in HGA such that these rules are federally approvable.

Further, the adopted rules are also intended to obtain VOC emission reductions which will result in reductions in ozone formation in the HGA ozone nonattainment area under 42 USC, §7409. Title 42 USC, §7410, 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 42 USC, §7410, does not specifically prescribe programs, methods, or reductions to meet the federal 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 42 USC, Chapter 85, Air Pollution Prevention and Control). The FCAA does require some specific measures for SIP purposes, such as an inspection and maintenance program, but those programs are the exception, not the rule, in the federal SIP structure. 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. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Failure to develop control strategies to demonstrate attainment can result in federal sanctions. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commissions photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended, in part, to achieve reductions in ozone precursor emissions in the HGA nonattainment area. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA.

This conclusion is supported by the legislative history for Texas Government Code, 2001.0225. During the 75th Legislative Session, SB 633 amended the Texas Government Code to require agencies to perform a RIA of certain rules. The intent of SB 633 was to require agencies to conduct a RIA of 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. 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. Because of the ongoing need to address nonattainment demonstrations required by federal law, the commission routinely proposes and adopts SIP rules. If each rule proposed for inclusion in the SIP was incorrectly considered as exceeding federal law, every SIP rule would require the full RIA contemplated by SB 633. This result would be inconsistent with the cost estimates and fiscal notes prepared by the commission and by the LBB. 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 meet the requirements under §2001.0225(a). 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. In other words, the adopted rules are intended to meet federal and state law, and do not go above and beyond what is required to meet federal or state statutes.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied*); and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the APA by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, and 382.017, authorize the commission to implement a plan for the control of the states air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

Phillips 66 and TPIEC stated that the TCAA, §382.011(b), authorizes rules for controlling air contaminants by all practical and economically feasible methods. REI commented that the proposed emission limitations have been developed with less than a complete analysis of the technical or economic feasibility of the resulting controls or an analysis of the possible environmental or economic disbenefit of the proposed controls. TPEIC commented that under Texas Government Code, §2001.033(a)(1)(B), the rule must have a reasoned justification that includes a summary of the factual basis for the rule that demonstrates a rational connection between the factual basis for the rule and the rule as adopted. The commenters stated that under Texas Government Code, §2001.035(c), the justification must demonstrate in a relatively clear and logical fashion that the rule is a reasonable means to a legitimate objective. The commenters asserted that a rule that would impose an air emission abatement requirement that is not demonstrated to be practical and economically feasible is directly contrary to the TCAA and that promulgating such a rule without a reasoned justification is inconsistent with the Texas Government Code.

The commission disagrees with the commenters and has made no change in response to these comments. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of the proposed rules. This information met the statutory requirements of the TCAA and the APA because the information provided in the proposed rules was sufficient for commenters to submit alternative assessments of the costs and benefits.

Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn*, 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The preamble for the proposed rules contained a discussion of the FCAA requirements concerning RACT for these affected sources, a detailed section by section discussion of the proposed changes, a fiscal note, including the cost to state and local governments, the public benefit and the estimated costs for the affected sources, a small and micro-business analysis, a draft RIA, a TIA, and a CMP consistency determination. The commission received a number of comments that addressed multiple aspects of the adopted rules. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The commission believes that the preamble for the proposed rules provided adequate information that demonstrates that the adopted rules are economically and practically feasible. These rules do not require the installation of technology that is out of the ordinary; for example, some facilities might install thermocouples or catalytic oxidizers or use non-alcohol fountain solutions. The commission does not believe that these options or others similar to them are not economically and practically feasible. In fact, many facilities covered by the rules have already installed the controls necessary to comply. To simply state that the proposal did not meet the statute or that compliance with the proposed rules is not technically or economically feasible does not provide the commission with sufficient information to propose changes or alternative strategies. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the notice must include the cost of a reasonable method of compliance. Mere disagreement with cost or technical feasibility estimates does not render notice inadequate. The commenters did not say how the notice is insufficient, merely that it is insufficient. Nevertheless, the commission has reviewed the notice and has determined it is adequate. The commission did not receive specific comments on the technical or economic feasibility of the adopted rules.

The commission has provided a "reasoned justification" for the rules in this adoption package as required by Texas Government Code, §2001.033. The requirement for a reasoned justification applies to the agency order finally adopting a rule. The standard for compliance with the reasoned justification requirement is substantial compliance, as determined by the Legislature, which amended the reasoned justification requirement in 1999. The commission has provided the factual, policy and legal bases for the rule, as required. The Texas Government Code, §2001.024, requires only "a brief explanation" of the rule upon proposal in addition to other elements such as the fiscal note and public benefit evaluations. Both the rule proposal and adoption meet all of the requirements of the APA.

BCCA, ExxonMobil, Phillips 66, REI, and TPIEC stated that the proposed rules did not include adequate notice as required under Texas Government Code, §2002.024. The commenters stated that Texas Government Code, §2001.024, requires adequate notice of a proposed rule, including information about its public benefits and costs. The commenters stated that adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule, and that courts have considered notice "adequate" only if: interested persons can confront the agency's factual suppositions and policy preconceptions; and the agency provides interested parties the opportunity to challenge the underlying factual data relied upon by the agency. The commenters asserted that in proposing the rules, the commission failed to provide interested parties with sufficient information to constitute adequate notice.

The commenters stated that the rule proposal preamble appears short of adequate notice because the cost estimates were "dramatically underestimated." The commenters stated that the commission published insufficient information and analysis regarding costs and impacts.

The commenters stated that the commission published insufficient information and analysis regarding costs and impacts. The commenters stated that the commission "has not been completely responsive to stakeholder requests for information necessary to comment effectively" and "dramatically underestimated" the costs of the proposed control strategies, and that as a result, the notice of the proposal is inadequate.

The commenters stated that it has identified a number of critical gaps in the underlying factual data, methodology, and analysis in support of the proposed rules. The commenters asserted that the proposal included insufficient information and analysis regarding costs and impacts. The commenters asserted that the commission has not adequately responded to requests for additional information from stakeholders. The commenters stated that the following requests for information were outstanding: information regarding the modeling of emissions; information regarding the corrected EI database; and information supporting the estimated costs of control. The commenters stated that this information is necessary in order to comment effectively on the proposed rules and that data gaps in the proposal hindered effective comment.

The commission disagrees with the commenters and has made no change in response to these comments. Texas Government Code, §2001.024, requires of the notice of a proposed rule include certain information. Subsection (a)(5) requires that the notice state the public benefits expected as a result of the adoption of the proposed rule and the probable economic cost to persons required to comply with the rule. Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn*, 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of the proposed rules. The preamble for the proposed rules contained a discussion of the FCAA requirements concerning RACT for these affected sources, a detailed section by section discussion of the proposed changes, a fiscal note, including the cost to state and local governments, the public benefit and the estimated costs for the affected sources, a small and micro-business analysis, a draft RIA, a TIA, and a CMP consistency determination. The commission received a number of comments that addressed multiple aspects of the adopted rules. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the notice must include the cost of a reasonable method of compliance. The commenters' statements that the costs were "dramatically underestimated" did not state how that conclusion was reached. Mere disagreement with cost estimates does not render notice inadequate.

The proposed rules met the requirement to include sufficient information in explaining the requirements for batch processes, offset lithographers, and bakeries, the compliance schedule, the anticipated cost of compliance and the anticipated reduction in emissions. To simply state that the proposal failed to provide sufficient information does not provide the commission with sufficient information to propose changes or alternative strategies. The commenters did not say how the notice is insufficient, merely that it is insufficient. Nevertheless, the commission has reviewed the notice and has determined it is adequate. Similarly, the comments which state there are critical gaps did not identify what those gaps are or how that results in inadequate notice. The commission is unaware of any requests for additional information to which it was not completely responsive.

BCCA, ExxonMobil, Phillips 66, REI, and TPIEC stated that the proposed rules did not include the local employment impact statement required under Texas Government Code, §2001.022. The commenters stated that Texas Government Code, §2001.022, requires the commission to determine whether the rule proposal has the potential to affect a local economy before proposing the rule for adoption. The commenters believed that if answered affirmatively, the commission must request that the Texas Employment Commission to prepare a local employment impact statement describing in detail the probable effect of the rule on employment in each geographic area affected by the rule for each year of the first five years that the rule will be in effect. The commenters further asserted that the commission failed to make the required initial determination and ignored the potential for the proposal to adversely affect the local economy. The commenters stated that a local employment impact statement should have been requested and prepared in advance of the proposal.

The commission agrees with the commenters that the adopted rules may affect a local economy; however, it does not agree that it is the responsibility of the commission to provide the local employment impact analysis. The APA requires state agencies to determine whether a rule may affect a local economy before proposing a rule for adoption. If the agency determines that a proposed rule may affect a local economy, the agency must send a copy of the proposed rule and other information to the Texas Workforce Commission (Workforce Commission) before the agency files notice of the proposed rule with the secretary of state. The APA requires the Workforce Commission to prepare a local employment impact statement for proposed rules, if a state agency requests the statement. The commission determined that the proposed rules might affect a local economy, and sent the proposed rules and other requested information to the Workforce Commission. The commission received a letter from the Workforce Commission, indicating that the Workforce Commission did not have the ability to determine the potential local employment impacts from the proposed rules.

BCCA, ExxonMobil, Phillips 66, REI, and TPIEC stated that the proposed rules did not include an adequate TIA as required under Texas Government Code, §2007. The commenters stated that the TIA provision mandates that covered agencies "take a 'hard look' at the private real property implications of the actions they undertake...," according to the Office of the Attorney General, *Private Real Property Rights Preservation Act Guidelines*, (21 TexReg 387, January 12, 1996). The commenters stated that under §2007.043, a TIA must describe the specific purpose of the proposed action, determine whether engaging in the proposed governmental action will constitute a taking, and describe reasonable alternative actions that could accomplish the specified purpose. The commenters stated that the agency must also explain whether these alternative actions also would constitute takings.

The commenters stated that agencies must also comply with guidelines developed by the Texas Attorney General when developing the TIA and that according to these guidelines, agencies must carefully review governmental actions that have a significant impact on the owner's economic interest. The commenters stated that these guidelines include the statement: "Although a reduction in property value alone may not be a 'taking,' a severe reduction in property value often indicates a reduction or elimination of reasonably profitable uses." (21 TexReg 392, January 12, 1996).

The commenters stated that the proposed rule preamble acknowledged that some of the rules may "burden" private real property but claimed an exemption from performing a TIA based on the assertion that the proposal does not impose a greater burden than necessary to advance a health and safety purpose and that the proposal "reasonably" fulfills a federal mandate. The commenters stated that the commission provided the public no basis to infer that a cost/benefit analysis or a reasonableness determination was, in fact, performed as necessary to support the TIA exemption claim because the preamble contains only the bare assertions. The commenters asserted that the proposed rules will impose a greater burden than is necessary, and are not reasonably taken to fulfill a federal mandate. The commenters believed that according to the Attorney General's Guidelines, a full TIA was required to be completed with the proposal, and that failure to perform a TIA could invalidate the rules.

As stated previously in the preamble, the purpose of the adopted rules is to ensure that RACT is in place for all major VOC sources in the HGA ozone nonattainment area in order to conform with the EPA's RACT requirements, thus enabling the Chapter 115 batch process, offset lithographic printing, and bakery rules for HGA to be federally approvable; and to obtain VOC emission reductions which will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The commission noted in the proposal that the rules may require the installation of control systems at batch process operations, offset lithographic printers, and bakeries in HGA in some cases. The acknowledgment that the rules may require a capital expenditure or the installation of controls, is simply that, an acknowledgment. The commission understands that the rules may have an impact on real property and in noting this, sought comments on any potential impact to ensure that the adopted rules are technically and economically feasible. The commission believes that this acknowledgment has caused the commenters to misunderstand the commission's interpretation of the requirements of Texas Government Code, Chapter 2007. The commission does not believe that the assessment required by Chapter 2007 begins with a determination of whether or not the proposed rules could result in a capital expenditure. Rather, the commission believes that before an assessment is required, the commission must determine whether Chapter 2007 applies to the government action. If the proposed action is subject to an exception to Chapter 2007, the analysis is complete. Section 2007.003(b) provides that "this chapter does not apply to the following governmental actions:...." Because the commission believes the adopted rules meet the two exceptions to Chapter 2007, the full TIA is not required for the rules. Both of these exceptions were noted in the proposal preamble.

The commission believes the adopted rules are exempt under Texas Government Code, §2007.003(b)(4) because they are reasonably taken to fulfill an obligation mandated by federal law. While several governmental actions are subject to being reviewed under Chapter 2007, including the adoption of rules, §2007.003(b)(4) specifically excludes an action that is reasonably taken to fulfill an obligation mandated by federal law. One purpose of this rulemaking is to ensure that RACT is in place for all major VOC sources in the HGA ozone nonattainment area as required under federal law. The adoption of these rules ensure that these VOC sources can operate in compliance with federal law. Further, the rules are adopted to meet the air quality standards established under federal law as NAAQS.

The commission also believes that the adopted rules meet an additional exception to the requirements of Texas Government Code, Chapter 2007. First, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rule revisions 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 significantly advance the health and safety purpose. This action is taken in response to the HGA area exceeding the federal ambient air quality standard for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ambient VOC and ozone levels in HGA. Consequently, these rules meet the exemption in §2007.003(b)(13).

The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking therefore meets the requirements of Texas Government Code, §2007.003(b)(4) and (13). For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

BCCA, ExxonMobil, Phillips 66, REI, and TPIEC stated that the proposed rules did not include an adequate small business and micro-business assessment as required under Texas Government Code, 2006.002. The commenters stated that a an analysis of the costs of compliance for small and micro-businesses must also compare the costs of compliance for these businesses with the costs for the largest businesses affected by the rule. The commenters stated that the comparison must use at least one of the following standards: cost for each employee, cost for each hour of labor, or cost for each $100 of sales. The commenters asserted that the rule proposal failed to include the mandated cost comparison standards. The commenters stated that this is the case even in those instances where the commission acknowledged a significant impact. The commenters stated that the commission either restated the costs of compliance it identified in the analysis of public benefits and costs, or concluded that it cannot determine the cost to small businesses. The commenters stated that the rule proposal preamble stated that "the estimated capital and annualized cost of installing and operating control technology used for the various types of equipment in fiscal note would appear to be a reasonable cost estimate for small and micro-businesses." (25 TexReg 8293).

The commenters asserted that the rule proposal's assessments fall short of what Texas law requires and that it is not sufficient for the agency merely to state that the costs for small and large businesses will be the same. The commenters stated that the rationale behind requiring a comparison using an established standard (e.g., cost for each employee, cost for each hour of labor, or cost for each $100 of sales) is to determine whether there is a disparate impact on small businesses. The commenters stated that according to *Unified Loans v. Pettijohn*, 955 S.W.2d at 652 (Court of Appeals -- Austin, 1997), the statute's purpose is to obtain "an objective assessment of the agency's proposed action by forcing it to consider seriously. . . the effect of the rule on small businesses, including an analysis of their costs of {compliance} and a comparison of their costs with the cost of compliance for the largest businesses affected. ..." The commenters stated further that the commission cannot merely conclude that the costs to small businesses "cannot be determined," and is obliged to include in the notice "some basis" for its conclusion so that interested parties can "confront that basis in a meaningful way in their comments." (*Unified Loans v. Pettijohn*, 955 S.W.2d at 653.)

The commenters stated that in the rule proposal preamble, the commission did not publish the information mandated by Texas law and that as a result, it is impossible for the public to comment on whether the agency adequately considered the effect of the rule on small businesses, thus rendering the notice of the plan inadequate. The commenters stated that Texas Government Code, §2006.002, requires the commission to provide a comparison of the proposed rule's impact on small and large businesses, using the specified standards, for public review and comment before adoption.

The commission stated in the small business and micro-business assessment in proposal preamble that it was unable to identify any such businesses that would be affected by the proposed amendments. (See the August 25, 2000 issue of the *Texas Register* (25 TexReg 8259).) Since the commission was unable to identify any small or micro-businesses, it was not possible to provide an analysis based on the number of employees, hours of labor, or amount of sales income. Nevertheless, in order to provide a basis for comments on the potential impacts for small or micro-businesses, the commission estimated, to the extent possible, the costs based on the estimated annualized cost for installing and operating control technology in dollars per ton of VOC reduced that was used for various types of units in the fiscal note in the proposal preamble. Since the commission did not have access to the information contemplated by the statute, the use of an annualized cost was a meaningful way to provide sufficient notice of the cost to small and micro-businesses and therefore meets the objective of the Texas Government Code, Chapter 2006. Although the commission received several comments on the rules, none of the commenters identified themselves as small or micro-businesses.

Sierra-Houston resubmitted comment letters dated August 2, 1999, January 31, 2000, and February 24, 2000 concerning already-completed rulemakings and SIP revisions which Sierra-Houston had initially submitted during the comment period for these previous rulemakings and SIP revisions.

These comments were addressed in the ANALYSIS OF TESTIMONY section of the preambles to the earlier rulemakings and SIP revisions which were published in previous issues of the *Texas Register*.

Two individuals questioned whether bakeries produce a significant amount of controllable VOCs. One of the individuals also questioned whether offset lithographic printers produce a significant amount of controllable VOCs.

The adopted rules concerning VOC emissions from bakeries and offset printers in HGA apply only to major sources, which by definition are considered to be significant emission sources.

Montgomery Co. commented that the estimated emission reductions from VOC RACT rules for bakeries, batch processes, and offset lithographic printers were unknown.

No emission reductions are associated with the revisions to the existing Chapter 115 bakery rule since the emission reduction credit was taken in a previous SIP revision. As noted earlier in this preamble, deficiencies in the bakery rule as it applies in HGA must be corrected for the HGA Attainment Demonstration SIP to be approvable. Specifically, the EPA has specified that RACT for bakery ovens is 80 - 90% control efficiency, while the commission rule as negotiated in 1994 requires only a 30% emission reduction. Consequently, adoption and implementation of an approvable Chapter 115 rule for bakeries in HGA is necessary, regardless of the magnitude of the associated emission reductions.

As noted earlier in this preamble, staff attempted to develop a demonstration of equivalency between the existing general vent gas rule and the batch processes ACT using the EPA's 5% rule. The EPA's "5% rule" provides a mechanism for states to justify exemptions or cutpoints which are more lenient than the EPA's RACT baseline. It is applied by determining the total emissions allowed by the EPA's RACT baseline (including exemptions) and comparing this to the emissions allowed (including exemptions) by a state regulation. If the difference is less than 5.0%, the EPA considers that there is no substantive difference between the EPA and state requirements. The staff was unable to assemble the information necessary to demonstrate to the EPA's satisfaction that existing rules represent RACT for batch processes in HGA because some of the necessary information is known only by the affected industry sources. Therefore, it is not possible at this time for the commission to estimate the emission reductions associated with the batch process rule. However, adoption and implementation of a Chapter 115 rule for batch processes in HGA is necessary, regardless of the magnitude of the associated emission reductions.

As noted earlier in this preamble, the Chapter 115 offset lithographic printing rule (§§115.440, 115.442, 115.443, 115.445, 115.446, and 115.449) is currently a contingency rule for HGA. Because HGA is a severe ozone nonattainment area, a source in HGA is major if it has the potential to emit 25 tpy or more of VOC emissions. FCAA, 42 USC, §7511a(b)(2), requires that RACT be applied to major sources, and consequently it is necessary to implement this rule in HGA for sources with VOC emissions equal to or greater than 25 tpy. A previous retrieval from the EI did not reveal any major source offset printers in HGA. However, it has come to the commission's attention that there are approximately 20 offset printers in HGA that are major sources. Therefore, adoption and implementation of a Chapter 115 rule for offset printers in HGA is necessary, regardless of the magnitude of the associated emission reductions.

An individual suggested that the commission develop a rule to require inspection and monitoring of cooling towers, which the individual stated can emit significant quantities of VOC.

The commission agrees that cooling towers can emit significant quantities of VOC, and has begun preliminary research concerning such a possible rule.

Four individuals expressed concern about enforcement of the proposed rules, and one of these individuals recommended high penalties for noncompliance. One individual commented that the enforcement of the rules in Liberty County would be difficult because they would be hard pressed to justify allocating resources and manpower to enforce these types of rules when there are more serious problems in that area.

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. The commission will work with local officials to ensure enforcement of the SIP and SIP rules. The commission has existing relationships with pollution control authorities in the City of Houston, Harris County, and Galveston County for enforcement of other commission rules. The commission will continue enforcement relationships with these entities and develop relationships with other local officials as needed to create effective enforcement mechanisms for the SIP and SIP rules.

Missouri City questioned whether it would be required to enforce the proposed Chapter 115 revisions.

The rules are enforced by staff in the TNRCC's regional offices, as well as local air pollution control programs. Local governments have the same power and are subject to the same restrictions as the commission under TCAA, §382.015, Power to Enter Property, to inspect the air and to enter public or private property in its territorial jurisdiction to determine if the level of air contaminants in an area in its territorial jurisdiction meet levels set by the commission. Local governments are not required to enforce commission rules but may sign cooperative agreements with the commission to enforce the rules under TCAA, §382.115, Cooperative Agreements. Local programs can also enforce commission rules without signing a cooperative agreement. The authority of local governments to enforce air pollution requirements is specified in detail in TCAA, §§382.111 - 382.115, and local governments can institute civil actions in the same manner as the commission pursuant to Texas Water Code, §7.351.

No comments were received on §115.10, concerning Definitions. However, it has come to the commission's attention that a definition of "incinerator" is needed in §115.10 because the definition of this term in §101.1 specifically refers to devices used to combust solid or liquid materials. Because the term "incinerator," when used throughout Chapter 115, refers to control devices used to combust VOC vapors, the commission has added a definition of incinerator to §115.10 to clarify the distinction. The new definition is not a substantive change from how this term has always been used in Chapter 115, and its inclusion in the adopted rule will provide clarity. Subsequent definitions in §115.10 were renumbered due to the addition of the definition of incinerator.

Sierra-Houston stated that the vent gas rules of §§115.122 - 115.129; the batch process rules of §§115.161 - 115.169; the VOC transfer rules of §§115.211 - 115.216; the Stage II vapor recovery definitions of §115.240; the rotogravure and flexographic printing definitions of §115.430; and the offset printing rules of §115.449 should apply statewide so maximum reduction of precursors and their transboundary air pollution will occur. An individual stated that all requirements should apply statewide.

The commission appreciates the commenters' support for statewide applicability of the adopted rules. The commission notes, however, that it is not obligated to adopt all rules statewide in order to satisfy its commitments under the SIP, nor is the commission required to do so under the FCAA. Three of the adopted measures contain emission reduction strategies that have been adopted with state- wide applicability: California Large-Spark Ignition Engines; Emissions Banking and Trading Program (that portion of the adopted rule which relates to the trading of emission reduction credits and discrete emission reduction credits); and Cleaner Diesel Fuel (that portion of the adopted rule which relates to on-highway fuel).

In evaluating whether to implement all of the rules statewide, the commission took into account many concerns, including but not limited to, the need for the marketplace to be able to respond to regulation, the possible impacts on transport and distribution systems, the possibility of increased costs and financial burdens on regulated entities, and regional needs and issues associated with state-wide mandates. The commission analyzed where emission reduction measures are most needed and where emission reduction measures will be most effective in order to demonstrate attainment.

TPIEC stated that the vent gas rule was never intended to apply to pulp and paper sources, that the origins of the vent gas rule are not entirely clear, and that the vent gas rule should not apply to the pulp and paper industry. TPIEC stated that the requirement to control sources greater than 612 ppmv appears to have been based, in part, on EPA's CTG for surface coating of cans, coils, paper, fabrics, automobiles, and light duty trucks, while other parts of the rule may have been based on the CTG for synthetic organic chemical manufacturing industry (SOCMI) sources. TPIEC stated that the feasibility of this rule as applied to the pulp and paper industry was never considered by the commission when promulgating the rule, and that the commission has never counted any reduction from the application of the rule to the pulp and paper industry in any SIP demonstration. TPIEC stated that since pulp and paper manufacturing is essentially a water-based operation which includes a large inorganic load in process and waste streams, the emissions of concentrated VOC are negligible.

The general vent gas rule was initially adopted in 1972 to control VOC emissions from various industrial process vents which, at the time, were generally uncontrolled. The rule originally contained an exemption limit of 30,000 ppmv, or 3.0% by volume, for all sources, because most vent gas streams containing this concentration level of VOCs will burn without the use of supplemental fuel. Consequently, the installation of a flare or thermal oxidizer was a highly cost-effective first step in controlling vent gas stream emissions.

In July 1985, the Texas Air Control Board (TACB, predecessor to the commission) lowered the exemption limit to 612 ppmv for all vent gas sources in Dallas and Tarrant Counties, with a compliance date of December 31, 1987. In May 1992, the TACB lowered the exemption limit to 612 ppmv for all vent gas sources in the other 14 ozone nonattainment counties, with a compliance date of July 31, 1994. The 612 ppmv limit was based on an EPA CTG limit for the control of VOCs in SOCMI vent gas sources. In November 1993, in response to an industry request, the commission extended the compliance date to May 31, 1995 for all sources. In May 1994, in response to a petition for rulemaking from TPIEC, the commission extended the compliance date for pulp and paper mills until November 15, 1998. At the time the extension was approved, the EPA was in the process of developing a multi-media pulp and paper Maximum Achievable Control Technology (MACT) standard with targeted promulgation and compliance dates of 1995 and 1998, respectively. Industry representatives were concerned that the installation of control technology for compliance with the vent gas rule might soon be incompatible with control requirements specified by the forthcoming MACT standard. The commission agreed that controls installed for compliance with the vent gas rule might not be cost-effective if they had to be reworked in the near term. In April 1997, the commission again extended the exemption until November 15, 1999 because of the EPA delay in issuing the MACT. The MACT (40 CFR 63, Subpart S) was promulgated on December 28, 1998, and some control technology conflicts do exist. Both the vent gas rule and the MACT target some of the same processes for control, but with differing compliance deadlines. The industry then asked that the commission once again extend the vent gas rule's November 15, 1999 compliance date to avoid the need to control processes that will be shut down or otherwise controlled by the extension date. In October 1999, the commission again extended the compliance date until April 15, 2001 but noted that while it believed that the extension until April 15, 2001 was reasonable, the commission could not foresee a circumstance where an additional extension would be necessary or granted. Therefore, the commission believes that the vent gas rule should apply to the pulp and paper industry. The affected mills need to be in compliance with the rule by April 15, 2001 to forestall any enforcement action.

The EPA commented on the "once-in, always-in" (OIAI) requirement of §115.122(a)(4). The EPA stated that Chapter 106 has not been submitted as part of the SIP. The EPA commented that as a result, any vent gas stream for which a company elected to use the OIAI exemption (available under §115.122(a)(4)(A)) would still be subject to the vent gas rule from the federal enforcement perspective unless commission submitted the individual permit-by-rule as part of the SIP.

OIAI is an EPA concept which means that once emissions from a source exceed the applicability cutoff for a particular VOC regulation in the SIP, that source is always subject to the control requirements of the regulation. The purpose of this requirement is two-fold. First, it serves to discourage a source already subject to regulation from installing minimal controls to circumvent RACT requirements. Second, it improves the clarity of VOC regulations by minimizing the confusion over whether variations in production cause a particular source to be covered by a regulation. A major EPA concern which resulted in the OIAI requirements was their desire to prevent the removal of a control device, which would then result in a significant increase in emissions (i.e., a throughput reduction of 5.0% could result in an emissions increase of 90% if the control device were removed). To provide flexibility but prevent such emissions increases, the existing rule language includes an incentive for cost-effective and innovative approaches to pollution prevention and waste minimization which reduce emissions to no more than the controlled levels prior to removal of control devices. Also, it should be noted that in the event of revised rules which are less stringent than previous requirements (for example, revisions to the definition of VOC which exclude additional compounds from classification as VOC), the OIAI requirements will apply to the extent that emissions from a source exceed the applicability cutoff for the revised version of the rules. In the current rulemaking, the commission is simply revising §115.122(a)(4) to refer to "permit by rule" rather than "standard exemption" due to the requirements of SB 766, which amended the TCAA and created "permits by rule." Prior to passage of SB 766, the commission had the authority under TCAA, §382.057, to exempt from permitting requirements, changes within any facility and certain types of facilities that would not make a significant contribution of air contaminants to the atmosphere. In order to remove the appearance that these insignificant facilities were exempt from environmental regulation in addition to being exempt from permitting, the new TCAA, §382.05196 gives the commission the authority to adopt permits by rule for certain types of facilities that will not make a significant contribution of air contaminants to the atmosphere. On August 9, 2000, the commission adopted revisions to 30 TAC Chapter 106 in order to use permits by rule to authorize new construction and/or modifications or changes (25 TexReg 8653 (September 1, 2000)). On August 13, 1982, (47 Federal Register 35183), the EPA published its approval of several revisions to 30 TAC Chapter 116 that were submitted to the EPA for SIP approval on May 9, 1975. Part of that May 9, 1975 submittal included §116.6, Exemptions. Although §116.6 has since been revised, the version that existed at the time of the August 13, 1982 SIP approval has not been withdrawn from the SIP. Thus, the basic regulatory authority for exemptions, now permits by rule, is in the SIP. In a letter dated June 4, 1990 from Merrit Nicewander, Chief, New Source Review Section, EPA Region VI, to Lawrence Pewitt, Director of the TACB Permits Division, the EPA stated that where the TACB issues standard exemptions pursuant to state regulations that were developed in accordance with the Texas SIP, the standard exemptions themselves are federally enforceable. Thus, since permits by rule are federally enforceable, companies may rely upon them in order to meet the exemption allowed by §115.122(a)(4). The commission has updated the references in §115.122(a)(1)(A), (b)(1), and (c)(1)(A) and (2) from "Centigrade" to "Celsius" since this is now the term commonly used to describe this temperature scale. In addition, the commission revised §115.122(a)(3)(E) by changing a reference from "§101.29 of this title (relating to Emissions Credit Banking and Trading)" to "Chapter 101, Subchapter H, Division 1 of this title (relating to Emission Credit Banking and Trading)" due to the repeal of §101.29 and its relocation to a new division within Chapter 101 in concurrent rulemaking published elsewhere in this issue of the *Texas Register*.

TCC stated that the commission did not provide a basis for extending the existing test methods and recordkeeping requirements in §115.126 to the attainment counties of Aransas, Bexar, Calhoun, Matagorda, San Patricio, and Travis; while Union Carbide commented that extending the test methods to Calhoun and the other named counties is not appropriate at this time. TCC and Union Carbide stated that monitoring and recordkeeping activities do not, in and of themselves, reduce emissions and suggested that these requirements be deleted for those counties. Union Carbide also stated that Title V permits might have to be updated and stated that compliance with the standards and exemptions could be accomplished as part of the Title V permitting process. Union Carbide requested that Calhoun and the other named counties not be included in the requirements of §115.125

and §115.126 and that the proposed changes only be reconsidered if there is a benefit to air quality in those areas or the ozone near-nonattainment areas.

In general, the purpose of §115.125 is simply to list the approved test methods to be used when testing is specifically required within this division (Vent Gas Control), when the executive director requests testing under §101.8 (Sampling), or when the owner or operator chooses to conduct testing of one or more vent gas streams. The changes to §115.125 do not add any requirements to Aransas, Bexar, Calhoun, Matagorda, Nueces, San Patricio, and Travis Counties, nor do the revisions to §115.126 add any requirements for the installation of monitors in these counties. However, the revisions to §115.126 add recordkeeping requirements for exempt vent gas streams in Aransas, Bexar, Calhoun, Matagorda, San Patricio, and Travis Counties.

It should be noted that §115.126 historically has not included specific recordkeeping requirements for vent gas sources in these six counties. The commission believes that it is necessary for inspection and enforcement purposes to add recordkeeping requirements in these counties which are sufficient to document compliance with the exemptions. It is true that because Chapter 115 is an applicable requirement under 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 115 requirements for each emission unit affected by the revisions to Chapter 115 at their site. However, inclusion of appropriate requirements in Chapter 115 could facilitate the issuance of operating permits by minimizing the "gaps" in the vent gas rule that must be addressed in these permits prior to their issuance.

The commission has revised §115.125(3)(C) and (D) to clarify that these subparagraphs specify requirements for flares in BPA, DFW, and HGA and for vapor combustors in Victoria County, BPA, DFW, ELP, and HGA which the owner or operator elected to consider as flares, and that these requirements do not apply in other counties.

TCC stated that some flares operate under a waiver from testing according to 40 CFR 60.18 because of safety or toxics concerns, and suggested the addition of language to §115.125(3)(B) and (C) to address such situations.

The commission agrees and has made the suggested change.

TCC stated that flares and vapor combustors with existing test data that meet the requirements of §115.125(3) should not have to conduct additional testing.

The commission agrees that existing test data that meets the testing requirements is sufficient for purposes of compliance.

TPIEC commented that a June 30, 2000 Rule Interpretation Memo (No. R5-112.008/R5- 121.010) concluded that a determination of the applicability of the vent gas rule should be based on the primary function of a vessel at a given time, stating "if there is a fairly constant flow into and out of the vessel and the flow in roughly equals the flow out, the vessel should be considered a process vessel subject to the Vent Gas Control requirements...." TPIEC stated that this interpretation "will subject many pulp and paper vessels to the vent gas rule, even though the same materials when in storage are exempt from the VOC storage tank requirements and the only change is that they have now been diluted with water in a process tank."

This rule interpretation memo also states, "Please note, in the event that an external customer feels that this rule interpretation is in error or a source of information has been overlooked which would change the determination, a request for reconsideration may be submitted. Requests must be submitted on a Reconsideration Process Form which is available at the TNRCC's homepage: http://www.tnrcc.state.tx.us/air/opd/rimhmpg.htm or from any of the air rule interpretation team members." Consequently, if TPIEC believes this memo to be in error, it may submit a request for reconsideration of the decision.

Union Carbide commented on §115.126(1) and (2), and questioned if these requirements apply to sources in Calhoun County.

Section 115.126(1), concerning continuous monitoring and recording of control device operating parameters, specifically applies to Victoria County and the 16 counties of the BPA, DFW, ELP, and HGA ozone nonattainment areas. It does not apply to Aransas, Bexar, Calhoun, Matagorda, Nueces, San Patricio, and Travis Counties. Section 115.126(2) applies to the 16 counties of the BPA, DFW, ELP, and HGA ozone nonattainment areas as well as Aransas, Bexar, Calhoun, Matagorda, Nueces, San Patricio, Travis, and Victoria Counties. However, §115.126(2) simply requires the owner or operator to maintain a record of the results of any testing conducted. The commission has made no change in response to the comment.

The commission notes that any reactor process or distillation operation vent gas stream with a flow rate less than 0.011 standard cubic meters per minute is exempt from the requirements of §115.121(a)(2)(A) under §115.127(a)(4)(C). It has come to the commission's attention that such vent gas streams which qualify for the flow rate exemption should only need records of the maximum design flow rate of the vent gas stream, rather than the records specified under §115.126(3)(A) - (C). Therefore, the commission has added a new §115.126(3)(D) which requires records of the maximum design flow rate of each vent gas stream claimed exempt under §115.127(a)(4)(C). The commission also notes that any reactor process or distillation operation operating in a process unit with a total design capacity of less than 1,100 tpy, for all chemicals produced within that unit, is exempt from the requirements of §115.121(a)(2)(A) under §115.127(a)(4)(B). It has come to the commission's attention that such exempt process units should only need records of the total design capacity of the unit, rather than the records specified under §115.126(3)(A) - (C). Therefore, the commission has added a new §115.126(3)(E) which requires records of the total design capacity of process units exempt under §115.127(a)(4)(B). The new §115.126(3)(D) and (E) will relieve the owners or operators of these exempt vent gas streams and exempt process units from keeping unnecessary records.

TPIEC and Union Carbide commented on §115.126(3) and (4), concerning records for exempted vents. TPIEC and Union Carbide stated that it is not clear if engineering calculations can be used instead of testing in §115.126(3). TPIEC and Union Carbide recommended that §115.126(3) should be revised to make it clear that engineering calculations can be used instead of testing (i.e., similar to §115.126(4)). Union Carbide stated that the rule should be clear with respect to which sources must be tested to show that they meet the exemptions of §115.127. TPIEC expressed concern about the number of pulp and paper industry vents between 306 and 612 ppmv for which owners or operators would have to demonstrate daily compliance with the 612 ppmv exemption, and stated that the daily requirements of the vent gas rule are more burdensome than other Chapter 115 requirements.

The commission agrees that the recordkeeping requirements of §115.126(3) may be burdensome in some cases. To address the commenters' concerns, the commission revised §115.126(4) to allow the owner or operator to use engineering calculations to determine if a vent gas stream is below the applicable exemption limits at maximum operating conditions, regardless of whether the vent gas stream is below 50% of the exemption level.

TPIEC also suggested that the word "and" between §115.126(3)(B) and (C) should be "or" to make it clear that the owner or operator is not expected to keep all three records, regardless of applicability.

To qualify a vent gas stream for exemption, the owner or operator only needs to document that the conditions of one of the exemptions are met. The commission has revised §115.126(3) by changing "limits" to "limit" and adding "the following, as appropriate." In addition, the commission revised §115.126(4) by adding the parenthetical phrase "either VOC concentration or mass emission rate." Finally, the commission revised §115.126(4) by changing "paragraph (3)" to "paragraph (3)(B) and (C)" to make it clear that the recordkeeping requirements of §115.126(4) are an alternative to the recordkeeping requirements of §115.126(3)(B) and (C).

TPIEC suggested that §115.127(a)(2)(C) be revised to make the 30,000 ppmv exemption permanent for the pulp and paper industry. As an alternative, TPIEC suggested the addition of language to §115.126(3) stating that "Alternate methods of demonstrating compliance with exemption criteria in this division (relating to Vent Gas Control) may be approved by the executive director."

As noted earlier, when taking action in October 1999 to extend the compliance deadline to April 15, 2001, the commission noted that it believed that the extension until April 15, 2001 was reasonable but could not foresee a circumstance where an additional extension would be necessary or granted. There have been no developments since October 1999 that would change the commission's position. Therefore, the commission believes that the vent gas rule should apply to the pulp and paper industry and expects the affected mills to be in compliance with the rule by April 15, 2001. Regarding the commenter's suggested new rule language, it should be noted that §115.123 already specifies that alternate methods of demonstrating and documenting continuous compliance with the applicable control requirements or exemption criteria may be approved by the executive director in accordance with §115.910 of this title (relating to Availability of Alternate Means of Control) if emission reductions are demonstrated to be substantially equivalent. Therefore, the commission has made no change in response to the comment.

Union Carbide commented on §115.129 and suggested that an April 30, 2005 compliance date be specified for any new recordkeeping and testing requirements.

The commission agrees that a compliance date should be specified for the recordkeeping requirements of §115.126(3) and (4) which will apply to exempt vent gas streams in Aransas, Bexar, Calhoun, Matagorda, San Patricio, and Travis Counties and has added a new §115.129(g). However, the commission believes that a December 31, 2001 compliance date is sufficient for owners or operators to develop adequate documentation of the exemption status of their vent gas streams.

No changes were proposed to §115.162(3) and §115.212(a)(7). However, it has come to the commission's attention that the references to "standard exemption" need to be updated to "permit by rule" due to the requirements of SB 766, which amended the TCAA and created "permits by rule." The commission has updated §115.162(3) and §115.212(a)(7) accordingly. These changes do not impose additional requirements but merely reflect changes in terminology and in the title of Chapter 106.

GEHC suggested that the Stage II vapor recovery rules of §§115.240 - 115.249 should apply to all gas stations. Another individual generally supported use of vapor recovery systems at gas stations.

The commission cannot revise these rules upon adoption to apply to additional gas stations in this rulemaking because the newly affected parties for which these rules do not currently apply would not have had adequate notice and opportunity to comment. Under the TCAA, Stage II vapor recovery systems are statutorily limited to use in ozone nonattainment areas. Consequently, the commission has made no change in response to the comment.

GEHC and an individual stated that most gas stations with which they are familiar do not have Stage II gas dispensing nozzles.

With very few exceptions, gas stations in ozone nonattainment counties have been required to have Stage II equipment for anywhere from two to eight years. The vast majority of these gas stations have installed vacuum-assist Stage II systems, which have nozzles that appear the same as non-Stage II nozzles at first glance. Therefore, it is likely that the gas stations that the commenters believe are not equipped with Stage II are, in fact, so equipped.

PIGC suggested a variety of changes to §§115.440, 115.442, and 115.446 which PIGC believes could provide additional flexibility to offset printing operations that are subject to the offset printing requirements of §§115.440, 115.442, 115.443, 115.445, 115.446, and 115.449.

Because only §115.449 was proposed for change, the commission is prohibited by the Administrative Procedures Act from revising any other sections in the Chapter 115 offset printing rules as part of the current rulemaking. However, some of the PIGC's suggestions, such as the "low VOC composite vapor pressure" option that PIGC would like added to §115.442(1)(F), could be handled case-by-case under the alternative control requirement option presently available under §115.443. The commission has made no change in response to the comment.

SUBCHAPTER A. DEFINITIONS

30 TAC §115.10

STATUTORY AUTHORITY

The amendment is 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.

§115.10. 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 ascribed to them 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 chapter, shall have the following meanings, unless the context clearly indicates otherwise. Additional definitions for terms used in this chapter are found in §101.1 of this title (relating to Definitions) and §3.2 of this title (relating to Definitions).

(1) Beaumont/Port Arthur area--Hardin, Jefferson, and Orange Counties.

(2) Capture efficiency--The amount of volatile organic compounds (VOC) collected by a capture system which is expressed as a percentage derived from the weight per unit time of VOC entering a capture system and delivered to a control device divided by the weight per unit time of total VOC generated by a source of VOC.

(3) Carbon adsorption system--A carbon adsorber with an inlet and outlet for exhaust gases and a system to regenerate the saturated adsorbent.

(4) Component--A piece of equipment, including, but not limited to pumps, valves, compressors, and pressure relief valves, which has the potential to leak VOC.

(5) Continuous monitoring--Any monitoring device used to comply with a continuous monitoring requirement of this chapter will be considered continuous if it can be demonstrated that at least 95% of the required data is captured.

(6) Covered attainment counties--Anderson, Angelina, Aransas, Atascosa, Austin, Bastrop, Bee, Bell, Bexar, Bosque, Bowie, Brazos, Burleson, Caldwell, Calhoun, Camp, Cass, Cherokee, Colorado, Comal, Cooke, Coryell, De Witt, Delta, Ellis, Falls, Fannin, Fayette, Franklin, Freestone, Goliad, Gonzales, Grayson, Gregg, Grimes, Guadalupe, Harrison, Hays, Henderson, Hill, Hood, Hopkins, Houston, Hunt, Jackson, Jasper, Johnson, Karnes, Kaufman, Lamar, Lavaca, Lee, Leon, Limestone, Live Oak, Madison, Marion, Matagorda, McLennan, Milam, Morris, Nacogdoches, Navarro, Newton, Nueces, Panola, Parker, Polk, Rains, Red River, Refugio, Robertson, Rockwall, Rusk, Sabine, San Jacinto, San Patricio, San Augustine, Shelby, Smith, Somervell, Titus, Travis, Trinity, Tyler, Upshur, Van Zandt, Victoria, Walker, Washington, Wharton, Williamson, Wilson, Wise, and Wood Counties.

(7) Dallas/Fort Worth area--Collin, Dallas, Denton, and Tarrant Counties.

(8) El Paso area--El Paso County.

(9) External floating roof--A cover or roof in an open-top tank which rests upon or is floated upon the liquid being contained and is equipped with a single or double seal to close the space between the roof edge and tank shell. A double seal consists of two complete and separate closure seals, one above the other, containing an enclosed space between them. For the purposes of this chapter (relating to Control of Air Pollution from Volatile Organic Compounds), an external floating roof storage tank which is equipped with a self-supporting fixed roof (typically a bolted aluminum geodesic dome) shall be considered to be an internal floating roof storage tank.

(10) Fugitive emission--Any VOC entering the atmosphere which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening designed to direct or control its flow.

(11) Gasoline bulk plant--A gasoline loading and/or unloading facility, excluding marine terminals, having a gasoline throughput less than 20,000 gallons (75,708 liters) per day, averaged over each consecutive 30-day period. A motor vehicle fuel dispensing facility is not a gasoline bulk plant.

(12) Gasoline terminal--A gasoline loading and/or unloading facility, excluding marine terminals, having a gasoline throughput equal to or greater than 20,000 gallons (75,708 liters) per day, averaged over each consecutive 30-day period.

(13) Houston/Galveston area--Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties.

(14) Incinerator--For the purposes of this chapter (relating to Control of Air Pollution from Volatile Organic Compounds), an enclosed control device that combusts or oxidizes VOC gases or vapors.

(15) Internal floating cover--A cover or floating roof in a fixed roof tank which rests upon or is floated upon the liquid being contained, and is equipped with a closure seal or seals to close the space between the cover edge and tank shell. For the purposes of this chapter (relating to Control of Air Pollution from Volatile Organic Compounds), an external floating roof storage tank which is equipped with a self-supporting fixed roof (typically a bolted aluminum geodesic dome) shall be considered to be an internal floating roof storage tank.

(16) Liquefied petroleum gas--Any material that is composed predominantly of any of the following hydrocarbons or mixtures of hydrocarbons: propane, propylene, normal butane, isobutane, and butylenes.

(17) Leak-free marine vessel--A marine vessel whose cargo tank closures (hatch covers, expansion domes, ullage openings, butterworth covers, and gauging covers) were inspected prior to cargo transfer operations and all such closures were properly secured such that no leaks of liquid or vapors can be detected by sight, sound, or smell. Cargo tank closures shall meet the applicable rules or regulations of the marine vessel's classification society or flag state. Cargo tank pressure/vacuum valves shall be operating within the range specified by the marine vessel's classification society or flag state and seated when tank pressure is less than 80% of set point pressure such that no vapor leaks can be detected by sight, sound, or smell. As an alternative, a marine vessel operated at negative pressure is assumed to be leak-free for the purpose of this standard.

(18) Marine loading facility--The loading arm(s), pumps, meters, shutoff valves, relief valves, and other piping and valves that are part of a single system used to fill a marine vessel at a single geographic site. Loading equipment that is physically separate (i.e., does not share common piping, valves, and other loading equipment) is considered to be a separate marine loading facility.

(19) Marine loading operation--The transfer of oil, gasoline, or other volatile organic liquids at any affected marine terminal, beginning with the connections made to a marine vessel and ending with the disconnection from the marine vessel.

(20) Marine terminal--Any marine facility or structure constructed to load oil, gasoline, or other volatile organic liquid bulk cargo into a marine vessel. A marine terminal consists of one or more marine loading facilities.

(21) Natural gas/gasoline processing--A process that extracts condensate from gases obtained from natural gas production and/or fractionates natural gas liquids into component products, such as ethane, propane, butane, and natural gasoline. The following facilities shall be included in this definition if, and only if, located on the same property as a natural gas/gasoline processing operation previously defined: compressor stations, dehydration units, sweetening units, field treatment, underground storage, liquified natural gas units, and field gas gathering systems.

(22) Petroleum refinery--Any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants,

or other products through distillation of crude oil, or through the redistillation, cracking, extraction, reforming, or other processing of unfinished petroleum derivatives.

(23) Polymer or resin manufacturing process--A process that produces any of the following polymers or resins: polyethylene, polypropylene, polystyrene, and styrenebutadiene latex.

(24) Printing line--An operation consisting of a series of one or more printing processes and including associated drying areas.

(25) Synthetic organic chemical manufacturing process--A process that produces, as intermediates or final products, one or more of the chemicals listed in 40 Code of Federal Regulations 60.489 (effective October 18, 1983).

(26) Tank-truck tank--Any storage tank having a capacity greater than 1,000 gallons, mounted on a tank-truck or trailer. Vacuum trucks used exclusively for maintenance and spill response are not considered to be tank-truck tanks.

(27) Transport vessel--Any land-based mode of transportation (truck or rail) that is equipped with a storage tank having a capacity greater than 1,000 gallons which is used to transport oil, gasoline, or other volatile organic liquid bulk cargo. Vacuum trucks used exclusively for maintenance and spill response are not considered to be transport vessels.

(28) True partial pressure--The absolute aggregate partial pressure (psia) of all VOC in a gas stream.

(29) Vapor balance system--A system which provides for containment of hydrocarbon vapors by returning displaced vapors from the receiving vessel back to the originating vessel.

(30) Vapor control system or vapor recovery system--Any control system which utilizes vapor collection equipment to route VOC to a control device that reduces VOC emissions.

(31) Vapor-tight--Not capable of allowing the passage of gases at the pressures encountered except where other acceptable leak-tight conditions are prescribed in this chapter.

(32) Waxy, high pour point crude oil--A crude oil with a pour point of 50 degrees Fahrenheit (10 degrees Celsius) or higher as determined by the American Society for Testing and Materials Standard D97-66, "Test for Pour Point of Petroleum Oils."

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009089
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

SUBCHAPTER B. GENERAL VOLATILE ORGANIC COMPOUND SOURCES
DIVISION 2. VENT GAS CONTROL

30 TAC §§115.120, 115.122, 115.125 - 115.127, 115.129

STATUTORY AUTHORITY

The new section and amendments are adopted under the Texas Health and Safety Code, Texas Clean Air Act (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.

§115.122. Control Requirements.

(a) For all persons in the Beaumont/Port Arthur, Dallas/Fort Worth, El Paso, and Houston/Galveston areas, the following control requirements shall apply:

(1) Any vent gas streams affected by §115.121(a)(1) of this title (relating to Emission Specifications) must be controlled properly with a control efficiency of at least 90% or to a volatile organic compound (VOC) concentration of no more than 20 parts per million by volume (ppmv) (on a dry basis corrected to 3.0% oxygen for combustion devices):

(A) in a direct-flame incinerator at a temperature equal to or greater than 1,300 degrees Fahrenheit (704 degrees Celsius);

(B) in a smokeless flare; or

(C) by any other vapor control system, as defined in §115.10 of this title (relating to Definitions).

(2) Any vent gas streams affected by §115.121(a)(2) of this title must be controlled properly with a control efficiency of at least 98% or to a VOC concentration of no more than 20 ppmv (on a dry basis corrected to 3.0% oxygen for combustion devices):

(A) in a smokeless flare; or

(B) by any other vapor control system, as defined in §115.10 of this title.

(3) For the Dallas/Fort Worth, El Paso, and Houston/Galveston areas, VOC emissions from each bakery with a bakery oven vent gas stream(s) affected by §115.121(a)(3) of this title shall be reduced as follows.

(A) Each bakery in the Houston/Galveston area with a total weight of VOC emitted from all bakery ovens on the property, when uncontrolled, equal to or greater than 25 tons per calendar year shall ensure that the overall emission reduction from the uncontrolled VOC emission rate of the oven(s) will be at least 80% by December 31, 2001.

(B) Each bakery in the Dallas/Fort Worth area with a total weight of VOC emitted from all bakery ovens on the property, when uncontrolled, equal to or greater than 50 tons per calendar year, shall ensure that the overall emission reduction from the uncontrolled VOC emission rate of the oven(s) will be at least 80% by December 31, 2000.

(C) Each bakery in the Dallas/Fort Worth area with a total weight of VOC emitted from all bakery ovens on the property, when uncontrolled, equal to or greater than 25 tons per calendar year, but less than 50 tons per calendar year, shall reduce total VOC emissions by at least 30% from the bakery's 1990 emissions inventory in accordance with the schedule specified in §115.129(d) of this title (relating to Counties and Compliance Schedules).

(D) Each bakery in the El Paso area with a total weight of VOC emitted from all bakery ovens on the property, when uncontrolled, equal to or greater than 25 tons per calendar year shall reduce total VOC emissions by at least 30% from the bakery's 1990 emissions inventory in accordance with the schedule specified in §115.129(e) of this title.

(E) Emission reductions in the 30% to 90% range are not creditable under Chapter 101, Subchapter H, Division 1 of this title (relating to Emission Credit Banking and Trading) for the following bakeries:

(i) each bakery in the Houston/Galveston area with a total weight of VOC emitted from all bakery ovens on the property, when uncontrolled, equal to or greater than 25 tons per calendar year;

(ii) each bakery in the Dallas/Fort Worth area with a total weight of VOC emitted from all bakery ovens on the property, when uncontrolled, equal to or greater than 50 tons per calendar year;

(iii) each bakery in the El Paso area with a total weight of VOC emitted from all bakery ovens on the property, when uncontrolled, equal to or greater than 50 tons per calendar year.

(4) Any vent gas stream that becomes subject to the provisions of paragraphs (1), (2), or (3) of this subsection by exceeding provisions of §115.127(a) of this title (relating to Exemptions) shall remain subject to the provisions of this subsection, even if throughput or emissions later fall below the exemption limits unless and until emissions are reduced to no more than the controlled emissions level existing before implementation of the project by which throughput or emission rate was reduced to less than the applicable exemption limits in §115.127(a) of this title; and:

(A) the project by which throughput or emission rate was reduced is authorized by any permit or permit amendment or standard permit or permit by rule required by Chapter 116 or Chapter 106 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification; and Permits by Rule). If a permit by rule is available for the project, compliance with this subsection must be maintained for 30 days after the filing of documentation of compliance with that permit by rule; or

(B) if authorization by permit, permit amendment, standard permit, or permit by rule is not required for the project, the owner or operator has given the executive director 30 days' notice of the project in writing.

(b) For all persons in Nueces and Victoria Counties, any vent gas streams affected by §115.121(b) of this title must be controlled properly with a control efficiency of at least 90% or to a VOC concentration of no more than 20 ppmv (on a dry basis corrected to 3.0% oxygen for combustion devices):

(1) in a direct-flame incinerator at a temperature equal to or greater than 1,300 degrees Fahrenheit (704 degrees Celsius);

(2) in a smokeless flare; or

(3) by any other vapor control system, as defined in §115.10 of this title.

(c) For all persons in Aransas, Bexar, Calhoun, Matagorda, San Patricio, and Travis Counties, the following control requirements shall apply.

(1) Any vent gas streams affected by §115.121(c)(1) of this title must be controlled properly:

(A) in a direct-flame incinerator at a temperature equal to or greater than 1,300 degrees Fahrenheit (704 degrees Celsius);

(B) in a smokeless flare; or

(C) by any other vapor control system, as defined in §115.10 of this title, with a control efficiency of at least 90% or to a VOC concentration of no more than 20 ppmv (on a dry basis corrected to 3.0% oxygen for combustion devices).

(2) Any vent gas streams affected by §115.121(c)(2) of this title must be controlled properly:

(A) in a direct-flame incinerator or boiler at a temperature equal to or greater than 1,300 degrees Fahrenheit (704 degrees Celsius); or

(B) by any other vapor control system, as defined in §115.10 of this title, with a control efficiency of at least 90% or to a VOC concentration of no more than 20 ppmv (on a dry basis corrected to 3.0% oxygen for combustion devices).

(3) Any vent gas streams affected by §115.121(c)(3) of this title must be controlled properly:

(A) at a temperature equal to or greater than 1,300 degrees Fahrenheit (704 degrees Celsius) in an afterburner having a retention time of at least one-fourth of a second, and having a steady flame that is not affected by the cupola charge and relights automatically if extinguished; or

(B) by any other vapor control system, as defined in §115.10 of this title, with a control efficiency of at least 90% or to a VOC concentration of no more than 20 ppmv (on a dry basis corrected to 3.0% oxygen for combustion devices).

(4) Any vent gas streams affected by §115.121(c)(4) of this title must be controlled properly:

(A) in a smokeless flare or in a combustion device used in a heating process associated with the operation of a blast furnace; or

(B) by any other vapor control system, as defined in §115.10 of this title, with a control efficiency of at least 90% or to a VOC concentration of no more than 20 ppmv (on a dry basis corrected to 3.0% oxygen for combustion devices).

§115.125. Testing Requirements.

Compliance with the emission specifications, vapor control system efficiency, and certain control requirements and exemption criteria of §§115.121 - 115.123 and 115.127 of this title (relating to Emission Specifications; Control Requirements; Alternate Control Requirements; and Exemptions) shall be determined by applying one or more of the following test methods and procedures, as appropriate, when specifically required within this division (relating to Vent Gas Control), when required by the executive director under §101.8 of this title (relating to Sampling), or when the owner or operator elects to conduct testing of one or more vent gas streams.

(1) Flow rate. Test Methods 1-4 (40 Code of Federal Regulations (CFR) 60, Appendix A) are used for determining flow rates, as necessary.

(2) Concentration of volatile organic compounds (VOC).

(A) Test Method 18 (40 CFR 60, Appendix A) is used for determining gaseous organic compound emissions by gas chromatography.

(B) Test Method 25 (40 CFR 60, Appendix A) is used for determining total gaseous nonmethane organic emissions as carbon.

(C) Test Methods 25A or 25B (40 CFR 60, Appendix A) are used for determining total gaseous organic concentrations using flame ionization or nondispersive infrared analysis.

(3) Performance requirements for flares and vapor combustors.

(A) For flares, Test Method 22 (40 CFR 60, Appendix A) is used for visual determination of fugitive emissions from material sources and smoke emissions.

(B) For flares, additional test method requirements are described in 40 CFR 60.18(f), unless EPA or the executive director has granted a waiver from such testing requirements.

(C) Flares in the Beaumont/Port Arthur, Dallas/Fort Worth, and Houston/Galveston areas shall comply with the performance test requirements of 40 CFR 60.18(b), unless EPA or the executive director has granted a waiver from such testing requirements.

(D) For vapor combustors, the owner or operator may consider the unit to be a flare. Each vapor combustor in Victoria County and the Beaumont/Port Arthur, Dallas/Fort Worth, El Paso, and Houston/Galveston areas which the owner or operator elected to consider as a flare shall meet the performance test requirements of 40 CFR 60.18(b) in lieu of any testing under paragraphs (1) and (2) of this section.

(E) Compliance with the requirements of 40 CFR 60.18(b) will be considered to demonstrate compliance with the emission specifications and control efficiency requirements of §115.121 and §115.122 of this title.

(4) Minor modifications. Minor modifications to these test methods may be used, if approved by the executive director.

(5) Alternate test methods. Test methods other than those specified in paragraphs (1) - (3) of this section may be used if validated by 40 CFR 63, Appendix A, Test Method 301 (effective December 29, 1992). For the purposes of this paragraph, substitute "executive director" each place that Test Method 301 references "administrator."

§115.126. Monitoring and Recordkeeping Requirements.

The owner or operator of any facility which emits volatile organic compounds (VOC) through a stationary vent in Aransas, Bexar, Calhoun, Matagorda, Nueces, San Patricio, Travis, and Victoria Counties or in the Beaumont/Port Arthur, Dallas/Fort Worth, El Paso, and Houston/Galveston areas shall maintain the following information at the facility for at least two years. The owner or operator shall make the information available upon request to representatives of the executive director, EPA, or any local air pollution control agency having jurisdiction in the area.

(1) Vapor control systems. For vapor control systems used to control emissions in Victoria County and in the Beaumont/Port Arthur, Dallas/Fort Worth, El Paso, and Houston/Galveston areas from vents subject to the provisions of §115.121 of this title (relating to Emission Specifications), records of appropriate parameters to demonstrate compliance, including:

(A) continuous monitoring and recording of:

(i) the exhaust gas temperature immediately downstream of a direct-flame incinerator;

(ii) the inlet and outlet gas temperatures of a catalytic incinerator or chiller;

(iii) the exhaust gas VOC concentration of any carbon adsorption system, as defined in §101.1 of this title (relating to Definitions); and

(iv) the exhaust gas temperature immediately downstream of a vapor combustor. Alternatively, the owner or operator of a vapor combustor may consider the unit to be a flare and meet the requirements specified in 40 Code of Federal Regulations (CFR) 60.18(b) and Chapter 111 of this title (relating to Control of Air Pollution from Visible Emissions and Particulate Matter) for flares;

(B) in the Beaumont/Port Arthur, Dallas/Fort Worth, and Houston/Galveston areas, the requirements specified in 40 CFR 60.18(b) and Chapter 111 of this title for flares; and

(C) for vapor control systems other than those specified in subparagraphs (A) and (B) of this paragraph, records of appropriate operating parameters.

(2) Test results. A record of the results of any testing conducted in accordance with §115.125 of this title (relating to Testing Requirements).

(3) Records for exempted vents. Records for each vent exempted from control requirements in accordance with §115.127 of this title (relating to Exemptions) shall be sufficient to demonstrate compliance with the applicable exemption limit, including the following, as appropriate:

(A) the pounds of ethylene emitted per 1,000 pounds of low-density polyethylene produced;

(B) the combined weight of VOC of each vent gas stream on a daily basis;

(C) the concentration of VOC in each vent gas stream on a daily basis;

(D) the maximum design flow rate or VOC concentration of each vent gas stream exempt under §115.127(a)(4)(C) of this title; and

(E) the total design capacity of process units exempt under §115.127(a)(4)(B) of this title.

(4) Alternative records for exempted vents. As an alternative to the requirements of paragraph (3)(B) and (C) of this section, records for each vent exempted from control requirements in accordance with §115.127 of this title and having a VOC emission rate or concentration less than the applicable exemption limits at maximum actual operating conditions shall be sufficient to demonstrate continuous compliance with the applicable exemption limit. These records shall include complete information from either test results or appropriate calculations which clearly documents that the emission characteristics at maximum actual operating conditions are less than the applicable exemption limit. This documentation shall include the operating parameter levels that occurred during any testing, and the maximum levels feasible (either VOC concentration or mass emission rate) for the process.

(5) Bakeries. For bakeries subject to §115.122(a)(3)(A) - (B) of this title (relating to Control Requirements), the following additional requirements apply.

(A) The owner or operator of each bakery in the Houston/Galveston area with a total weight of VOC emitted from all bakery ovens on the property, when uncontrolled, equal to or greater than 25 tons per calendar year, shall submit a control plan no later than March 31, 2001, to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction. The plan shall demonstrate that the overall emission reduction from the uncontrolled VOC emission rate of the oven(s) will be at least 80% by December 31, 2001. At a minimum, the control plan shall include the emission point number (EPN) and the facility identification number (FIN) of each bakery oven and any associated control device, a plot plan showing the location, EPN, and FIN of each bakery oven and any associated control device, and the 2000 VOC emission rates (consistent with the bakery's 2000 emissions inventory). The projected 2002 VOC emission rates shall be calculated in a manner consistent with the 2000 emissions inventory.

(B) All representations in control plans become enforceable conditions. It shall be unlawful for any person to vary from such representations if the variation will cause a change in the identity of the specific emission sources being controlled or the method of control of emissions unless the owner or operator of the bakery submits a revised control plan to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction within 30 days of the change. All control plans shall include documentation that the overall emission reduction from the uncontrolled VOC emission rate of the bakery's oven(s) continues to be at least the specified percentage reduction. The emission rates shall be calculated in a manner consistent with the most recent emissions inventory.

(6) Bakeries (contingency measures). For bakeries subject to §115.122(a)(3)(C) and (D) of this title, the following additional requirements apply.

(A) No later than six months after the commission publishes notification in the *Texas Register* as specified in §115.129(d) or (e) of this title (relating to Counties and Compliance Schedules), the owner or operator of each bakery shall 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 VOC emissions from the bakery's 1990 emissions inventory will be at least 30%. At a minimum, the control plan shall include the EPN and the FIN of each bakery oven and any associated control device, a plot plan showing the location, EPN, and FIN of each bakery oven and any associated control device, and the 1990 VOC emission rates (consistent with the bakery's 1990 emissions inventory). The projected VOC emission rates shall be calculated in a manner consistent with the 1990 emissions inventory.

(B) In order to document continued compliance with §115.122(a)(3) of this title, the owner or operator of each bakery 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 VOC emissions from the bakery's 1990 emissions inventory during the preceding calendar year is at least 30%. At a minimum, the report shall include the EPN and FIN of each bakery oven and any associated control device, a plot plan showing the location, EPN, and FIN of each bakery oven and any associated control device, and the VOC emission rates. The emission rates for the proceeding calendar year shall be calculated in a manner consistent with the 1990 emissions inventory.

(C) All representations in control plans and annual reports become enforceable conditions. It shall be unlawful for any person to vary from such representations if the variation will cause a change in the identity of the specific emission sources being controlled or the method of control of emissions unless the owner or operator of the bakery submits a revised control plan to the executive director, the appropriate regional office, and any local air pollution control program with jurisdiction within 30 days of the change. All control plans and reports shall include documentation that the overall reduction of VOC emissions from the bakery's 1990 emissions inventory continues to be at least 30%. The emission rates shall be calculated in a manner consistent with the 1990 emissions inventory.

(7) Additional flare requirements. The owner or operator of a facility that uses a flare to meet the requirements of §115.122(a)(2) of this title shall install, calibrate, maintain, and operate according to the manufacturer's specifications, a heat-sensing device, such as an ultraviolet beam sensor or thermocouple, at the pilot light to indicate continuous presence of a flame.

§115.129. Counties and Compliance Schedules.

(a) The owner or operator of each vent gas stream in Aransas, Bexar, Brazoria, Calhoun, Chambers, Collin, Dallas, Denton, El Paso, Fort Bend, Galveston, Hardin, Harris, Jefferson, Liberty, Matagorda, Montgomery, Nueces, Orange, San Patricio, Tarrant, Travis, Victoria, and Waller Counties shall continue to comply with this division (relating to Vent Gas Control) as required by §115.930 of this title (relating to Compliance Dates).

(b) The owner or operator of each bakery in Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties shall comply with §§115.121(a)(3), 115.122(a)(3), and 115.126(5) of this title (relating to Emission Specifications; Control Requirements; and Monitoring and Recordkeeping Requirements) as soon as practicable, but no later than December 31, 2001.

(c) The owner or operator of each bakery in Collin, Dallas, Denton, and Tarrant Counties subject to §115.122(a)(3)(B) of this title shall comply with §§115.121(a)(3), 115.122(a)(3), and 115.126(5) of this title as soon as practicable, but no later than December 31, 2000.

(d) The owner or operator of each bakery in Collin, Dallas, Denton, and Tarrant Counties subject to §115.122(a)(3)(C) of this title shall comply with §§115.121(a)(3), 115.122(a)(3)(C), and 115.126(6) of this title as soon as practicable, but no later than one year, after the commission publishes notification in the *Texas Register* of its determination that this contingency rule is necessary as a result of failure to attain the national ambient air quality standard (NAAQS) for ozone by the attainment deadline or failure to demonstrate reasonable further progress as set forth in the FCAA, §172(c)(9).

(e) The owner or operator of each bakery in El Paso County subject to §115.122(a)(3)(D) of this title shall comply with §§115.121(a)(3), 115.122(a)(3)(D), and 115.126(6) of this title as soon as practicable, but no later than one year, after the commission publishes notification in the *Texas Register* of its determination that this contingency rule is necessary as a result of failure to attain the NAAQS for ozone by the attainment deadline or failure to demonstrate reasonable further progress as set forth in the FCAA, §172(c)(9).

(f) The owner or operator of each flare in Brazoria, Chambers, Collin, Dallas, Denton, Fort Bend, Galveston, Hardin, Harris, Jefferson, Liberty, Montgomery, Orange, Tarrant, and Waller Counties which is used to comply with the requirements of §115.121 and/or §115.122 of this title shall comply with §115.125(3)(C) and §115.126(1)(B) of this title (relating to Testing Requirements; and Monitoring and Recordkeeping Requirements) as soon as practicable, but no later than December 31, 2001.

(g) The owner or operator of each vent gas stream in Aransas, Bexar, Calhoun, Matagorda, San Patricio, and Travis Counties shall comply with the recordkeeping requirements of §115.126(3) and (4) of this title as soon as practicable, but no later than December 31, 2001.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009090

Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

DIVISION 6. BATCH PROCESSES

30 TAC §§115.161, 115.162, 115.164 - 115.167, 115.169

STATUTORY AUTHORITY

The amendments are adopted under the Texas Health and Safety Code, Texas Clean Air Act, (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.

§115.162. Control Requirements.

The owner or operator of each batch process operation in the Beaumont/Port Arthur and Houston/Galveston areas shall comply with the following control requirements.

(1) Reasonable available control technology (RACT) equations. The volatile organic compounds (VOC) mass emission rate from individual process vents or for process vent streams in aggregate within a batch process shall be reduced by 90% if the actual average flow rate value (in standard cubic feet per minute (scfm)) is below the flow rate (FR) value calculated using the applicable RACT equation for the volatility range (low, moderate, or high) of the material being emitted when the annual mass emission total (AE, in pounds per year) are input. The RACT equations, specific to volatility, are as follows:

(A) Low volatility: FR = 0.07(AE) - 1821;

(B) Moderate volatility: FR = 0.031(AE) - 494;

(C) High volatility: FR = 0.013(AE) - 301.

(2) Successive ranking scheme. For aggregate streams within a process, the control requirements must be evaluated with the following successive ranking scheme until control of a segment of unit operations is required or until all unit operations have been eliminated from the process pool.

(A) If, for the process vent streams in aggregate, the value of FR calculated using the applicable RACT equation in paragraph (1) of this section is negative (i.e., less than zero), then the process is exempt from the 90% control requirements, and the successive ranking scheme of subparagraph (F) of this paragraph does not apply. This would occur if the mass annual emission rates are below the lower limits specified in §115.167(2)(A) of this title (relating to Exemptions).

(B) If, for the process vent streams in aggregate, the actual average flow rate value (in scfm) is below the value of FR calculated using the applicable RACT equation in paragraph (1) of this section, then the overall emissions from the batch process must be reduced by 90%, and the successive ranking scheme of subparagraph (F) of this paragraph does not apply. The owner or operator has the option of selecting which unit operations are to be controlled and to what levels, provided that the overall control meets the specified level of 90%. Single units that qualify for exemption under §115.167(2)(B) of this title do not have to be controlled even if all units should qualify for this exemption.

(C) If, for the process vent streams in aggregate, the actual average flow rate value (in scfm) is greater than the value of FR calculated using the applicable RACT equation in paragraph (1) of this section (and the calculated value of FR is a positive number), then the control requirements must be evaluated with the successive ranking scheme of subparagraph (F) of this paragraph until control of a segment of unit operations is required or until all unit operations have been eliminated from the process pool. Single units that qualify for exemption under §115.167(2)(B) of this title do not have to be included in the rankings and do not have to be controlled.

(D) Sources that are required to be controlled to the level specified by RACT (i.e., 90%) will have an average flow rate that is below the flow rate specified by the applicable RACT equation in paragraph (1) of this section (when the source's annual emission total is input). The applicability criterion is implemented on a two-tier basis. First, single pieces of batch equipment corresponding to distinct unit operations shall be evaluated over the course of an entire year, regardless of what materials are handled or what products are manufactured in them. Second, equipment shall be evaluated as an aggregate if it can be linked together based on the definition of a process.

(E) To determine applicability of a RACT option in the aggregation scenario, all the VOC emissions from a single process shall be summed to obtain the annual mass emission total, and the weighted average flow rate from each process vent in the aggregation shall be used as the average flow rate.

(F) All unit operations in the batch process, as defined for the purpose of determining RACT applicability, shall be ranked in ascending order according to their ratio of annual emissions (pounds per year) divided by average flow rate (in scfm). Sources with the smallest ratios shall be listed first. This list of sources constitutes the "pool" of sources within a batch process. The annual emission total and average flow rate of the pool of sources shall then be compared against the RACT equations in paragraph (1) of this section to determine whether control of the pool is required.

(i) If control is not required after the initial ranking, unit operations having the lowest annual emissions/average flow rate ratio shall then be eliminated one by one, and the characteristics of annual emission and average flow rate for the remaining pool of equipment must be evaluated with each successive elimination of a source from the pool.

(ii) Control of the unit operations remaining in the pool to the specified level (i.e., 90%) shall be required once the aggregated characteristics of annual emissions and average flow rate have met the specified cutoffs. The owner or operator has the option of selecting which unit operations are to be controlled and to what levels, provided that the overall control meets the specified level of 90%.

(3) Once-in, always-in. Any batch process operation that becomes subject to the provisions of this division by exceeding provisions of §115.167 of this title will remain subject to the provision of this division, even if throughput or emissions later fall below exemption limits, unless and until emissions are reduced to no more than the controlled emissions level existing before implementation of the project by which throughput or emission rate was reduced to less than the applicable exemption limits in §115.167 of this title; and

(A) the project by which throughput or emission rate was reduced is authorized by any permit or permit amendment or standard permit or permit by rule required by Chapter 116 or Chapter 106 of this title (relating to Control of Air Pollution by Permits for New

Construction or Modification; and Permits by Rule). If a permit by rule is available for the project, compliance with this division must be maintained for 30 days after the filing of documentation of compliance with that permit by rule; or

(B) if authorization by permit, permit amendment, standard permit, or permit by rule is not required for the project, the owner/operator has given the executive director 30 days' notice of the project in writing.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009091
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

SUBCHAPTER C. VOLATILE ORGANIC COMPOUND TRANSFER OPERATIONS
DIVISION 1. LOADING AND UNLOADING OF VOLATILE ORGANIC COMPOUNDS

30 TAC §§115.211, 115.212, 115.216

STATUTORY AUTHORITY

The amendments are adopted under the Texas Health and Safety Code, Texas Clean Air Act (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.

§115.212. Control Requirements.

(a) The owner or operator of each volatile organic compound (VOC) transfer operation, transport vessel, and marine vessel in the Beaumont/Port Arthur, Dallas/Fort Worth, El Paso, and Houston/Galveston areas shall comply with the following control requirements.

(1) General VOC loading. At VOC loading operations other than gasoline terminals, gasoline bulk plants, and marine terminals, vapors from the transport vessel caused by the loading of VOC with a true vapor pressure greater than or equal to 0.5 psia under actual storage conditions must be controlled by:

(A) a vapor control system which maintains a control efficiency of at least 90%; or

(B) a vapor balance system, as defined in §115.10 of this title (relating to Definitions); or

(C) pressurized loading.

(2) Disposal of transported vapors. After unloading, transport vessels must be kept vapor-tight until the vapors in the transport vessel are returned to a loading, cleaning, or degassing operation and discharged in accordance with the control requirements of that operation.

(3) Leak-free requirements. All land-based VOC transfer to or from transport vessels shall be conducted such that:

(A) All liquid and vapor lines are:

(i) equipped with fittings which make vapor-tight connections that close automatically when disconnected; or

(ii) equipped to permit residual VOC after transfer is complete to discharge into a recovery or disposal system which routes all VOC emissions to a vapor control system or a vapor balance system. After VOC transfer, if necessary to empty a liquid line, the contents may be placed in a portable container, which is then closed vapor-tight and disposed of properly.

(B) There are no VOC leaks, as defined in §101.1 of this title (relating to Definitions), when measured with a hydrocarbon gas analyzer, and no liquid or vapor leaks, as detected by sight, sound, or smell, from any potential leak source in the transport vessel and transfer system (including, but not limited to, liquid lines, vapor lines, hatch covers, pumps, and valves, including pressure relief valves).

(C) All gauging and sampling devices are vapor-tight except for necessary gauging and sampling. Any nonvapor-tight gauging and/or sampling shall:

(i) be limited in duration to the time necessary to practicably gauge and/or sample; and

(ii) not occur while VOC is being transferred.

(D) Any openings in a transport vessel during unloading are limited to minimum openings which are sufficient to prevent collapse of the transport vessel.

(E) If VOC is loaded through the hatches of a transport vessel, then pneumatic, hydraulic, or other mechanical means shall force a vapor-tight seal between the loading arm's vapor collection adapter and the hatch. A means shall be provided which prevents liquid drainage from the loading device when it is removed from the hatch of any transport vessel, or which routes all VOC emissions to a vapor control system. After VOC transfer, if necessary to empty a liquid line, the contents may be placed in a portable container, which is then closed vapor-tight and disposed of properly.

(4) Gasoline terminals. The following additional control requirements apply to the transfer of gasoline at gasoline terminals.

(A) A vapor control system must be used to control the vapors from loading each transport vessel.

(B) Vapor control systems and loading equipment at gasoline terminals shall be designed and operated such that gauge pressure does not exceed 18 inches of water and vacuum does not exceed six inches of water in the gasoline tank-truck.

(C) Each gasoline terminal shall be equipped with sensors and other equipment designed and connected to monitor the status of the control device. If the control device malfunctions or is not operational, the system shall automatically stop gasoline transfer to the transport vessel(s) immediately.

(D) As an alternative to subparagraph (C) of this paragraph, the following requirements apply to gasoline terminals which have a variable vapor space holding tank design that can process the vapors independent of transport vessel loading. Such gasoline terminals shall be equipped with sensors and other equipment designed and connected to monitor the status of the control device. If the variable vapor space holding tank serving the loading rack(s) does not have the capacity to store additional vapors for processing by the control device at a later time and the control device malfunctions or is not operational, the system shall automatically stop gasoline transfer to the transport vessel(s) immediately.

(5) Gasoline bulk plants. The following additional control requirements apply to transfer of gasoline at gasoline bulk plants.

(A) A vapor balance system must be used between the storage tank and transport vessel. Alternatively, a vapor control system which maintains a control efficiency of at least 90% may be used to control the vapors.

(B) While filling a transport vessel from a storage tank:

(i) the transport vessel, if equipped for top loading, must use a submerged fill pipe; and

(ii) gauge pressure must not exceed 18 inches of water and vacuum must not exceed six inches of water in the gasoline tank-truck tank.

(6) Marine terminals. The following control requirements apply to marine terminals in the Houston/Galveston area.

(A) VOC emissions shall not exceed 0.09 pound from the vapor control system vent per 1,000 gallons (10.8 mg/liter) of VOC loaded into the marine vessel, or the vapor control system shall maintain a control efficiency of at least 90%. Alternatively, a vapor balance system or pressurized loading may be used to control the vapors.

(B) Only leak-free marine vessels, as defined in §115.10 of this title, shall be used for loading operations.

(C) All gauging and sampling devices shall be vapor-tight except for necessary gauging and sampling. Any nonvapor-tight gauging and/or sampling shall:

(i) be limited in duration to the time necessary to practicably gauge and/or sample; and

(ii) not occur while VOC is being transferred.

(D) When non-dedicated loading lines are used to load VOC with a true vapor pressure less than 0.5 psia (or a flash point of 150 degrees Fahrenheit or greater) and the preceding transfer through these lines was VOC with a true vapor pressure equal to or greater than 0.5 psia, the residual VOC vapors from this preceding transfer must be controlled by the vapor control system, vapor balance system, or pressurized loading as specified in subparagraph (A) of this paragraph.

(7) Once-in-always-in. Any loading or unloading operation that becomes subject to the provisions of this subsection by exceeding provisions of §115.217(a) of this title (relating to Exemptions) will remain subject to the provision of this subsection, even if throughput or emissions later fall below exemption limits unless and until emissions are reduced to no more than the controlled emissions level existing before implementation of the project by which throughput or emission rate was reduced to less than the applicable exemption limits in §115.217(a) of this title; and

(A) the project by which throughput or emission rate was reduced is authorized by any permit or permit amendment or standard permit or permit by rule required by Chapter 116 or Chapter 106 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification; and Permits by Rule). If a permit by rule is available for the project, compliance with this subsection must be maintained for 30 days after the filing of documentation of compliance with that permit by rule; or

(B) if authorization by permit, permit amendment, standard permit, or permit by rule is not required for the project, the owner/operator has given the executive director 30 days' notice of the project in writing.

(b) The owner or operator of each land-based VOC transfer operation and transport vessel in the covered attainment counties shall comply with the following control requirements.

(1) General VOC loading in Aransas, Bexar, Calhoun, Gregg, Matagorda, Nueces, San Patricio, Travis, and Victoria Counties. At VOC loading operations other than gasoline terminals and gasoline bulk plants, vapors from the transport vessel caused by the loading of VOC with a true vapor pressure greater than or equal to 1.5 psia under actual storage conditions must be controlled by:

(A) a vapor control system which maintains a control efficiency of at least 90%;

(B) a vapor balance system, as defined in §115.10 of this title; or

(C) pressurized loading.

(2) Disposal of transported vapors. After unloading, transport vessels must be kept vapor-tight until the vapors in the transport vessel are returned to a loading, cleaning, or degassing operation and discharged in accordance with the control requirements of that operation.

(3) Leak-free requirements. All land-based VOC transfer to or from transport vessels shall be conducted such that:

(A) all liquid and vapor lines are:

(i) equipped with fittings which make vapor-tight connections and that close automatically when disconnected; or

(ii) equipped to permit residual VOC after transfer is complete to discharge into a recovery or disposal system which routes all VOC emissions to a vapor control system or a vapor balance system. After VOC transfer, if necessary to empty a liquid line, the contents may be placed in a portable container, which is then closed vapor-tight and disposed of properly.

(B) there are no VOC leaks, as defined in §101.1 of this title, when measured with a hydrocarbon gas analyzer, and no liquid or vapor leaks, as detected by sight, sound, or smell, from any potential leak source in the transport vessel and transfer system (including, but not limited to, liquid lines, vapor lines, hatch covers, pumps, and valves, including pressure relief valves);

(C) all gauging and sampling devices are vapor-tight except for necessary gauging and sampling. Any nonvapor-tight gauging and/or sampling shall:

(i) be limited in duration to the time necessary to practicably gauge and/or sample; and

(ii) not occur while VOC is being transferred;

(D) any openings in a transport vessel during unloading are limited to minimum openings which are sufficient to prevent collapse of the transport vessel;

(E) if VOC is loaded through the hatches of a transport vessel, then pneumatic, hydraulic, or other mechanical means shall force a vapor-tight seal between the loading arm's vapor collection adapter and the hatch. A means shall be provided which prevents liquid drainage from the loading device when it is removed from the hatch of any transport vessel, or which routes all VOC emissions to a vapor control system. After VOC transfer, if necessary to empty a liquid line, the contents may be placed in a portable container, which is then closed vapor-tight and disposed of properly.

(4) Gasoline terminals. The following additional control requirements apply to gasoline transfer at gasoline terminals.

(A) A vapor control system must be used to control the vapors from loading the transport vessel.

(B) Vapor control systems and loading equipment at gasoline terminals shall be designed and operated such that gauge pressure does not exceed 18 inches of water and vacuum does not exceed six inches of water in the gasoline tank-truck.

(C) Each gasoline terminal shall be equipped with sensors and other equipment designed and connected to monitor the status of the control device. If the control device malfunctions or is not operational, the system shall automatically stop gasoline transfer to the transport vessel(s) immediately.

(D) As an alternative to subparagraph (C) of this paragraph, the following requirements apply to gasoline terminals which have a variable vapor space holding tank design that can process the vapors independent of transport vessel loading. Such gasoline terminals shall be equipped with sensors and other equipment designed and connected to monitor the status of the control device. If the variable vapor space holding tank serving the loading rack(s) does not have the capacity to store additional vapors for processing by the control device at a later time and the control device malfunctions or is not operational, the system shall automatically stop gasoline transfer to the transport vessel(s) immediately.

(5) Gasoline bulk plants. The following additional control requirements apply to gasoline transfer at gasoline bulk plants.

(A) A vapor balance system must be used between the storage tank and transport vessel. Alternatively, a vapor control system which maintains a control efficiency of at least 90% may be used to control the vapors.

(B) While filling a transport vessel from a storage tank:

(i) the transport vessel, if equipped for top loading, must use a submerged fill pipe; and

(ii) gauge pressure must not exceed 18 inches of water and vacuum must not exceed six inches of water in the gasoline tank-truck tank.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009092
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

DIVISION 4. CONTROL OF VEHICLE REFUELING EMISSIONS (STAGE II) AT MOTOR VEHICLE FUEL DISPENSING FACILITIES

30 TAC §115.240

STATUTORY AUTHORITY

The new section is adopted under the Texas Health and Safety Code, Texas Clean Air Act (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.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009093
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

SUBCHAPTER E. SOLVENT-USING PROCESSES

DIVISION 3. FLEXOGRAPHIC AND ROTOGRAVURE PRINTING

30 TAC §115.430

STATUTORY AUTHORITY

The new section is adopted under the Texas Health and Safety Code, Texas Clean Air Act (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.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009094

Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

DIVISION 4. OFFSET LITHOGRAPHIC PRINTING

30 TAC §115.449

STATUTORY AUTHORITY

The amendment is adopted under the Texas Health and Safety Code, Texas Clean Air Act (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.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009095
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

SUBCHAPTER J. ADMINISTRATIVE PROVISIONS

DIVISION 4. EMISSIONS TRADING

30 TAC §115.950

The Texas Natural Resource Conservation Commission (commission) adopts the amendment to §115.950, Emissions Trading, *without changes* to the proposed text as published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8272) and therefore will not be republished. This amendment will be submitted as a revision to the Texas state implementation plan (SIP).

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULE In concurrent rulemaking, §101.29 is repealed and its requirements transferred and amended in new Chapter 101, Subchapter H, Divisions 1 and 4. This rulemaking amends §115.950 to cite the correct cross-reference. The amended section requires the user of credits to obtain additional emission reduction credits or achieve lower actual emissions if new lower volatile organic compound (VOC) emission specifications are established by future amendments to this chapter.

SECTION BY SECTION DISCUSSION

Section 115.950 is amended to change the title to "Use of Emissions Credits for Compliance" from "Emissions Trading" to more clearly reflect the language in §115.950, which discusses how to use emission reduction credits for alternative compliance, not how to trade emission reduction credits.

The adoption of §115.950(a) removes the reference to §101.29 and corrects the reference to Chapter 101, Subchapter H, Division 1, Emission Reduction Credit Banking and Trading, or Division 4, Discrete Emission Reduction Banking and Trading. In addition, the amendment clarifies that emission reduction credits (ERCs), mobile emission reduction credits (MERCs), discrete emission reduction credit (DERCs), or mobile discrete emission reduction credit (MDERCs) may be used to meet any of the requirements of Chapter 115. The term "RC" refers to an ERC, MERC, DERC, or MDERC.

Adopted §115.950(b) adds language requiring that owners or operators using Chapter 101, Subchapter H, Division 1 or Division 4 to meet the emission control requirements of Chapter 115 must obtain additional RCs or reduce actual emissions if any lower VOC emission specification is established by future amendments to Chapter 115.

FINAL REGULATORY IMPACT ANALYSIS

The commission has reviewed the adopted rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225. The commission has determined that the amendment to Chapter 115 does not meet the definition of a "major environmental rule" as defined in Texas Government Code, §2001.0225. "Major environmental rule" means a rule, the specific intent of which, is to protect the environment or reduce risks to human health from environmental exposure, and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, amendment to achieve administrative consistency with amendments to Chapter 101 adopted in concurrent rulemaking. The amendment to Chapter 115 does not add regulatory requirements, but is adopted to allow compliance flexibility in meeting current or future VOC emission limitations in Chapter 115. Therefore, there will be no adverse impact of this rule.

TAKINGS IMPACT ASSESSMENT

The commission has completed a takings impact assessment for the adopted rule. The following is a summary of that assessment. The commission is adopting the amendment to achieve administrative consistency with amendments to Chapter 101 adopted in concurrent rulemaking. The amendment to Chapter 115 does not add regulatory requirements, but allows compliance flexibility in meeting current or future VOC emission limitations in Chapter 115. The amendment does not affect private real property in a manner which restricts or limits an owner's right to the property that would otherwise exist in the absence of a governmental action. Consequently, the amended section does not meet the definition of a takings under Texas Government Code, §2007.002(5).

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission has determined the 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 the Texas Coastal Management Program. As required by 30 TAC §281.45(a)(3) and 31 TAC §505.11(b)(2), 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, and has determined that the rule is 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. The amendment to Chapter 115 does not add regulatory requirements, but is adopted to allow compliance flexibility in meeting current or future VOC emission limitations in Chapter 115.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMITS PROGRAM

Sources that currently have §115.590 listed in their federal operating permit would not be required to amend the permit in response to this amendment. However, those sources that wish to use RCs to comply with this chapter must revise their operating permit, consistent with the process in 30 TAC Chapter 122, to include the revised §115.590 requirements for each emission unit affected by §115.590 at their site.

PUBLIC HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000.

There were no comments on this specific amendment.

STATUTORY AUTHORITY

The amendment is adopted under Texas Health and Safety Code, TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to develop a plan for control of the state's air; §382.017, which provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA, and 42 United States Code, §7410(a)(2)(A), which requires SIPs to include enforceable emission limitations and other control measures or techniques, including economic incentives such as fees, marketable permits, and auction of emission rights.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009075

Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

CHAPTER 117. CONTROL OF AIR POLLUTION FROM NITROGEN COMPOUNDS

The Texas Natural Resource Conservation Commission (TNRCC or commission) adopts amendments to §117.10, concerning Definitions; §§117.101, 117.103, 117.105, 117.106, 117.108, 117.111, 117.113, 117.116, 117.119, and 117.121, concerning Utility Electric Generation in Ozone Nonattainment Areas; §117.138, concerning System Cap; §§117.201, 117.203, 117.205-117.208, 117.211, 117.213, 117.216, 117.219, and 117.221, concerning Industrial, Commercial, and Institutional Sources in Ozone Nonattainment Areas; and §117.510 and §117.520, concerning Administrative Provisions. The commission also adopts new §117.114 and §117.214, concerning Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration; §117.210, concerning System Cap; and §117.534, concerning Compliance Schedule for Boilers, Process Heaters, and Stationary Engines at Minor Sources. The commission also adopts new §§117.471, 117.473, 117.475, 117.478, and 117.479 in Subchapter D, which are being added as a new Division 2, concerning Boilers, Process Heaters, and Stationary Engines at Minor Sources. Sections 117.10, 117.103, 117.105, 117.106, 117.108, 117.114, 117.116, 117.121, 117.201, 117.203, 117.205, 117.206, 117.208, 117.210, 117.213, 117.214, 117.216, 117.219, 117.221, 117.473, 117.475, 117.478, 117.479, 117.510, 117.520, and 117.534 are adopted *with changes* to the proposed text as published in the August 25, 2000, issue of the *Texas Register* (25 TexReg 8275). Sections 117.101, 117.111, 117.113, 117.119, 117.138, 117.207, 117.211, and 117.471 are adopted *without changes* and will not be republished.

The revisions to Chapter 117 and to the state implementation plan (SIP) require a wide variety of stationary sources of nitrogen oxides (NO_x) emissions in the Houston/Galveston (HGA) ozone nonattainment area to meet new emission specifications and other requirements in order to reduce NO_x emissions and ozone air pollution. The affected equipment types and processes include electric utility boilers and stationary gas turbines; industrial, commercial, and institutional (ICI) boilers and stationary gas turbines; duct burners used in turbine exhaust ducts; process heaters and furnaces; stationary internal combustion (IC) engines; fluid catalytic cracking units (FCCUs), including catalyst regenerators and associated carbon monoxide (CO) boilers and furnaces; pulping liquor recovery furnaces; lime kilns; lightweight aggregate kilns; metallurgical heat treating furnaces and reheat furnaces; magnesium chloride fluidized bed dryers; incinerators, including enclosed control devices that combust or oxidize gases or vapors; and hazardous waste-fired boilers and industrial furnaces (BIF units).

The commission adopts these amendments to Chapter 117, concerning Control of Air Pollution from Nitrogen Compounds, and to the SIP as essential components of and consistent with the SIP that Texas is required to develop under the Federal Clean Air Act (FCAA) Amendments of 1990 (42 United States Code

(USC)), §7410, to demonstrate attainment of the national ambient air quality standard (NAAQS) for ozone. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. Another purpose of these amendments is to ensure that reasonably available control technology (RACT) requirements, as required by 42 USC, §7511a(f), are applied to major NO_x sources in HGA which are not subject to the previous NO_x RACT rules.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

The HGA ozone nonattainment area is classified as Severe-17 under the 1990 Amendments to the FCAA (42 USC, §§7401 et seq.), and therefore is required to attain the one-hour ozone standard of 0.12 parts per million (ppm) by November 15, 2007. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined by Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties, has been working to develop a demonstration of attainment in accordance with 42 USC, §7410. On January 4, 1995, the state submitted the first of its Post-1996 SIP revisions for HGA.

The January 1995 SIP consisted of urban airshed model (UAM) modeling for 1988 and 1990 base case episodes, adopted rules to achieve a 9% rate-of-progress (ROP) reduction in volatile organic compounds (VOC), and a commitment schedule for the remaining ROP and attainment demonstration elements. At the same time, but in a separate action, the State of Texas filed for the temporary NO_x waiver allowed by 42 USC, §7511a(f). The January 1995 SIP and the NO_x waiver were based on early base case episodes which marginally exhibited model performance in accordance with United States Environmental Protection Agency (EPA) modeling performance standards, but which had a limited data set as inputs to the model. In 1993 and 1994, the commission was engaged in an intensive data-gathering exercise known as the Coastal Oxidant Assessment for Southeast Texas (COAST) study. The commission believed that the enhanced emissions inventory, expanded ambient air quality and meteorological monitoring, and other elements would provide a more robust data set for modeling and other analysis, which would lead to modeling results that the commission could use to better understand the nature of the ozone air quality problem in the HGA area.

Around the same time as the 1995 submittal, EPA policy regarding SIP elements and timelines went through changes. Two national programs in particular resulted in changing deadlines and requirements. The first of these programs was the Ozone Transport Assessment Group (OTAG). This group grew out of a March 2, 1995 memo from Mary Nichols, former EPA Assistant Administrator for Air and Radiation, that allowed states to postpone completion of their attainment demonstrations until an assessment of the role of transported ozone and precursors had been completed for the eastern half of the nation, including the eastern portion of Texas. Texas participated in this study, and it has been concluded that Texas does not significantly contribute to ozone exceedances in the Northeastern United States. The other major national initiative that has impacted the SIP planning process is the revision to the national ozone standard. The EPA promulgated a final rule on July 18, 1997 changing the ozone standard to an eight-hour standard of 0.08 ppm. In November 1996, concurrent with the proposal of the standards, the EPA proposed an interim implementation plan (IIP) that it believed would help areas like HGA transition from the old to the new standard. In an attempt to avoid a significant delay in planning activities, Texas began to follow this guidance, and readjusted its modeling and SIP development timelines accordingly. When the new standard was published, the EPA decided not to publish the IIP, and instead stated that, for areas currently exceeding the one-hour ozone standard, that standard would continue to apply until it is attained. The FCAA requires that HGA attain the one-hour standard by November 15, 2007.

The EPA issued revised draft guidance for areas such as HGA that do not attain the one-hour ozone standard. The commission adopted on May 6, 1998 and submitted to the EPA on May 19, 1998 a revision to the HGA SIP which contained the following elements in response to EPA's guidance: UAM modeling based on emissions projected from a 1993 baseline out to the 2007 attainment date; an estimate of the level of VOC and NO_x reductions necessary to achieve the one-hour ozone standard by 2007; a list of control strategies that the state could implement to attain the one-hour ozone standard; a schedule for completing the other required elements of the attainment demonstration; a revision to the Post-1996 9% ROP SIP that remedied a deficiency that the EPA believed made the previous version of that SIP unapprovable; and evidence that all measures and regulations required by Subpart 2 of Title I of the FCAA to control ozone and its precursors have been adopted and implemented, or are on an expeditious schedule to be adopted and implemented.

In November 1998, the SIP revision submitted to the EPA in May 1998 became complete by operation of law. However, the EPA stated that it could not approve the SIP until specific control strategies were modeled in the attainment demonstration. The EPA specified a submittal date of November 15, 1999 for this modeling. In a letter to the EPA dated January 5, 1999, the state committed to model two strategies showing attainment.

As the HGA modeling protocol evolved, the commission eventually selected and modeled seven basic modeling scenarios. As part of this process, a group of HGA stakeholders worked closely with commission staff to identify local control strategies for the modeling. Some of the scenarios for which the stakeholders requested evaluation included options such as California-type fuel and vehicle programs as well as an acceleration simulation mode equivalent motor vehicle inspection and maintenance program. Other scenarios incorporated the estimated reductions in emissions that were expected to be achieved throughout the modeling domain as a result of the implementation of several voluntary and mandatory state-wide programs adopted or planned independently of the SIP. It should be made clear that the commission did not propose that any of these strategies be included in the ultimate control strategy submitted to the EPA in 2000. The need for and effectiveness of any controls which may be implemented outside the HGA eight-county area will be evaluated on a county-by-county basis.

The SIP revision was adopted by the commission on October 27, 1999, submitted to the EPA by November 15, 1999, and contained the following elements: photochemical modeling of potential specific control strategies for attainment of the one-hour ozone standard in the HGA area by the attainment date of November 15, 2007; an analysis of seven specific modeling scenarios reflecting various combinations of federal, state, and local controls in HGA (additional scenarios H1 and H2 build upon

Scenario VIf); identification of the level of reductions of VOC and NO_x necessary to attain the one-hour ozone standard by 2007; a 2007 mobile source budget for transportation conformity; identification of specific source categories which, if controlled, could result in sufficient VOC and/or NO_x reductions to attain the standard; a schedule committing to submit by April 2000 an enforceable commitment to conduct a mid-course review; and a schedule committing to submit modeling and adopted rules in support of the attainment demonstration by December 2000.

The April 19, 2000 SIP revision for HGA contained the following enforceable commitments by the state: to quantify the shortfall of NO_x reductions needed for attainment; to list and quantify potential control measures to meet the shortfall of NO_x reductions needed for attainment; to adopt the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000, and to adopt the rest of the shortfall rules as expeditiously as practical, but no later than July 31, 2001; to submit a Post-99 ROP plan by December 31, 2000; to perform a mid-course review by May 1, 2004; and to perform modeling of mobile source emissions using the EPA mobile source emissions model (MOBILE6), to revise the on-road mobile source budget as needed, and to submit the revised budget within 24 months of the model's release. In addition, if a conformity analysis is to be performed between 12 months and 24 months after the MOBILE6 release, the state will revise the motor vehicle emissions budget (MVEB) so that the conformity analysis and the SIP MVEB are calculated on the same basis.

In order for the state to have an approvable attainment demonstration, EPA has indicated that the state must adopt those strategies modeled in the November 15, 1999 submittal and then adopt sufficient controls to close the remaining gap in NO_x emissions. The predicted emission reductions from these rules are necessary to successfully demonstrate attainment.

The emission reduction requirements included as part of this SIP revision represent substantial, intensive efforts on the part of stakeholder coalitions in the HGA area. These coalitions, involving local governmental entities, elected officials, environmental groups, industry, consultants, and the public, as well as the commission and the EPA, have worked diligently to identify and quantify potential control strategy measures for the HGA attainment demonstration. Local officials from the HGA area have formally submitted a resolution to the commission, requesting the inclusion of many specific emission reduction strategies.

This rule adoption is one element of the control strategy for the HGA SIP. Adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Additional elements of the control strategy for the HGA SIP are being adopted concurrently in this issue of the *Texas Register*, or were included in the HGA SIP considered by the commission on December 6, 2000 and planned to be submitted to the EPA by December 31, 2000.

The amount of NO_x reductions required for the area to attain the ozone NAAQS has 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 reduction strategies. The FCAA, 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 oversight committee. Commission staff have continued to improve the air quality modeling technology and refine emission inventory data. Numerous emission control strategies were considered in developing the modeling. Varying degrees of reductions from point sources, on-road and non-road mobile sources, and area sources were analyzed in multiple iterations of modeling, to test the effectiveness of different NO_x reductions. The attainment demonstration modeling and other analysis submitted for public hearing and comment concurrently with these rules show that close to the maximum NO_x reductions practicably achievable are necessary from each ozone control strategy in order for HGA to achieve the ozone NAAQS by 2007, including reductions from surrounding counties included in the HGA consolidated metropolitan statistical area (CMSA). Therefore, each strategy, including the reductions required by this rulemaking, is crucial to meeting federal requirements for the HGA nonattainment area.

Additionally, reductions associated with the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies. At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The current SIP revision contains rules, enforceable commitments, photochemical modeling analyses, and calculation of the remaining NO_x reductions required to reach attainment (gap calculation) in support of the HGA ozone attainment demonstration. In addition, this SIP contains Post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contains enforceable commitments to implement further measures, if needed, in support of the HGA attainment demonstration, as well as a commitment to perform and submit a mid-course review.

The Houston nonattainment area will need to ultimately reduce NO_x more than 750 tpd to reach attainment with the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of point source NO_x rules will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area.

The attainment demonstration modeling produces a target emission rate of 98 tons of NO_x per day in 2007 from industrial point sources. This number includes emissions from new facilities which started operation after 1997, banked emission reduction credits, and future facilities permitted or with permit applications administratively complete by January 1, 2001. The staff analyzed the most recent available point source NO_x emissions inventory, from 1997, categorizing the emitting sources by equipment type to identify how to reasonably obtain the necessary reductions. In the Tables and Graphics section of this issue of the *Texas Register*, the table titled "Potential NO_x Emission Reductions by Point Source Category for Houston/Galveston

Nonattainment Area Counties" indicates the relative proportion of emissions according to equipment category.

Figure 1: 30 TAC Chapter 117 - Preamble

Another table in the Tables and Graphics section of this issue of the *Texas Register*, titled "Subcategories-Point Source Potential NO_x Emission Reductions for Houston/Galveston Nonattainment Area Counties," further breaks down the equipment categories and indicates the estimated NO_x emission reductions which would result from implementation of the proposed Chapter 117 rules.

Figure 2: 30 TAC Chapter 117 - Preamble

The tables show that emission reductions approaching the tpd rate required by the attainment demonstration necessitate further reductions from essentially all categories, including electric utility boilers and stationary gas turbines; ICI boilers and stationary gas turbines; duct burners used in turbine exhaust ducts; process heaters and furnaces; stationary IC engines; FCCUs (including catalyst regenerators and CO boilers and furnaces); pulping liquor recovery furnaces; lime kilns; lightweight aggregate kilns; heat treating furnaces; reheat furnaces; magnesium chloride fluidized bed dryers; incinerators (including enclosed control devices that combust or oxidize gases or vapors); and BIF units.

To develop the information in this table and analyze the reductions obtainable by potential NO_x emission rate specifications (in pound per million British thermal units (lb/MMBtu) heat input, gram per horsepower-hour (g/hp-hr), etc.), commission staff gathered the emission rate factors used to calculate June-August 1997 emissions for the major NO_x sources in HGA. In January 2000, commission staff sent out a rate data survey to major NO_x sources in HGA and made follow-up requests in an attempt to fill in missing rate data. In situations where the major NO_x sources did not or could not provide rate data, commission staff estimated the missing rate data from available data for similar equipment. Commission staff also conducted a quality assurance analysis of the 1997 emissions inventory in order to correctly classify equipment into the various categories shown in the table. The information was compiled in a spreadsheet, allowing reductions from a rate limit applied to an equipment category to be calculated either as a number of tons of NO_x per day reduced or as a percentage reduction from the category.

The commission staff then evaluated the emission reductions that would be achieved by applying various attainment demonstration emission rate limits to the equipment categories. Because some NO_x emission sources simply cannot be reasonably controlled (for example, flares), it is necessary that the larger emission categories, especially electric utility boilers, stationary gas turbines, engines, and ICI boilers, achieve more than a 90% reduction in order for the overall emission reductions from NO_x point sources to come as close as possible to the 90% target that modeling has shown is necessary for HGA to be able to demonstrate attainment of the ozone NAAQS. Through an iterative process, the commission staff developed emission specifications for the major NO_x point source categories which approach the maximum practicable emission reductions for these sources and, while technically challenging to meet, are a necessary and essential component of the HGA Attainment Demonstration SIP, adopted concurrently by the commission.

SECTION BY SECTION DISCUSSION

The primary purpose of the revisions to Chapter 117 and to the SIP is to establish new emission specifications for the ozone attainment demonstrations. However, another purpose of these revisions is to ensure that RACT requirements are applied to major NO_x sources in HGA, as required by 42 USC, §7511a(f). The current NO_x RACT limits in §117.105, concerning Emission Specifications for Reasonably Available Control Technology (RACT), and §117.205, concerning Emission Specifications for Reasonably Available Control Technology (RACT), apply to certain boilers, process heaters, stationary IC engines, and stationary gas turbines. The amendments establish emission specifications for boilers; process heaters and furnaces; stationary IC engines and stationary gas turbines; duct burners used in turbine exhaust ducts; FCCUs (including catalyst regenerators and associated CO boilers and furnaces); pulping liquor recovery furnaces; lime kilns; lightweight aggregate kilns; heat treating furnaces; reheat furnaces; magnesium chloride fluidized bed dryers; incinerators (including enclosed control devices that combust or oxidize gases or vapors); and BIF units which are currently exempt from the NO_x RACT limits in §117.105 and §117.205. While the emission specifications for attainment demonstration (ESADs) are more stringent than RACT, these emission specifications will nevertheless also fulfill the NO_x RACT requirements of 42 USC, §7511a(f), for major sources in HGA which are not subject to the previous NO_x RACT rules.

The amendments to §117.10, concerning Definitions, revise the definition of "auxiliary steam boiler" to clarify that an auxiliary steam boiler produces steam as a replacement for steam produced by another piece of equipment which is not operating due to planned or unplanned maintenance.

Although the term "incinerator" is defined in §101.1 to refer to units which burn wastes for the primary purpose of reducing volume and weight, this term historically has also been used to refer to enclosed control devices that combust or oxidize gases or vapors, particularly in Chapter 115. The ESADs for incinerators apply to both types of units. Therefore, the amendments to §117.10 add a definition of "incinerator" to clarify that for the purposes of Chapter 117, the term "incinerator" includes both enclosed control devices that combust or oxidize gases or vapors, and incinerators as defined in §101.1. The new definition is not a substantive change from how the commission intended the term to be used in Chapter 117, and its inclusion in the adopted rule will provide clarity. Subsequent definitions in §117.10 were renumbered to accommodate the addition of the new definition of "incinerator."

The amendments to §117.10 also revise the definition of "low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit" by changing the order of "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the title of this division. The amendments to §117.10 add a definition of "electric generating facility (EGF)" which is consistent with the corresponding definition in §117.330(12), concerning Definitions, and also add definitions of "heat treat furnace" and "reheat furnace" which are needed to clarify the units to which the new requirements apply. Subsequent definitions in §117.10 were renumbered to accommodate the new definitions.

In addition, the amendments to §117.10 revise the definitions of "boiler or steam generator," "electric power generating system," "industrial boiler or steam generator," "large DFW system," "process heater," "small DFW system," "unit," and "utility boiler or steam generator" by deleting the superfluous term "steam generator" since a steam generator is simply a boiler and is already addressed by this term in the Chapter 117 rules.

The amendments to §117.10 also revise the definition of "unit" to broaden its applicability. Currently, this definition includes boilers, process heaters, stationary gas turbines, and stationary IC engines. Because the emission reductions approaching the tpd emission rate required by the attainment demonstration necessitate further reductions from essentially all categories, the amendments broaden the applicability of the definition of unit to include any other stationary source of NO_x at a major source.

In addition, the amendments to §117.10 revise the renumbered §117.10(36) to define "predictive emissions monitoring system (PEMS)" rather than "predictive emission monitoring system (PEMS)" for consistency with the definition of "continuous emissions monitoring system (CEMS)" in the renumbered §117.10(9) and the usage of these terms in the rules. Finally, the amendments to §117.10 revise the definitions of "large DFW system" and "small DFW system" to improve the readability of these definitions.

The amendments to §117.101, concerning Applicability, delete the superfluous term "steam generator" since a steam generator is simply a boiler and is already addressed by this term in the Chapter 117 rules, and renumber the paragraphs accordingly. The amendments to §117.101 also revise a reference in the renumbered §117.101(3) from "gas turbines" to "stationary gas turbines" for consistency with the definition of this term in the renumbered §117.10(41), and update a reference to the definition of "electric power generating system" in the renumbered §117.10(12).

The amendments to §117.103, concerning Exemptions, revise §117.103(a) to specify the exemptions from the RACT requirements. The units which are exempt from RACT are those currently exempt under this subsection from the entire division. However, the revised language states that these units are exempt from the specific sections for which these units would otherwise be subject, rather than from the entire division. Although this would appear to narrow the scope of the exemptions, it is not expected to add any additional requirements because other sections in this division generally do not apply to these units (except as specified in §117.113, concerning Continuous Demonstration of Compliance). In addition, the amendments to §117.103 revise §117.103(a)(2) to delete the superfluous term "steam generator" since a steam generator is simply a boiler and is already addressed by this term in the Chapter 117 rules.

A new §117.103(b) specifies that stationary gas turbines and engines which are used solely to power other engines or gas turbines during start-ups are exempt from the attainment demonstration requirements of §117.106, concerning Emission Specifications for Attainment Demonstrations; §117.108, concerning System Cap; and §117.113, except as may be specified in §117.113(i). The attainment demonstration exemptions do not include the RACT exemptions for new units placed into service after November 15, 1992; utility boilers, and auxiliary steam boilers with an annual heat input less than or equal to $2.2(10^{11})$ Btu per year; and stationary gas turbines and engines which operate less than 850 hours per year, because emission reductions from essentially all categories are necessary to approach the tpd emission rate required by the attainment demonstration. Finally, subsections are given titles (catchlines) to identify the topics covered.

Because the attainment demonstration exemptions do not include the RACT exemptions for new units placed into service after November 15, 1992, the title of Subchapter B, concerning Combustion at Existing Major Sources, has been changed to Combustion at Major Sources.

The existing §117.103(b) includes an exemption from the oil-fired RACT emission limits during emergency conditions which necessitate oil firing. The amendments to §117.103 renumber this exemption as §117.103(c), break it into paragraphs to make the text more readable, and revise it to include exemption from the emission specifications of §117.106, concerning Emission Specifications for Attainment Demonstrations, and §117.108. This revision is adopted in order to address concerns regarding times of natural gas curtailments, which are typically a cold weather issue. Although the system cap is less likely to be exceeded under natural gas curtailment conditions because the 30-day average winter peak electric demand is not as great as the summer 30-day peak demand, extensive oil firing due to an emergency condition could cause exceedances of the cap. The broadening of the exemption in the renumbered §117.103(c) will address this concern.

The new §117.103(d) exempts from the requirements of Chapter 117 all combustion units which would meet the requirements of a standard permit currently being developed for electricity-generating combustion units rated at no more than ten megawatts (MW) in capacity and which emit no more than 0.015 lb NO_x/MMBtu heat input. The commission is adding this exemption to facilitate the installation of small (ten MW or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid. This exemption is intended to provide an incentive for installation and use of new clean energy-producing technology. The emission limit of the proposed standard permit is consistent with the adopted ESAD of 0.015 lb NO_x/MMBtu heat input.

The amendments to §117.105 revise §117.105(a)-(d) and (h) to delete the superfluous term "steam generator" since a steam generator is simply a boiler and is already addressed by this term in the Chapter 117 rules. The amendments to §117.105(h) also add equivalent alternate CO standards based on heat input to simplify compliance tracking for monitoring systems which are based on carbon dioxide as the diluent.

In addition, the amendments to §117.105 correct the title of §117.510 in §117.105(k)(2). Finally, the amendments to §117.105 add a new §117.105(l) which specifies that after the applicable attainment demonstration SIP compliance date(s), the RACT emission specifications will no longer apply to equipment for which §117.106, concerning Emission Specifications for Attainment Demonstrations, has established more stringent emission specifications. This will avoid any potential conflicts of RACT limits and the new more stringent attainment demonstration emission specifications. For purposes of §117.105(l), the RACT emission specifications of §117.105 remain in effect until the emissions allocation for a unit under the HGA mass emissions cap are equal or less than the allocation that would be calculated using the RACT emission specifications of §117.105.

The amendments to §117.106 specify new NO_x emission specifications for electric utility boilers located in HGA. The adopted specifications are essential components of and consistent with the HGA Attainment Demonstration SIP, adopted concurrently by the commission. The emission specifications and ozone attainment demonstration SIP are required by 42 USC, §7410 and §7511a, which require states to submit SIPs to the EPA which contain enforceable measures to achieve the NAAQS. The process by which the emission specifications were developed is described in the BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES section of this preamble.

The amendments to §117.106(a) and (b) abbreviate the term "pound per million Btu," correct a typographical error in "Beaumont/Port Arthur," and reorganize the syntax of these sentences for consistency with the new §117.106(c).

The NO_x emission specifications for electric utility boilers, auxiliary steam boilers, and stationary gas turbines located in HGA are being added as a new §117.106(c) and are based on a daily rate and 30-day average. The 24-hour emission limit in both NO_x RACT and these rules is designed to limit the amount of NO_x allowed in a 24-hour period, in order to control peak ozone, which forms on a daily cycle. The emission specifications of §117.106(c) also apply as specified in §117.108 and in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, concerning Mass Emissions Cap and Trade Program, adopted concurrently in this issue of the *Texas Register*.

The emission specifications of §117.106(c) for electric utility boilers, auxiliary steam boilers, and stationary gas turbines in HGA are part of a larger set of emission reduction measures for the HGA Attainment Demonstration SIP. The larger context of development of the NO_x emission specification for electric utility boilers, auxiliary steam boilers, and stationary gas turbines in HGA is discussed in the BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES section of this preamble. The emission specifications of 0.010 lb NO_x/MMBtu heat input for gas-fired boilers; 0.030 lb NO_x/MMBtu heat input for oil- or coal-fired, tangential-fired boilers; 0.030 lb NO_x/MMBtu heat input for oil- or coal-fired, wall-fired boilers; 0.010 lb NO_x/MMBtu heat input for auxiliary boilers with a maximum rated capacity equal to or greater than 100 MMBtu/hr; 0.015 lb NO_x/MMBtu heat input for auxiliary boilers with a maximum rated capacity equal to or greater than 40 MMBtu/hr but less than 100 MMBtu/hr; 0.036 lb NO_x per MMBtu heat input (or alternatively, 30 parts per million by volume (ppmv) NO_x, at 3.0% oxygen (O_2), dry basis) for auxiliary boilers with a maximum rated capacity less 40 MMBtu/hr; and alternatively, 0.060 lb/MMBtu for units with an annual capacity factor of 0.0383 or less will achieve a 93% emission reduction and generate an estimated 183.52 tpd NO_x reductions from HGA electric utility boiler emissions. The 93% NO_x reduction is expected to necessitate combustion controls and flue gas cleanup on many of the boilers at electric utilities in the HGA area.

A new §117.106(c)(4) provides low annual capacity factor units with an alternative to the emission specifications in §117.106(c)(1)-(3). The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation.

The emission specification of 0.015 lb NO_x/MMBtu heat input for stationary gas turbines (or 0.15 lb NO_x per MMBtu heat input for existing stationary gas turbines rated at less than 1.0 MW) will achieve a 91% emission reduction in conjunction with the emission specification of 0.015 lb NO_x per MMBtu heat input for stationary gas turbines and duct burners in §117.206(c)(10) and (11), respectively, concerning Emission Specifications for Attainment Demonstrations, and generate an estimated total of 140.92 tpd NO_x reductions from these units in HGA, based on the 1997 emissions inventory. The 91% NO_x reduction is expected to necessitate combustion controls and flue gas cleanup on many of the stationary gas turbines in the HGA area.

The existing §117.106(c) and (d) are being renumbered as §117.106(d) and (e). The amendments to the renumbered §117.106(d) make applicable in HGA the ammonia and CO emission limits in order to address pollutants which may increase as an incidental result of compliance with the NO_x emission specifications. The CO and ammonia limits are the limits which are applicable in Beaumont/Port Arthur (BPA) and Dallas/Fort Worth (DFW). This ammonia limit of ten ppmv is lower than the existing RACT limit of §117.105(j). The lower ammonia limit is supported by information from selective catalytic reduction (SCR) vendors and ammonia test data for gas-fired boilers using SCR, not available when the original NO_x RACT rules were adopted in 1993. The test data are reported in Table 2-5 of *Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers*, issued by the Northeast States for Coordinated Air Use Management (NESCAUM) and the Mid-Atlantic Regional Air Management Association (MARAMA) (June 1998) (will be referred to as NESCAUM). It is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The commission excluded these related pollutant limits from the attainment demonstration SIP in order to simplify the approval process for alternative emission specification under §107.121. This step will eliminate the need for case-specific SIP revisions by the EPA to complete the approval of an alternate CO or ammonia limit.

The amendments to the renumbered §117.106(d)(1) add equivalent alternate CO standards based on heat input to simplify compliance tracking for monitoring systems which are based on carbon dioxide as the diluent.

The amendments to the renumbered §117.106(e) specify that in HGA, the utility owner or operator may not use the trading option in §117.570. This is necessary to ensure that any trading that occurs is done under the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, adopted concurrently in this issue of the *Texas Register*. The owners and operators of the equipment addressed by these Chapter 117 revisions will be required to use the compliance flexibility provided by the Chapter 101 mass emissions cap and trade program, which will allow compliance to be established through the use of surplus reductions created from other sources. Units which meet the definition of EGF are required to use both the system cap specified in §117.108 and the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 to comply with the NO_x emission specifications of §117.106(c).

Section §117.106(e) also does not allow the use of §117.107 as an alternative for complying with the §117.106 emission specifications for attainment demonstrations. Section 117.107 emission averaging does not address the effects of activity level, and may not produce the intended reductions that would be achieved with direct compliance by all units or flexible compliance with an emission cap. Under §117.107, higher emissions will result if units selected for less control are subsequently operated more, or if units selected for more control are subsequently operated less. The §117.106 emission specifications will necessitate installation of flue gas cleanup emission controls on a number of units. As a result, these units are likely to have higher operating costs than units operating with only combustion controls, creating an economic incentive to operate the best-controlled units less and to produce greater emissions.

The amendments to §117.108 require the owner or operator of each EGF in HGA to comply with the daily and 30-day system cap emission limitations of the existing system cap. The amendments to §117.108 also revise §117.108(a)-(i) and (k) by replacing references to "utility boiler" with the term "EGF." In addition, the amendments to §117.108 revise §117.108(b) by updating the reference to the definition of "electric power generating system" in the renumbered §117.10(12).

The amendments to §117.108 also revise §117.108(e)(4) to replace a reference to testing in a non-existent rule with a reference to the maximum block one-hour emission rate as measured by the 30-day test. In addition, the amendments to §117.108 revise §117.108(f) by correcting the title in the reference to §117.119, concerning Notification, Recordkeeping, and Reporting Requirements.

Finally, the amendments to §117.108 revise §117.108(i), which specifies that an EGF which is permanently retired or decommissioned and rendered inoperable may be included in the source cap emission limit, to state that in HGA the permanent shutdown must have occurred after January 1, 2000. Because §117.108(c)(1) specifies 1997, 1998, and 1999 for calculating the emissions cap, it is necessary for the shutdown to occur after this period.

Currently, EGFs in DFW may comply with §117.106 through compliance with the daily and 30-day system cap available under §117.108. The commission solicited comments concerning the possibility of adding flexibility for these EGFs by allowing trading between different electric power generating systems in DFW in order to meet the system cap of §117.108. Any such flexibility would necessitate separate rulemaking to establish the mechanism for trading between different electric power generating systems in DFW. Comments received regarding this issue are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

The amendments to §117.111, concerning Initial Demonstration of Compliance, correct the sentence structure of §117.111(a) by changing "be tested" to "test the units." The amendments to §117.111 also correct the title of §117.510 in §117.111(a)(3), and revise §117.111(d)(3) by replacing the term "utility boilers" with "EGFs" for consistency with the corresponding changes to §117.108.

The amendments to §117.113, concerning Continuous Demonstration of Compliance, revise a reference in §117.113(f)(2)(A)(ii) from "United States Environmental Protection Agency" to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions.

The amendments to §117.113 also revise the catchline in §117.113(g) to clarify that these subsections apply to the NO_x RACT emission specifications of §117.105, and revise references in §117.113(g)(1) and (2) from "gas turbine" to "stationary gas turbine" for consistency with the definition of this term in §117.10(41).

In addition, the amendments to §117.113 add a new §117.113(h)(2) which specifies the totalizing fuel flow meter requirements for units at major NO_x sources in HGA which are subject to §117.106. All units which are listed in §117.101 will be subject to the totalizing fuel flow meter requirements because knowledge of the fuel usage is critical in determining the emission allocations for the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, adopted concurrently in this issue of the *Texas Register*. The existing §117.113(h)(1)-(3) is being renumbered as §117.113(h)(1)(A)-(C) to accommodate the new §117.113(h)(2).

The amendments to §117.113 also revise §117.113(i) to reflect the addition of the new §117.103(b). This revision will ensure that stationary gas turbines and engines which were required to install run time meters under the existing RACT requirements will continue to utilize those existing run time meters.

In addition, the amendments to §117.113 also revise §117.113(k) (being renumbered as §117.113(k)(1)) to specify that this subparagraph only applies to units in BPA or DFW, or to units in HGA which are subject to the NO_x RACT emission specifications of §117.105. A new §117.113(k)(2) specifies that for units in HGA which are subject to the ESADs of §117.106(c), the methods required in §117.113 and §117.114 shall be used in conjunction with the requirements of Chapter 101, Subchapter H, Division 3 to determine compliance. The new §117.113(k)(2) further specifies that for enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission specifications.

Finally, the amendments to the catchlines in §117.113(l) clarify that this subsection applies to the NO_x RACT emission specifications of §117.105.

The new §117.114 applies to units in HGA which are subject to the ESADs of §117.106(c) and specifies monitoring and testing requirements. The new §117.114(a) requires monitoring for NO_x, CO, and fuel flow as specified in §117.113(a)-(f) and (g). The new §117.114(b) requires testing of each unit which is subject to the emission specifications of §117.106(c). The testing requirements are consistent with the testing previously required of these units for NO_x RACT under §117.111.

Regarding emission allowances for the Chapter 101 mass emissions cap and trade program, §117.114(c) specifies that the NO_x testing and monitoring data specified in §117.114(a) and (b), together with the level of activity, as defined in §101.350, concerning Definitions, are used to establish the emission factor for the mass emissions cap and trade program. For units without CEMS or PEMS, retesting is required after any modifications which could increase the NO_x emission rate, but is optional after any modifications which could decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation (FGR), and fuel-lean and conventional (fuel-rich) reburn. The NO_x emission rate determined by the retesting establishes a new emission factor which must be used instead of the previously determined emission factor for the Chapter 101 mass emissions cap and trade program.

The amendments to §117.116, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, revise "units" to "utility boilers" in §117.216(a)(2) because the requirements of this section only apply to utility boilers. In addition, the amendments to §117.116 correct a title which is referenced in §117.116(c).

The amendments to §117.119 revise a reference in §117.119(a) from "Unites States Environmental Protection Agency" (which should have been "United States Environmental Protection

Agency") to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions; and correct the reference in §117.119(a) to §101.11 to reflect the recent title change of this section from "Exemptions from Rules and Regulations" to "Demonstrations." (See the July 14, 2000 issue of the *Texas Register* (25 TexReg 6727).) The amendments to §117.110 also revise a reference in §117.119(d)(1)(A) from "gas turbines" to "stationary gas turbines" for consistency with the definition of this term in §117.10(41).

The amendments to §117.121, concerning Alternative Case Specific Specifications, update a reference to the existing §117.106(c) which is being renumbered as §117.106(d) and revise a reference from "United States Environmental Protection Agency" to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions. The amendments to §117.121(a) also add a reference to §117.106(d).

The amendments to §117.138, concerning System Cap, revise §117.138(b) to update a reference to the renumbered §117.10(12).

The amendments to §117.201, concerning Applicability, generalize the applicability by deleting the references to size cutoffs and adding the following to the list of units which are subject to this division: FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents); pulping liquor recovery furnaces; lime kilns; lightweight aggregate kilns; heat treating furnaces; reheat furnaces; magnesium chloride fluidized bed dryers; incinerators (including enclosed control devices that combust or oxidize gases or vapors); BIF units which were regulated as existing facilities by the EPA at 40 Code of Federal Regulations (CFR) Part 266, Subpart H (as was in effect on June 9, 1993); and duct burners used in turbine exhaust ducts. It is necessary to generalize the applicability since the HGA Attainment Demonstration SIP rules include units which are presently excluded from §117.201. These changes do not broaden the scope of the existing rules in BPA or HGA due to corresponding exemptions already in, or being added to, §117.203, concerning Exemptions, and §117.205(h) which are described later in this preamble. Finally, the amendments to §117.201 revise §117.201(1) by changing the order of "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the title of this division. Units used to produce steam for the purpose of generating electricity, but which are not owned or operated by a municipality or Public Utility Commission of Texas (PUCT) regulated utility, are included in the applicability of §117.201, rather than §117.101.

The amendments to §117.203 move the existing exemptions into a new subsection (a) and add a new exemption for heat treating furnaces and reheat furnaces as new §117.203(a)(3), with an expiration of this exemption in HGA for units rated at 20 MMBtu/hr or greater after the appropriate compliance date(s) for §117.206(c) specified in §117.520, concerning Compliance Schedule for Commercial, Institutional, and Industrial Combustion Sources in Ozone Nonattainment Areas. The expiration of this exemption in HGA for certain units is necessary for consistency with the amendments to §117.206(c)(14), which establishes emission specifications for these units in HGA.

In addition, the exemption in the existing §117.203(3) for electric utility power generating boilers was deleted. Although this change would appear to narrow the scope of the exemptions, it is not expected to add any additional requirements to these units in BPA and DFW because other sections in this division do not apply to these units. The requirements for units in HGA which are not subject to §117.106 will parallel the requirements of §117.206.

Further, the amendments to the renumbered §117.203(a)(4) and (5) specify that the exemptions for incinerators (including enclosed control devices that combust or oxidize gases or vapors), pulping liquor recovery furnaces, dryers, kilns, and ovens in HGA no longer apply after the appropriate compliance date(s) for §117.206 specified in §117.520. The amendments to the renumbered §117.203(a)(4) and (5) are necessary for consistency with §117.206(c)(12)-(16), which establish emission specifications for certain units in these categories in HGA.

The amendments to §117.203 also add a new §117.203(a)(9) which exempts boilers and process heaters with a maximum rated capacity of 2.0 MMBtu/hr or less. This exemption level is being adopted because units with a maximum rated capacity of 2.0 MMBtu/hr or less are already regulated under Subchapter D, Division 1, concerning Water Heaters, Small Boilers, and Process Heaters.

In addition, the amendments to §117.203 add a new §117.203(a)(10) which exempts diesel-fired stationary IC engines. It should be noted that §117.203(a)(6)(A) exempts stationary gas turbines and engines which are used in research and testing, or used for purposes of performance verification and testing, or used solely to power other engines or gas turbines during start-ups, or operated exclusively for firefighting and/or flood control, or used in response to and during the existence of any officially declared disaster or state of emergency, or used directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals, or used as chemical processing gas turbines. However, in the future, the commission may pursue emission reductions from these currently-exempt engines in HGA if additional reductions are determined to be necessary to reach attainment with the ozone NAAQS.

The amendments to §117.203 also add a new §117.203(b) which specifies that the exemptions in §117.203(a)(1), (2), (6)(B), (7), and (8)(A) no longer apply in HGA after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520. The expiration of these exemptions in HGA for certain units is necessary for consistency with §117.206(c), which establishes emission specifications for these units in HGA.

The new §117.203(c) exempts from the requirements of Chapter 117 all combustion units which would meet the requirements of a standard permit currently being developed for electricity-generating combustion units rated at no more than ten MW in capacity and which emit no more than 0.015 lb NO_x/MMBtu heat input. The commission is adding this exemption to facilitate the installation of small (ten MW or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid. This exemption is intended to provide an incentive for installation and use of new clean energy-producing technology. The emission limit of the proposed standard permit is consistent with the adopted ESAD of 0.015 lb NO_x/MMBtu heat input.

The amendments to §117.205 revise §117.205(b)(6) to include an equation for calculating an emission limitation for each rolling 30-day period for cases when gas fired boilers or process heaters at times also fire gaseous fuel which contain more than 50% hydrogen by volume. The equation uses a time weighted average to incorporate the two emission limits, from combusting two types of gaseous fuels, into one emission limitation for each rolling 30-day average. This amendment is based on a rule interpretation (Code Number R7-205.001) made by the agency's Air Rule Interpretation Team.

The amendments to §117.205 also revise §117.205(b)(7) by changing references from "continuous emission monitors" to "continuous emissions monitoring system" and from "predictive emission monitors" to "predictive emissions monitoring system" for consistency with the definitions of these terms in §117.10(9) and (36), respectively.

In addition, the amendments to §117.205 revise §117.205(c) to allow stationary gas turbines equipped with CEMS or PEMS for CO to meet the CO limit on a rolling 24-hour average, rather than on a one-hour average. This revision is consistent with the corresponding CO limit for boilers and process heaters in §117.205(f).

The amendments to §117.205 also revise §117.205(h)(1) by changing the order of "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the title of this division.

Additionally, the amendments to §117.205 revise the language for FCCUs and duct burners in §117.205(h)(4) and (5) for consistency with the corresponding language in §117.201(4) and (6). The amendments to §117.205(h) also add new paragraphs (8)-(10) for new units placed into service after November 15, 1992; stationary gas turbines and engines which are demonstrated to operate less than 850 hours per year (based on a rolling 12-month average); and stationary IC engines with a horsepower (hp) rating of less than 150 hp and 300 hp in HGA and BPA, respectively.

Finally, the amendments to §117.205 add a new §117.205(i) which specifies that after the applicable attainment demonstration SIP compliance date, the RACT emission specifications will no longer apply to equipment for which §117.206 has established a more stringent emission specification. This will avoid any potential conflicts of RACT limits and the new more stringent ESADs. For purposes of §117.205(i), the RACT emission specifications of §117.205 remain in effect until the emissions allocation for a unit under the HGA mass emissions cap are equal or less than the allocation that would be calculated using the RACT emission specifications of §117.205.

The amendments to §117.206(a) and (b) revise references to subsections (d) and (e), which should have been (e) and (f), to subsections (f) and (g) to accommodate the new §117.206(c) described in the following paragraph. In addition, the amendments to §117.206(b)(2) abbreviate the terms "horsepower" and "carbon monoxide."

The amendments to §117.206 add a new §117.206(c) which establishes NO_x emission specifications for boilers, process heaters, stationary IC engines, stationary gas turbines, FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents), BIF units, duct burners used in turbine exhaust ducts, pulping liquor recovery furnaces, lime kilns, lightweight aggregate kilns, heat treating furnaces, reheat furnaces, magnesium chloride fluidized bed dryers, and incinerators (including enclosed control devices that combust or oxidize gases or vapors) at major sources of NO_x in HGA. For units in HGA, the emission specifications in the new §117.206(c) will be used in the new Chapter 101, Subchapter H, Division 3, to establish emission allocations and shall be the lower of any applicable permit limit or the emission specifications described in the following paragraphs.

The amendments are essential components of and consistent with the HGA Attainment Demonstration SIP, adopted concurrently by the commission. The adopted emission specifications and ozone attainment demonstration SIP are required by 42 USC, §7410 and §7511a, which require states to submit SIPs to the EPA which contain enforceable measures to achieve the NAAQS. The amendments to §117.206 also update cross-references and renumber subsequent subsections to accommodate the new emission specifications within the section. The process by which the emission specifications were developed is described in the BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES and the *TECHNICAL FEASIBILITY* portion of the ANALYSIS OF TESTIMONY of this preamble.

The emission specifications in §117.206(c)(1) of 0.010 lb NO_x per MMBtu heat input for gas-fired boilers with a maximum rated capacity equal to or greater than 100 MMBtu/hr; 0.015 lb NO_x per MMBtu heat input for gas-fired boilers with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr; and 0.036 lb NO_x per MMBtu heat input (or alternatively, 30 ppmv NO_x, at 3.0% O_2, dry basis) for gas-fired boilers with a maximum rated capacity less 40 MMBtu/hr will achieve a 92% NO_x emission reduction from ICI boilers and generate an estimated 57.26 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification in §117.206(c)(2) of 13 ppmv NO_x (at 0.0% O_2, dry basis) for FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents) will achieve a 90% NO_x emission reduction and generate an estimated 13.44 tpd NO_x reductions in HGA, based on the 1997 emissions inventory. Alternative emission specifications for FCCUs include a 90% NO_x reduction of the exhaust concentration used to calculate the June-August 1997 daily NO_x emissions; or for units which did not use CEMS or PEMS to determine the June-August 1997 exhaust concentration, a 90% NO_x reduction of the exhaust concentration in a third quarter 2001 baseline established by installation and certification of a NO_x CEMS or PEMS no later than June 30, 2001.

The emission specification in §117.206(c)(3) is 0.015 lb NO_x per MMBtu heat input for BIF units with a maximum rated capacity equal to or greater than 100 MMBtu/hr, and either 0.030 lb NO_x per MMBtu or an 80% reduction from the emission factor used to calculate the June-August 1997 daily NO_x emissions for BIF units with a maximum rated capacity less than 100 MMBtu/hr. This will achieve an 80% NO_x emission reduction and generate an estimated 9.78 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification in §117.206(c)(4) of 0.057 lb NO_x per MMBtu heat input for coke-fired boilers will achieve a 90% NO_x emission reduction and generate an estimated 10.44 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification in §117.206(c)(5) of 0.046 lb NO_x per MMBtu heat input for wood fuel-fired boilers will achieve a 78% NO_x emission reduction and generate an estimated 0.79 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification in §117.206(c)(6) of 0.089 lb NO_x per MMBtu heat input for rice hull-fired boilers will achieve a 90% NO_x emission reduction and generate an estimated 0.46 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification in §117.206(c)(7) of 2.0 lb NO_x per 1,000 gallons of oil burned for oil-fired boilers will achieve a 90%

NO_x emission reduction and generate an estimated 0.13 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specifications in §117.206(c)(8) of 0.010 lb NO_x per MMBtu heat input for process heaters with a maximum rated capacity equal to or greater than 100 MMBtu/hr; 0.015 lb NO_x per MMBtu heat input for process heaters with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr; and 0.036 lb NO_x per MMBtu heat input (or alternatively, 30 ppmv NO_x, at 3.0% O_2, dry basis) for process heaters with a maximum rated capacity less 40 MMBtu/hr will achieve an 88% NO_x emission reduction from process heaters and generate an estimated 96.56 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specifications for stationary reciprocating IC engines in §117.206(c)(9) are: 0.17 g NO_x/hp-hr for gas-fired rich-burn engines; 0.50 g NO_x/hp-hr for gas-fired lean-burn engines; 5.83 g NO_x/hp-hr for existing dual-fuel, stationary reciprocating IC engines; and 0.50 g NO_x/hp-hr for dual-fuel, stationary reciprocating IC engines initially placed into service after December 31, 2000. These emission specifications will achieve an 88% NO_x emission reduction and generate an estimated 75.63 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specifications for stationary gas turbines in §117.206(c)(10) and duct burners used in turbine exhaust ducts in §117.206(c)(11) of 0.015 lb NO_x per MMBtu heat input (or 0.15 lb NO_x per MMBtu heat input for existing stationary gas turbines rated at less than 1.0 MW) will achieve a 91% NO_x emission reduction in conjunction with the emission specification of 0.015 lb NO_x per MMBtu heat input for stationary gas turbines in §117.106(c)(3) and generate an estimated total of 140.92 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification for pulping liquor recovery furnaces in §117.206(c)(12) of 0.050 lb NO_x per MMBtu heat input (or alternatively, 1.08 lb NO_x per air-dried ton of pulp (ADTP)) will achieve a 64% NO_x emission reduction and generate an estimated 1.09 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specifications for kilns in §117.206(c)(13) of 0.66 lb NO_x per ton of calcium oxide (CaO) for lime kilns and 0.76 lb NO_x per ton of product for lightweight aggregate kilns will achieve a 39% NO_x emission reduction from the kiln category and generate an estimated 0.30 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specifications for heat treating furnaces and reheat furnaces in §117.206(c)(14) of 0.087 lb NO_x per MMBtu heat input for heat treating furnaces and 0.062 lb NO_x per MMBtu heat input for reheat furnaces will achieve a 35% NO_x emission reduction from the steel furnace category and generate an estimated 0.39 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification for magnesium chloride fluidized bed dryers in §117.206(c)(15) of a 90% reduction from the emission factor used to calculate the June-August 1997 daily NO_x emissions will achieve a 41% NO_x emission reduction from the dryer category and generate an estimated 0.95 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

The emission specification for incinerators (including enclosed control devices that combust or oxidize gases or vapors) in §117.206(c)(16) of an 80% reduction from the emission factor used to calculate the June-August 1997 daily NO_x emissions; or alternatively, 0.030 lb NO_x per MMBtu heat input, will achieve a 54% NO_x emission reduction and generate an estimated 3.22 tpd NO_x reductions in HGA, based on the 1997 emissions inventory.

A new §117.206(c)(17) provides low annual capacity factor units with an alternative to the emission specifications in §117.206(c)(1)-(16). The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation.

The NO_x emission limit averaging times for BPA and DFW in the renumbered §117.206(d)(1) are consistent with the averaging times for NO_x RACT compliance in §117.205(b)(7). Units with NO_x emission monitors are capable of tracking emissions over time, and are allowed to demonstrate compliance on a 30-day average in BPA and DFW under this subsection. The amendments to §117.206 also revise §117.206(d)(1)(A) by changing references from "continuous emission monitors" to "continuous emissions monitoring system" and from "predictive emission monitors" to "predictive emissions monitoring system" for consistency with the definitions of these terms in §117.10(9) and (36), respectively. For HGA, a new §117.206(d)(2) specifies that the averaging time for the ESADs shall be as specified in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3, except that EGFs shall also comply with the daily and 30-day system cap emission limitations of §117.210, concerning System Cap.

The emission limits of the renumbered §117.206(e) address pollutants which may increase as an incidental result of compliance with the NO_x limits. The CO limit is consistent with the existing CO limit of §117.205(f) for RACT because nothing in these rules necessitates changing the existing limit. In rulemaking adopted on April 19, 2000, the commission intended to change the proposed ammonia limit of five ppm to ten ppm in the renumbered §117.205(e)(2) but inadvertently did not change the rule language. (See the May 5, 2000 issue of the *Texas Register* (25 TexReg 4146).) The amendment to the renumbered §117.206(e)(2) makes this correction. The ammonia limit of ten ppm is lower than the existing limit of §117.205(g) and is supported by information from SCR vendors and ammonia test data for gas-fired boilers using SCR, not available when the original NO_x RACT rules were adopted in 1993. The test data are reported in Table 2-5 of NESCAUM. It is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The commission is not including these related pollutant limits in the attainment demonstration SIP, in order to simplify the approval process for alternative emission specification under §107.221. This step will eliminate the need for case-specific SIP revisions to complete the approval of an alternate CO or ammonia limit.

The amendments to §117.106(d) also clarify the adopted rule language by changing "utility boiler" to "unit." This change will not impact any additional units in BPA and DFW because §117.106(a) and (b) only apply to utility boilers. The adopted rule language of §117.206(e) changed "boiler or process heater" to "unit." This change will not impact any additional units in BPA because §117.206(a) only applies to boilers and process heaters in BPA. In DFW, §117.206(b) likewise already applies to boilers and process heaters, and therefore this change will not impact any boilers or process heaters in DFW. Although §117.206(b) also applies to gas-fired and gas/liquid-fired lean-burn stationary reciprocating IC engines in DFW, none of the three engines in DFW which are subject to §117.206(b) would have to comply with the ammonia limit because they can meet the emission limits using low emission combustion (LEC) modifications rather than post-combustion controls.

Regarding the CO limits, the amendments to §117.206(e) specifically exclude stationary IC engines in BPA and DFW because these engines are already subject to a CO limit in §117.205(e) and §117.206(b)(2), respectively. The amendments to §117.206(e)(1) specify a CO limit for IC engines in HGA that is consistent with these existing CO standards. In addition, the amendments to §117.206(e) specifically exclude BIF units and incinerators in HGA which are already subject to CO limits in other rules (for example, 40 CFR 266.102(e)(2)(ii)(A) and 40 CFR 266.104(b)). Finally, the amendments exclude boilers and process heaters operating in "hot-standby" mode and lightweight aggregate kilns from correcting CO to 3.0% O_2, dry basis, because these units typically will operate with high excess O_2 which will drive the CO level, when corrected to 3.0% O_2, to a high level.

With the exception of the availability of alternative CO and ammonia limits through §117.221, the amendments to the renumbered §117.206(f) specify that an owner or operator in HGA may not use the alternative plant-wide emission specifications in §117.207, the alternative case-specific specifications of §117.221, the source cap in §117.223, or the trading option in §117.570, except that EGFs shall also comply with the daily and 30-day system cap emission limitations of §117.210 of this title. This is necessary to ensure that any trading that occurs is done under the Chapter 101 mass emissions cap and trade program being adopted concurrently in this issue of the *Texas Register*. The owners and operators of the equipment addressed by these Chapter 117 amendments will be required to use the compliance flexibility provided by the new Chapter 101 mass emissions cap and trade program, which will allow compliance to be established through the use of surplus reductions created from other sources.

In addition, the amendments to §117.206 revise the renumbered §117.206(g) to make the exemptions of §117.206(g)(1) and (2) unavailable in HGA for consistency with the applicability of §117.206(c). The amendments to the renumbered §117.206(g)(1) also change the order of "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the title of this division.

Finally, the amendments to §117.206 add a new subsection (h) which prohibits the owner or operator of units which utilize liquid or gaseous streams containing chemical-bound nitrogen as a source of fuel or combustion air from circumventing the emission reduction requirements by directing these streams to flares or other units which are not subject to an ESAD in §117.206(c), unless the unit which receives the chemical-bound nitrogen stream is opted into the Chapter 101 mass emissions cap and trade program, and NO_x emissions from this opt-in unit are determined using a CEMS or PEMS which meets the requirements of §117.213(e) or (f) or through stack testing which meets the requirements of §117.211(e), concerning Initial Demonstration of Compliance.

The amendments to §117.207, concerning Alternative Plant-wide Emission Specifications, update cross-references to renumbered rules. The amendments to §117.207 also revise §117.207(b)(1) by changing references from "continuous emission monitors" to "continuous emissions monitoring system" and from "predictive emission monitors" to "predictive emissions monitoring system" for consistency with the definitions of these terms in §117.10(9) and (36), respectively.

In addition, the amendments to §117.207(f) change references to §117.206(e), which should have been §117.206(f), to §117.206(g) to account for the subsection renumbering in §117.206.The amendments to §117.207 also revise references in §117.207(f)(1) from "gas turbines" and "engines" to "stationary gas turbines" and "stationary internal combustion engines" for consistency with the definition of these terms in §117.10(41) and (42), respectively.

Finally, the amendments to §117.207(f)(4) delete the superfluous term "steam generator" since a steam generator is simply a boiler and is already addressed by this term in the Chapter 117 rules, and revise a reference from "United States Environmental Protection Agency" to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions.

The amendments to §117.208, concerning Operating Requirements, correct the format of references to §§117.205-117.207 and 117.223 for consistency with *Texas Register* formatting requirements, revise a reference in §117.208(d)(4) from "gas turbines" to "stationary gas turbines" for consistency with the definition of this term in §117.10(41), and revise §117.208(d) to exclude sources subject to §117.206(c).

The new §117.210 establishes a system cap for units which generate electricity, but which will be subject to §117.206 rather than §117.106. The new §117.210, would create a flexible method of complying with the NO_x emission specifications in §117.206 for units which meet the definition of EGF. The system cap requirements in §117.210 exclude cogeneration units whose electric output entirely serves one or several dedicated industrial customers, except when the industrial customers are not operating. These sources are base load sources and are not operated at higher levels on hot summer days to meet electric demand and would not contribute additional emissions during these periods. Therefore, these sources are more similar to electric generating units located at an industrial site which do not generate electricity for compensation. Because these industrial electric generators do not provide electricity for peaking, they were never included in the system cap for the reasons described in the previous paragraph.

The new §117.210 is patterned on the existing source cap compliance option in §117.108 for electric utilities. The system cap sets limits on total pounds of NO_x allowed to be emitted by EGFs which will not be subject to §117.106. 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's compliance measures may include installing less extensive emission controls on a piece of equipment and choosing to operate it less, or upgrading its efficiency to require less fuel firing.

The amendments to §117.211 revise §117.211(e)(5) by revising a reference from "United States Environmental Protection Agency" to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions.

The amendments to §117.213, concerning Continuous Demonstration of Compliance, add a new §117.213(a)(1)(B) which specifies the totalizing fuel flow meter requirements for units at major NO_x sources in HGA which are subject to §117.206. With the exception of wood-fired boilers and pulping liquor recovery furnaces for which fuel flow monitoring is impractical, all units which are listed in §117.201 will be subject to the totalizing fuel flow meter requirements because knowledge of the fuel usage is critical in determining the emission allocations for the new Chapter 101 mass emissions cap and trade program. The existing §117.213(a)(1)(A)-(D) is being renumbered as §117.213(a)(1)(A)(i)-(iv) to accommodate the new §117.213(a)(1)(B).

The amendments to §117.213 also revise the renumbered §117.213(a)(1)(A)(ii) (currently §117.213(a)(1)(B)) to reflect the renumbering of §117.203(6) and (8) as §117.203(a)(6) and (8) and the addition of the new §117.205(h)(9)-(10), and revise §117.213(b)(2)(A) and §117.213(c)(2)(A) to reflect the addition of the new §117.205(h)(8)-(10). The existing requirement in §117.213(b) for O_2 monitors on certain boilers and process heaters will continue to apply to these sources in HGA after the emission specifications of §117.206(c) supersede those of §117.205.

In addition, the amendments to §117.213 also add new §117.213(c)(1)(G)-(I) to specify that the requirement to install a CEMS or PEMS NO_x monitor applies to the following units in HGA: lime kilns, lightweight aggregate kilns, and units with a rated heat input greater than or equal to 100 MMBtu/hr which are subject to §117.206(c). The existing requirement in §117.213(c) for NO_x monitors on certain boilers, process heaters, stationary gas turbines, and units which use a chemical reagent for reduction of NO_x will continue to apply to these sources in HGA after the emission specifications of §117.206(c) supersede those of §117.205. Similarly, the existing requirement in §117.213(d)-(f) for CO monitoring, CEMS, and PEMS will continue to apply to these sources in HGA after the emission specifications of §117.206(c) supersede those of §117.205.

The amendments to §117.213 also revise §117.213(c)(1)(F) and (2)(A), and (k) (being renumbered as §117.213(k)(1)) to specify that these rules only apply to units in BPA or DFW, or to units in HGA which are subject to the NO_x RACT emission specifications of §117.205. A new §117.213(k)(2) specifies that for units in HGA which are subject to the ESADs of §117.206(c), the methods required in §117.213 and §117.214 shall be used in conjunction with the requirements of Chapter 101, Subchapter H, Division 3 to determine compliance. The new §117.213(k)(2) further specifies that for enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission specifications.

In addition, the amendments to §117.213 revise §117.213(g) by dividing it into two paragraphs, one for engines not using NO_x CEMS or PEMS, and one for engines using NO_x CEMS or PEMS. A new subparagraph (1)(C) specifies that gas-fired emergency generators are not required to conduct periodic testing under the renumbered §117.213(g)(1)(B).

The amendments to §117.213 also revise a reference in §117.213(h) from "gas turbines" to "stationary gas turbines" for consistency with the definition of this term in §117.10(41), and revise §117.213(i) to reflect the renumbering of §117.203(6)(B) as §117.203(a)(6)(B).

Finally, the amendments to the catchlines in §117.213(l) and (m) clarify that these subsections apply to the NO_x RACT emission specifications of §117.205.

The new §117.214 applies to units in HGA which are subject to the ESADs of §117.206(c) and specifies monitoring and testing requirements. The new §117.214(a) requires monitoring for NO_x, CO, and fuel flow as specified in §117.213(a) and (c)-(f). The new §117.214(b)(1) requires testing of each unit which is subject to the emission specifications of §117.106(c). The testing requirements are consistent with the testing previously required of these units for NO_x RACT under §117.211. A new §117.214(b)(2) adds a quarterly engine testing requirement, based upon the existing §117.208(d)(7). Because quarterly emission testing for engines that run no more than ten hours per month could result in these engines operating when they otherwise would be idle, thereby increasing emissions, the commission has included language which states that quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours. This exemption does not diminish the requirement to test emissions after the installation of controls, major repair work, and any time the owner or operator believes emissions may have changed.

Regarding emission allowances for the new Chapter 101 mass emissions cap and trade program, §117.214(c) specifies that the NO_x testing and monitoring data specified in §117.214(a) and (b), together with the level of activity, as defined in §101.350, are used to establish the emission factor for the mass emissions cap and trade program. For units without CEMS or PEMS, retesting is required after any modifications which could increase the NO_x emission rate, but is optional after any modifications which could decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), FGR, and fuel-lean and conventional (fuel-rich) reburn. The NO_x emission rate determined by the retesting establishes a new emission factor which must be used instead of the previously determined emission factor for the new Chapter 101 mass emissions cap and trade program.

The amendments to §117.216, concerning Final Control Plan Procedures for Attainment Demonstration Emission Specifications, revise §117.216(a)(1) to reference the system cap of 117.210 and the Chapter 101 mass emissions cap and trade program being adopted concurrently in this issue of the *Texas Register*. This revision is necessary because the owners and operators of the equipment addressed by these Chapter 117 revisions will be required to use the compliance flexibility provided by the new Chapter 101 mass emissions cap and trade program, which will allow compliance to be established through the use of surplus reductions created from other sources.

The amendments to §117.219, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.219(a) by correcting the reference to §101.11 to reflect the recent title change of this section from "Exemptions from Rules and Regulations" to "Demonstrations." (See the July 14, 2000 issue of the *Texas Register* (25 TexReg 6727)).

The amendments to §117.219 also replace the term "performance evaluation" with "relative accuracy test audit" in §117.219(b)(2) to more accurately describe the CEMS or PEMS performance evaluation; and replace the term "executive director" with "appropriate regional office" in §117.219(c) to more precisely specify where at the agency the test results are to be sent.

The amendments to §117.219 reduce the semiannual report requirements of §117.219(d) for sources in the HGA mass emissions cap and trade program that are not subject to (or no longer subject to) §117.205 to a monitoring system report.

In addition, the amendments to §117.219 revise references in §117.219(d)(1)(A) and the renumbered §117.219(f)(4) from "gas turbine" to "stationary gas turbine" for consistency with the definition of this term in §117.10(41).

The amendments to §117.219 also revise a reference in the renumbered §117.219(f)(3) from "internal combustion engine" to "stationary internal combustion engine" for consistency with the definition of this term in §117.10(42), and revise a reference in the renumbered §117.219(f)(4) from "gas turbine" to "stationary gas turbine" for consistency with the definition of this term in §117.10(41).

In addition, the amendments to §117.219(f) renumber paragraphs (1)-(8) as (2)-(9) to accommodate the new §117.219(f)(1), and add a new §117.219(f)(1) in order to specify that records of annual fuel usage shall be kept for each unit subject to the totalizing fuel flow meter requirements of §117.213(a). The amendments to the renumbered §117.219(f)(2) add a new subparagraph (C) for units subject to the mass emissions cap and trade program since compliance with the ESADs in HGA will be on an annual basis. However, EGFs subject to the system cap of §117.210 additionally will be required to keep daily records under §117.219(f)(2)(B). Finally, the amendments to the renumbered §117.219(f)(3)(A)(i) correct a typographical error in a reference to §117.208(d)(7).

The amendments to §117.221, concerning Alternative Case Specific Specifications, revise §117.221(a) to reflect the renumbering of §117.206(d) as §117.206(e), and revise a reference in §117.211(b) from "United States Environmental Protection Agency" to "EPA" because this abbreviation is defined in Chapter 3, concerning Definitions. The amendments to §117.221(a) also add a reference to §117.206(e).

The new requirements of §117.471, concerning Applicability; §117.473, concerning Exemptions; §117.475, concerning Emission Specifications; §117.478, concerning Operating Requirements; and §117.479, concerning Monitoring, Recordkeeping, and Reporting Requirements, apply to stationary reciprocating IC engines, boilers, and process heaters located in HGA at stationary sources of NO_x which are not major sources of NO_x. Therefore, a new Division 2, concerning Boilers, Process Heaters, and Stationary Engines at Minor Sources, is being added to Subchapter D, concerning Small Combustion Sources.

The adopted emission specifications are essential components of and consistent with the HGA Attainment Demonstration SIP, adopted concurrently by the commission. The emission specifications and ozone attainment demonstration SIP are required by 42 USC, §7410 and §7511a, which require states to submit SIPs to the EPA which contain enforceable measures to achieve the NAAQS. The process by which the emission specifications were developed is described in the BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES section of this preamble.

The new §117.471 specifies that the new Division 2, concerning Boilers, Process Heaters, and Stationary Engines at Minor Sources, which is being added to Subchapter D, concerning Small Combustion Sources, applies to stationary reciprocating IC engines, boilers, and process heaters located in HGA at a stationary source of NO_x which is not a major source of NO_x.

The new §117.473 exempts boilers and process heaters with a maximum rated capacity of 2.0 MMBtu/hr or less. This exemption is included because units with a maximum rated capacity of 2.0 MMBtu/hr or less are already regulated under Subchapter D, Division 1, concerning Water Heaters, Small Boilers, and Process Heaters.

In addition, the following engines are exempt in the new §117.473: engines used in research and testing; engines used for purposes of performance verification and testing; engines used solely to power other engines or gas turbines during start-ups; engines operated exclusively for firefighting and/or flood control; engines used in response to and during the existence of any officially declared disaster or state of emergency; and engines used directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals. This exemption is consistent with the exemption in the renumbered §117.203(3) which is available for stationary sources of NO_x which are major sources of NO_x. The new §117.473 also exempts stationary reciprocating IC engines with a hp rating of 50 hp or less and emergency generators that do not operate more than 100 hours per year.

In addition, the new §117.473 establishes an exemption for certain boilers and process heaters located at any stationary source of NO_x which is not subject to Chapter 101, Subchapter H, Division 3. The boilers and process heaters qualify for this exemption if the maximum rated capacity is greater than 2.0 MMBtu/hr and less than 5.0 MMBtu/hr and the annual heat input is less than or equal to 1.8 (10^9) Btu per calendar year; or if the maximum rated capacity is equal to or greater than 5.0 MMBtu/hr and the annual heat input is less than or equal to 9.0 (10^9) Btu per calendar year. However, the totalizing fuel flow requirements of §117.479(a), (d), and (g)(1) will apply to these exempted units in order to document that the annual heat input conditions of the exemption are met.

The new §117.473(c) exempts from the requirements of Chapter 117 all combustion units which would meet the requirements of a standard permit currently being developed for electricity-generating combustion units rated at no more than ten MW in capacity and which emit no more than 0.015 lb NO_x/MMBtu heat input. The commission is adding this exemption to facilitate the installation of small (ten MW or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid. This exemption is intended to provide an incentive for installation and use of new clean energy-producing technology. The emission limit of the proposed standard permit is consistent with the adopted ESAD of 0.015 lb NO_x/MMBtu heat input.

The new §117.475 establishes an emission specification of 0.036 lb NO_x per MMBtu heat input (or alternatively, 30 ppmv NO_x, at 3.0% O_2, dry basis) for boilers and process heaters in HGA at non-major stationary sources of NO_x. The new §117.475 also establishes an emission specification of 0.50 g NO_x/hp-hr for gas-fired stationary reciprocating IC engines in HGA at non-major stationary sources of NO_x. A new §117.475(c)(3) provides low annual capacity factor units with an alternative emission specification. The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation.

The new §117.478 specifies techniques to be used to minimize NO_x emissions. Section 117.478(b)(1) requires boilers to be operated with O_2, CO, or fuel trim. Such systems can pay for themselves with fuel savings while reducing NO_x due to low excess air operation and reduced firing. Fuel trim has been demonstrated as an effective control technique for natural gas fired boilers operating with FGR to achieve compliance with a 30 ppmv NO_x limit.

The new §117.478(b)(2) requires operation of boilers and process heaters equipped with forced FGR such that the proportional design rate of FGR is maintained over the operating range.

The new §117.478(b)(3) requires operation of any post combustion controls such that the injection rate of the reducing agent (i.e., ammonia or urea) is maintained to limit NO_x concentrations to no more than the NO_x concentrations achieved at maximum rated capacity.

The new §117.478(b)(4) requires engines controlled with nonselective catalytic reduction (NSCR) to be operated with an air-fuel ratio (AFR) controller which operates on exhaust O_2 or CO.

The new §117.478(b)(5) is based upon the existing §117.208(d)(7) and requires engines to be checked for proper operation measuring and recording NO_x and CO emissions at least quarterly and as soon as practicable within two weeks after each occurrence of engine maintenance which may reasonably be expected to increase emissions, O_2 sensor replacement, or catalyst cleaning or catalyst replacement. The new §117.478(b)(5) allows the use of stain tube indicators specifically designed to measure NO_x concentrations, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. The new §117.478(b)(5) also allows the use of portable NO_x analyzers. Because quarterly emission testing for engines that run no more than ten hours per month could result in these engines operating when they otherwise would be idle, thereby increasing emissions, the commission has included language which states that quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours. This exemption does not diminish the requirement to test emissions after the installation of controls, major repair work, and any time the owner or operator believes emissions may have changed.

The new §117.479 specifies the monitoring, recordkeeping, and reporting requirements for boilers, process heaters, and engines which are subject to the emission specifications of §117.475.

The new §117.479(a) requires installation of totalizing fuel flow meters because knowledge of the fuel usage is critical in determining the NO_x emission rate as well as the emission allocations for the new Chapter 101 mass emissions cap and trade program.

The new §117.479(b) does not require O_2 monitors, but instead specifies that if an owner or operator installs an O_2 monitor, then the criteria in §117.213(e) is the appropriate guidance for the location and calibration of the monitor.

The new §117.479(c) does not require NO_x monitors, but instead specifies that if an owner or operator installs a NO_x monitor, then it must meet the CEMS or PEMS requirements of §117.213(e) or (f).

The new §117.479(d) specifies that monitors must be installed on the schedule specified in §117.534.

The new §117.479(e) specifies the testing requirements for boilers, process heaters, and engines which are subject to the emission specifications of §117.475. These requirements are based upon the existing requirements of §117.211. Section 117.479 also specifies that for units without CEMS or PEMS, retesting is required after any modifications which could increase the NO_x emission rate, but is optional after any modifications which could decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), FGR, and fuel-lean and conventional (fuel-rich) reburn. The NO_x emission rate determined by the retesting establishes a new emission factor which must be used instead of the previously determined emission factor for the new Chapter 101 mass emissions cap and trade program.

The new §117.479(f) specifies that the NO_x testing and monitoring data specified in §117.479(a)-(e), together with the level of activity, as defined in §101.350, are used to establish the emission factor for the new Chapter 101 mass emissions cap and trade program.

The new §117.479(g) specifies the records to be used to demonstrate compliance with the emission specifications of §117.475.

The new §117.479(h) specifies the recordkeeping requirements for engines which are necessary to document exemption status.

The amendments to §117.510, concerning Compliance Schedule for Utility Electric Generation, revise §117.510(c) to create separate paragraphs in this subsection addressing compliance schedules for the NO_x RACT rules and the emission specifications for attainment demonstrations. For investor-owned electric utilities, the commission is adopting a staged six-year implementation schedule for compliance with the new HGA emission specifications. First, 46% of the total reductions required to comply with the emission specifications are required by March 31, 2003. The next 46% of the reductions are required by March 31, 2004. The final reductions are required by March 31, 2007. The commission believes that this compliance schedule is appropriate for investor-owned electric utilities since emission reduction projects are already underway to implement the majority of the emission reductions necessary to meet the ESADs for investor-owned electric utilities. A combination of combustion controls and flue gas cleanup controls will be necessary on many units.

The amendments to §117.510(b)(2) modify the compliance schedule for utility boilers in DFW by allowing exclusion of boilers which are to be retired and decommissioned before May 1, 2005 from the calculation of the emission reductions to be made by May 1, 2003. This two-year compliance schedule extension will avoid the costs associated with installation of controls which would be used for a relatively short period of time, yet still achieve the necessary emission reductions from the soon-to-be-retired utility boilers before the critical 2005 ozone season, thereby contributing to DFW's attainment of the ozone NAAQS. To qualify for this compliance date extension, a boiler must be designated by the PUCT to be necessary to operate for reliability of the electric system, and the owner must provide the executive director an enforceable written commitment by May 1, 2003 to retire and permanently decommission the boiler by May 1, 2005.

In addition, the amendments to §117.510 add the missing word "in" to §117.510(a)(2)(E)(iii) and (F) and the renumbered §117.510(b)(2)(A)(v)(III) and (vi). The amendments to §117.510 also make a variety of minor punctuation corrections throughout the section. Finally, the amendments to §117.510 revise §117.510(a)(2)(A)(i) and the renumbered §117.510(b)(2)(A)(i)(I) by replacing a reference to the effective date of these rules with the actual effective date, May 11, 2000.

The amendments to §117.520, concerning Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas, revise §117.520(c) to create separate paragraphs in this subsection addressing compliance schedules for the NO_x RACT rules and the emission specifications for attainment demonstrations. The commission is adopting a staged six-year implementation schedule for compliance with the new HGA emission specifications. First, 44% of the total reductions required to comply with the emission specifications are required by March 31, 2004. The next 45% of the reductions are required by March 31, 2005. The final reductions are required by March 31, 2007. A combination of combustion controls and flue gas cleanup controls will be necessary on many units.

In addition, the amendments to §117.520 add the missing word "in" to §117.520(a)(3)(B)(v) and (E)(iii) and the renumbered §117.510(b)(2)(A)(v)(III) and (vi). The amendments to §117.520 also revise §117.520(a), (b), and (c) by changing the order of "commercial, institutional, or industrial" to "industrial, commercial, or institutional" for consistency with the title of this division. Finally, the amendments to §117.520 revise §117.520(a)(3)(A)(i) by replacing a reference to the effective date of this rule with the actual effective date, May 11, 2000.

The new §117.534 specifies the compliance schedule for boilers, process heaters, and stationary engines at minor sources in HGA. For sources subject to the new Chapter 101 mass emissions cap and trade program, the commission is adopting a staged six-year implementation schedule for compliance with the new HGA emission specifications. First, 44% of the total reductions required to comply with the emission specifications are required by March 31, 2004. The next 45% of the reductions are required by March 31, 2005. The final reductions are required by March 31, 2007. For sources not subject to the new Chapter 101 mass emissions cap and trade program, the emission reductions are required by March 31, 2005.

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 and demonstrate attainment in the HGA ozone nonattainment area. 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.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMIT PROGRAM

Since 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 DETERMINATION

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, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.

The amendments do not meet any of the four applicability criteria for requiring a regulatory analysis of "major environmental rule" as defined in the Texas Government Code. Section 2001.0225 applies only to a major environmental rule the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

The amendments to Chapter 117 will require emission reductions from electric utility boilers and stationary gas turbines; ICI boilers and stationary gas turbines; duct burners used in turbine exhaust ducts; process heaters and furnaces; stationary IC engines; FCCUs (including catalyst regenerators and CO boilers and furnaces); pulping liquor recovery furnaces; lime kilns; lightweight aggregate kilns; heat treating furnaces; reheat furnaces; magnesium chloride fluidized bed dryers; incinerators (including enclosed control devices that combust or oxidize gases or vapors); and BIF units in the HGA ozone nonattainment area. The rules are intended to protect the environment and reduce risks to human health and safety from environmental exposure and may have adverse effects on certain utilities, petrochemical plants, refineries, and other industrial, commercial, or institutional groups, and each group could be considered a sector of the economy. While the amendments are intended to protect the environment, the commission believes they may adversely affect in a material way sources in the HGA ozone nonattainment area with a potential to emit NO_x in amounts greater than or equal to ten tons per year (tpy), as well as boilers, heaters, and stationary engines at sources with a potential to emit NO_x in amounts less than ten tpy. These sources comprise sectors of the economy (including petroleum refineries, petrochemical plants, and electric generating plants) in a sector of the state. This is based on the analysis provided in the rule proposal preamble which was published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275), including the discussion in the Public Benefit and Costs section.

The amendments implement requirements of the FCAA. Under 42 USC, §7410, states are required 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 42 USC, §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, such as 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 42 USC, §7410. Thus, while specific measures are not generally required, the emission reductions are required. States are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule.

The requirement to provide a fiscal analysis of proposed regulations in the Texas Government Code was amended by Senate Bill (SB) 633 during the 75th Legislative Session. The intent of SB 633 was to require agencies to conduct a regulatory impact analysis (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 earlier in this preamble, 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 proposes and 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 required by federal law.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The adopted rules, which reduce ambient NO_x and ozone in HGA, will be submitted to the EPA as one of several measures of the required new attainment demonstrations. These rules will also satisfy requirements for implementation of NO_x RACT at major sources in HGA which are not subject to the previous NO_x RACT rules. The FCAA, 42 USC, §7511a(f), requires any moderate, serious, severe, or extreme ozone nonattainment area to implement NO_x RACT, unless a demonstration is made that NO_x reductions would not contribute to or would not be necessary for attainment of the ozone standard. By policy, the EPA requires photochemical grid modeling to demonstrate whether the 42 USC, §7511a(f), NO_x measures would contribute to ozone attainment. The commission has performed photochemical grid modeling which predicts that NO_x emission reductions, such as those required by these rules, will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone. The 42 USC, §7511a(f), exemption from NO_x measures for HGA expired on December 31, 1997. The expiration of the exemption under 42 USC, §7511a(f), was based on the finding that NO_x reductions in HGA are necessary for attainment of the ozone standard. Therefore, the adopted amendments are necessary components of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

The TNRCC has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. It is presumed that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485. 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied)*; and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

As discussed earlier in this preamble, this rulemaking implements requirements of the FCAA. There is no contract or delegation agreement that covers the topic that is the subject of this rulemaking. In addition, the rulemaking complies with the requirements of the Texas Health and Safety Code, Texas Clean Air Act (TCAA) §§382.011, 382.012, 382.014, 382.016, 382.017, 382.021 and 382.051(d). Therefore, the adopted rules do not exceed a standard set by federal law, exceed an express requirement of state law, exceed a requirement of a delegation agreement, nor are adopted solely under the general powers of the agency. Comments received during the comment period regarding the draft RIA are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

TAKINGS IMPACT ASSESSMENT (TIA)

The commission evaluated this rulemaking action and performed an analysis of whether the adopted rules are subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. The specific purposes of these rules are to achieve reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone and to implement NO_x RACT required by 42 USC, §7511a(f) for certain source categories. Texas Government Code, §2007.003(b)(4), provides that Chapter 2007 does not apply to these adopted rules since they are reasonably taken to fulfill an obligation mandated by federal law. The emission limitations and control requirements within this rulemaking were developed in order to meet the NAAQS for ozone set by the EPA under 42 USC, §7409. States are primarily responsible for ensuring attainment and maintenance of NAAQS once the EPA has established them. Under 42 USC, §7410, 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, one purpose of this rulemaking is to meet the air quality standards established under federal law as NAAQS. Attainment of the ozone standard will eventually require substantial NO_x reductions as well as VOC reductions. Any NO_x reductions resulting from the current rulemaking are no greater than what scientific research indicates is necessary to achieve the desired ozone levels. However, this rulemaking is only one step among many necessary for attaining the ozone standard. Another purpose is to satisfy the NO_x RACT requirements at major sources in HGA which are not subject to the previous NO_x RACT rules. The FCAA, 42 USC, §7511a(f), requires any moderate, serious, severe, or extreme ozone nonattainment area to implement NO_x RACT, unless a demonstration is made that NO_x reductions would not contribute to or would not be necessary for attainment of the ozone standard.

In addition, Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rule revisions 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 significantly advance the health and safety purpose. This action is taken in response to the HGA area exceeding the federal ambient air quality standard for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ozone levels in the HGA nonattainment area. Consequently, these rules meet the exemption in §2007.003(b)(13).

The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP, which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking therefore meets the requirements of Texas Government Code, §2007.003(b)(4) and (13). For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis. Comments received during the comment period regarding the TIA are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

COASTAL MANAGEMENT PROGRAM CONSISTENCY REVIEW

The commission has determined that this rulemaking action relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et seq.), and the commission's rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with the Texas Coastal Management Program. As required by 30 TAC §281.45(a)(3) and 31 TAC §505.11(b)(2), relating to actions and rules subject to the CMP, commission rules governing air pollutant emissions must be consistent with the applicable goals and policies of the CMP. The commission has reviewed this rulemaking action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council, and has determined that this rulemaking action is consistent with the applicable CMP goals and policies. The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(1)). No new sources of air contaminants will be authorized and ozone levels will be reduced as a result of these rules. The CMP policy applicable to this rulemaking action is the policy that commission rules comply with regulations in 40 CFR, to protect and enhance air quality in the coastal area (31 TAC §501.14(q)). This rulemaking action complies with 40 CFR Part 50, National Primary and Secondary Ambient Air Quality Standards, and 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal Of Implementation Plans. Therefore, in compliance with 31 TAC §505.22(e), this rulemaking action is consistent with CMP goals and policies. No comments were received during the comment period regarding the CMP consistency review.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000.

Two hundred fifty-one commenters submitted testimony on the proposal. Pasadena Paper Company LP, Pasadena Pulp Company LP, and Donohue Industries Incorporated submitted joint comments and will be referred to as Pasadena/Donohue. The League of Women Voters of Texas (LWV-TX); Manufacturers of Emission Controls Association (MECA); Public Citizen; Sustainable Economic and Environmental Development (SEED); and 19 individuals supported the proposed revisions, while Hispanic Community of Texas Citizens for a Sound Economy (TCSE-HC); JB Services; RMT, Inc. on behalf of Montgomery County (Montgomery Co.); Safety-Kleen (Deer Park), Incorporated (Safety-Kleen); and four individuals opposed the proposed revisions. Baker Botts L.L.P. (Baker Botts); BASF Corporation (BASF); Baytown Chamber of Commerce (Baytown COC); BP; Business Coalition for Clean Air (BCCA); Calpine Central, L.P. (Calpine); Chevron Phillips Chemical Company LP (Chevron); City of Baytown (Baytown); City of Houston Department of Health and Human Services (HDHHS); City of Missouri City (Missouri City); City of Spring Valley (Spring Valley); Clean Air Partnership (CAP); Clear Lake Area Chamber of Commerce (Clear Lake COC); Corpus Christi Air Quality Committee;

Corpus Christi City Council Member Arnold Gonzales; Crown Central Petroleum Corporation (Crown); Diamond-Koch; Dow Chemical Company (Dow); DuPont; Dynegy, Incorporated (Dynegy); East Harris County Manufacturers Association (EHCMA); Engine Manufacturers Association (EMA); Enron; Entergy Services, Incorporated (Entergy); Enterprise Products Operating L.P. (Enterprise); EPA; Equistar Chemicals LP (Equistar); ExxonMobil Corporation (ExxonMobil); Fuel Tech, Incorporated (Fuel Tech); Galveston County Judge Jim Yarbrough; Galveston-Houston Association for Smog Prevention (GHASP); Gas Processors Association (GPA); Goodyear Rubber and Tire Company (Goodyear); Grandparents of East Harris County (GEHC); Harris County Judge Robert Eckels; Houston Metropolitan Planning Organization's Transportation Policy Council (Houston MPO); Kaneka Texas Corporation (KTC); Kinder Morgan, Incorporated (Kinder Morgan); Lyondell Chemical Company (Lyondell); Lyondell-Citgo Refining LP (Lyondell-Citgo); Mothers for Clean Air; National Aeronautics and Space Administration (NASA); Pasadena/Donohue; Pavilion Technologies, Incorporated (Pavilion); PECO Energy Company (PECO); Phillips 66 Company (Phillips 66); Regional Air Quality Consensus Group (RAQCG); Reliant Energy, Incorporated (REI); Rhodia, Incorporated (Rhodia); RMT, Incorporated (RMT); Sierra Club--Galveston Regional Group (Sierra-Galveston); Sierra Club--Houston Regional Group (Sierra-Houston); Solar Turbines Incorporated (Solar Turbines); Solutia; State Representative Jaime Capelo; State Senator Carlos Truan; Tennessee Gas Pipeline Company (TGP); Texas Association of Business and Chambers of Commerce (TABCC); Texas Chemical Council (TCC); Texas City Mayor Carlos Garza; Texas Eastern Transmission Corporation (Texas Eastern); Texas Gulf Coast Asthma Coalition (TGCAC); Texas Industry Project (TIP); Texas Medical Center Central Heating and Cooling Services Cooperative Association (TECO); Texas Oil and Gas Association (TxOGA); Texas Pulp and Paper Industry Environmental Council (TPIEC); Trunkline Gas Company (TGC); TXI Operations, L.P. (TXI); TXU Business Services (TXU); Union Carbide Corporation (Union Carbide); Valero Refining Company-Texas (Valero); Wyman-Gordon Forgings (Wyman-Gordon); and 148 individuals supported the proposed revisions but suggested changes or clarifications.

BP supported the comments submitted by TIP and TCC, except as noted in the ANALYSIS OF TESTIMONY section. Chevron supported the comments submitted by BCCA and TCC. Corpus Christi Air Quality Committee, Corpus Christi City Council Member Arnold Gonzales, State Representative Jaime Capelo, and two individuals supported the comments submitted by State Senator Carlos Truan. Crown supported the comments submitted by TxOGA. Dow and Lyondell supported the comments submitted by BCCA, TCC, and TIP. DuPont supported the comments submitted by TCC. Dynegy and Enron supported the comments submitted by BCCA. Entergy and TPIEC supported the comments submitted by TIP. Equistar supported the comments submitted by BCCA, EHCMA, TCC, and TIP. ExxonMobil supported the comments submitted by BCCA, EHCMA, TCC, TIP, and TxOGA. Goodyear and REI supported the comments submitted by BCCA and TIP. Harris County Judge Robert Eckels supported the comments submitted by CAP, Houston MPO, and RAQCG. Lyondell-Citgo supported the comments submitted by BCCA and TxOGA. Pasadena/Donohue supported the comments submitted by TPIEC. Phillips 66 supported the comments submitted by BCCA, TCC, TIP, and TxOGA. Valero supported the comments submitted by BCCA, TIP, and TxOGA.

ANALYSIS OF TESTIMONY

GENERAL COMMENTS

LWV-TX; MECA; Public Citizen; SEED; TGCAC; and 19 individuals supported the proposed revisions to Chapter 117.

The commission appreciates the support.

TCSE-HC; JB Services; Safety-Kleen; and four individuals opposed the proposed revisions to Chapter 117. Montgomery Co. and one individual opposed implementation of the proposed Chapter 117 revisions in Montgomery County, four individuals opposed implementation of the proposed Chapter 117 revisions in Chambers County, and six individuals opposed implementation of the proposed Chapter 117 revisions in Liberty County.

As noted earlier in this preamble, the amendments are necessary to implement requirements of the FCAA. Under 42 USC, §7410, states are required to adopt a SIP which provides for "implementation, maintenance, and enforcement" of the primary NAAQS in each air quality control region of the state. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The rules, which reduce ambient NO_x and ozone in HGA, will be submitted after adoption to the EPA as one of several measures of the required new attainment demonstrations. These rules will also satisfy the NO_x RACT requirements at major sources in HGA which are not subject to the previous NO_x RACT rules. The FCAA, 42 USC, §7511a(f), requires any moderate, serious, severe, or extreme ozone nonattainment area to implement NO_x RACT, unless a demonstration is made that NO_x reductions would not contribute to or would not be necessary for attainment of the ozone standard. Further, the adopted rules are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. The adopted rules satisfy these federal requirements and are necessary to ensure that the current SIP revision in support of the HGA ozone attainment demonstration will be federally approvable.

Furthermore, the FCAA Amendments of 1990 provided new requirements for areas that had not attained the NAAQS for ozone, carbon monoxide, particulate matter, sulfur dioxide, nitrogen dioxide, and lead, and new requirements for SIPs in general. The EPA was authorized to designate areas failing to meet the NAAQS for ozone as nonattainment and to classify them according to severity. FCAA, §107(d)(4)(A)(iv) mandated that areas designated as serious, severe, or extreme for ozone that were within a metropolitan statistical area (MSA) or CMSA must have boundaries that include the entire MSA or CMSA. This requirement is supported by the legislative history for the FCAA Amendments in Senate Report No. 101-228, page 3399, which states that "Because ozone is not a local phenomenon but is formed and transported over hundreds of miles and several days, localized control strategies will not be effective in reducing ozone levels. The bill, thus, expands the size of areas that are defined as ozone nonattainment areas to assure that controls are implemented in an area wide enough to address the problem." The FCAA Amendments did provide the ability to exclude portions of the entire MSA or CMSA prior to designation, if the state conducted a study that the EPA agreed proved that the geographic portion did not contribute significantly to violation of the NAAQS.

Redesignation has not occurred for any portion of the HGA nonattainment area, and is not currently being considered. For existing areas currently included within a nonattainment area, the specific area must be redesignated as attainment to be removed from a nonattainment area. FCAA, §107(d)(3) provides that the EPA may not redesignate a nonattainment area, or a portion thereof, to attainment unless several criteria are met, which include: a determination that the area has attained the NAAQS; there is a fully approved SIP for the area; there is a determination that the improvement in air quality is due to permanent and enforceable reductions in emissions; there is an approved maintenance plan for the area; and the state has met all requirements for the area under FCAA, §110 and Part D.

However, even if a specific area within the HGA nonattainment area was redesignated by the EPA as attainment for ozone, reductions associated from all adopted ozone control strategies would still be necessary because of the requirements of FCAA, §107(d)(3) and §175A, which require maintenance plans for all redesignated areas. The maintenance plan must include the measures specified in §107(d)(3) and any additional measures that are necessary to ensure that the area continues to be in attainment with the NAAQS for ten years after the redesignation. Eight years after the redesignation, the state is required to submit an additional revision to the SIP for maintaining the NAAQS for ten years after the end of the first ten-year period.

Additionally, reductions associated with the ozone control strategies that will be implemented outside the HGA nonattainment area will benefit the HGA nonattainment area. This is due to the regional nature of air pollution, the contribution from mobile sources, and the economies of scale and associated market advantages related to distribution networks for some strategies.

At the time the 1990 FCAA Amendments were enacted, the focus on controlling ozone pollution was centered on local controls. However, for many years an ever 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, due to high ozone and ozone precursor levels entering from the boundaries of their respective modeling domains, commonly called transport. Recent science indicates that regional approaches may provide improved control of ozone air pollution.

The commission has conducted air quality modeling and upper air monitoring that found regional air pollution should be considered when studying air quality in Texas' ozone nonattainment areas. This work is supported by research conducted by OTAG, the most comprehensive attempt ever undertaken to understand and quantify the transport of ozone. Both the commission and the OTAG study point to the need to take a regional approach to controlling air pollutants. In fact, the transport of ozone-forming chemicals has been conclusively demonstrated both in modeling and ambient air analyses over distances far greater than that from southern counties in the HGA nonattainment area to downtown Houston.

One individual commented that the rules go beyond anything necessary to protect the environment, the basis and analysis in the rules is flawed, and the rules are being set up to embarrass Texas and the Governor, and the individual hopes that state legislators and Congress would investigate these plans. The individual also commented that the TNRCC and the EPA should be downsized because less government is better than more government.

The commission does not agree that the rules are too broad or that the basis or analysis of the rules is flawed. As noted earlier in this preamble, the amendments are necessary to implement requirements of the FCAA. Under 42 USC, §7410, states are required to adopt a SIP which provides for "implementation, maintenance, and enforcement" of the primary NAAQS in each air quality control region of the state. In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and 42 USC, §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The rules, which reduce ambient NO_x and ozone in HGA, will be submitted after adoption to the EPA as one of several measures of the required new attainment demonstrations. These rules will also satisfy the NO_x RACT requirements at major sources in HGA which are not subject to the previous NO_x RACT rules. The FCAA, 42 USC, §7511a(f), requires any moderate, serious, severe, or extreme ozone nonattainment area to implement NO_x RACT, unless a demonstration is made that NO_x reductions would not contribute to or would not be necessary for attainment of the ozone standard. The adopted rules satisfy these federal requirements and are necessary to ensure that the current SIP revision in support of the HGA ozone attainment demonstration will be federally approvable. Further, the adopted rules are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. The commission's intent is not to embarrass Texas and the Governor but instead to comply with the timelines provided in 1990 FCAA amendments and subsequent EPA guidance for submitting rules to demonstrate ozone attainment in HGA. Accordingly, Texas has committed to adopting the majority of the necessary rules for the HGA attainment demonstration by December 31, 2000.

GEHC and fifty-one individuals commented that more should be done to reduce emissions from NO_x point sources, particularly EGFs, refineries, chemical plants, and sources along the ship channel.

It is true that emissions from refineries or other significant point sources like those along the ship channel or Texas City may account for an important part of HGA emissions. It is also true that all parts of HGA make significant contributions to air pollution and that reductions from major point sources alone will not be enough to meet federal air quality standards. To meet the federal ozone standard, it will be necessary for additional sources of pollution to be reduced. The commission believes that the adopted rules include an appropriate level of control for NO_x point sources, taking into consideration the technical feasibility described later in this preamble.

An individual commented that Houston does not have the geographic restrictions that Los Angeles has (i.e., mountain ranges preventing pollution from being blown away), that Houston still has the worst pollution in the United States, and that stricter point source rules are needed.

The commission agrees with the commenter that Houston and Los Angeles have different geographical features that may either contribute to ozone formation or inhibit ozone formation and dispersion. For example, while HGA may not have nearby mountains that impede air flow, it does have a common summer weather pattern peculiar to this part of the Gulf Coast. The same air moves in from the Gulf during the day and out to the Gulf during the night, without really going anywhere (analogous to a bathtub sloshing effect). The geography of the Gulf Coast contributes to this weather pattern and makes it more difficult to attain the ozone standard. The commission continues to study the unique geographic and meteorologic features of HGA to determine their role in ozone formation and dispersion. Additionally, the adopted rules for HGA include an overall 85% NO_x reduction from point sources, as well as reductions in on-road mobile sources, non-road mobiles sources, and area sources. It should be noted that the adopted stringent controls on NO_x point sources, plus the other control measures (including gap measures), are necessary for the commission's modeling to show modeled attainment in HGA. Therefore, controls on all segments of the inventory are needed.

Five individuals suggested tax incentives for installation of pollution control equipment.

Such tax incentives are already available. In 1993, Texas voters approved the Proposition 2 constitutional amendment, which provides property tax exemptions on property used for pollution control purposes. The intent of this amendment is to ensure capital investments undertaken to comply with environmental mandates do not result in an increase in property taxes. The rules governing this property were adopted under 30 TAC Chapter 17, and under these rules, the TNRCC is responsible for determining whether property is used for pollution control purposes, and whether a facility may apply for a property tax exemption to its local appraisal district.

Sierra-Galveston, GEHC, GHASP, and thirty-five individuals expressed concern about enforcement of the proposed rules. Seventeen of these individuals recommended high penalties for noncompliance. One individual commented that the enforcement of the rules in Liberty County would be difficult because they would be hard pressed to justify allocating resources and manpower to enforce these types of rules when there are more serious problems in that area.

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. The commission will work with local officials to ensure enforcement of the SIP and SIP rules. The commission has existing relationships with pollution control authorities in the City of Houston, Harris County, and Galveston County for enforcement of other commission rules. The commission will continue enforcement relationships with these entities and develop relationships with other local officials as needed to create effective enforcement mechanisms for the SIP and SIP rules.

Missouri City questioned whether it would be required to enforce the proposed Chapter 117 revisions.

The rules are enforced by staff in the TNRCC's regional offices, as well as local air pollution control programs. Local governments have the same power and are subject to the same restrictions as the commission under TCAA, §382.015, Power to Enter Property, to inspect the air and to enter public or private property in its territorial jurisdiction to determine if the level of air contaminants in an area in its territorial jurisdiction meet levels set by the commission. Local governments are not required to enforce commission rules but may sign cooperative agreements with the commission to enforce the rules under TCAA, §382.115, Cooperative Agreements. Local programs can also enforce commission rules without signing a cooperative agreement. The authority of local governments to enforce air pollution requirements is specified in detail in TCAA, §§382.111-382.115, and local governments can institute civil actions in the same manner as the commission pursuant to Texas Water Code, §7.351.

An individual suggested that the commission provide technical experts to industry in order to assist industry in implementing projects to meet the proposed emission specifications. The individual also suggested that the public be informed about these projects.

The TNRCC's technical experts in the Air Permits Division are available to assist in answering questions concerning the permitting of such projects. Staff in the TNRCC's Pollution Prevention and Industry Assistance Section are also available to provide suggestions for reducing pollution. Ultimately, however, the regulated community is responsible for implementation of its own projects. Regarding the commenter's suggestion that the public be informed about projects to meet the emission specifications, the commission notes that the list of the pending permit projects is available on the commission's website at: http://www.tnrcc.state.tx.us/updated/air/nsr/nsrmap.shtml. In addition, the new source review (NSR) permitting program is subject to the public notice requirements found in 30 TAC Chapter 39.

Two individuals stated that all requirements should apply statewide, while GHASP stated that all requirements should apply in east Texas.

The commission appreciates the commenters' support for statewide applicability of the adopted rules. The commission notes, however, that it is not obligated to adopt all rules statewide in order to satisfy its commitments under the SIP, nor is the commission required to do so under the FCAA. Three of the adopted measures contain emission reduction strategies that have been adopted with state-wide applicability: California large-spark ignition engines; emissions banking and trading program (that portion of the adopted rules which relates to the trading of emission reduction credits and discrete emission reduction credits); and cleaner diesel fuel (that portion of the adopted rules which relates to on-highway fuel).

In evaluating whether to implement all of the rules statewide, the commission took into account many concerns, including the need for the marketplace to be able to respond to regulation, the possible impacts on transport and distribution systems, the possibility of increased costs and financial burdens on regulated entities, and regional needs and issues associated with state-wide mandates. The commission analyzed where emission reduction measures are most needed and where emission reduction measures will be most effective in order to demonstrate attainment.

An individual suggested that all emission reductions should be completely voluntary.

The EPA provides for the inclusion of voluntary programs or measures as part of the attainment demonstration, but limits the amount of emission reduction credit that may be claimed from such measures, due to the fact that the programs are not enforceable mechanisms. In accordance with EPA policy, the commission has included some voluntary programs as part of the HGA SIP. The Houston Galveston Area Council (HGAC) is the entity responsible for the development and implementation of these programs, which are detailed in the HGA SIP as the Voluntary Mobile Source Emissions Reduction Program (VMEP). If these rules became voluntary, they could not be counted as an enforceable measure obtaining emission reductions for the demonstration of attainment. As stated elsewhere in this preamble, the emission reductions associated with these rules are necessary for the attainment of the NAAQS in the HGA area.

Four individuals stated that Ellis County cement kilns should meet the same standards as EGFs in DFW.

No changes were proposed to the Chapter 117 NO_x emission specifications for cement kilns. Therefore, the commission cannot revise the Chapter 117 cement kiln rules in this rulemaking because the newly affected parties in Ellis County would not have had adequate notice and opportunity to comment. However, there have been recent developments regarding post-combustion controls on cement kilns in Europe and Asia. Because these developments indicate that post-combustion controls are technically feasible on dry-process cement kilns, the commission may revisit the Chapter 117 NO_x emission specifications for cement kilns if additional emission reductions are determined to be necessary to reach attainment with the ozone NAAQS in the future. The commission has made no change in response to the comment.

Two individuals stated that the commission should lobby to exempt Texas EGFs from the requirements of the National Fuel Use Act of 1978, which mandated a move toward the use of coal rather than natural gas. GHASP and an individual stated that the commission should require conversion of coal-fired EGFs to natural gas.

The provision of the Fuel Use Act that prohibited the use of natural gas was repealed in 1985. A diversity of fuel sources is in the interest of the consumer to limit the effect of price increases. There is also a substantial investment in the coal infrastructure, and consumer prices would be affected by the suggested conversion of coal-fired EGFs to natural gas. Also, insufficient natural gas reserves exist in this country to make a major shift away from coal as a baseload utility fuel. According to the PUCT, coal supplies more than 50% of the utility generation on a national basis. It would be unrealistic to assume that coal-fired EGFs could shut down or convert all coal-firing to natural gas.

GHASP stated that air pollution control technology should be required on all coal-fired EGFs. An individual stated that best available control technology (BACT) should be required on all coal-fired EGFs in HGA and all of east Texas.

The adopted Chapter 117 rules include emission specifications for coal-fired EGFs based on REI's design specifications. The operation of these units in HGA will set a new standard as BACT for coal upon successful in-use demonstration and will result in an estimated 92% reduction in NO_x emissions from the 1997 emissions inventory. In addition, the commission adopted emission specifications on April 19, 2000 for coal-fired EGFs in east and central Texas which will result in a 50% reduction in NO_x emissions. (See the May 5, 2000 issue of the *Texas Register* (25 TexReg 4101).) The commission may pursue additional emission reductions from EGFs in east and central Texas if those reductions are determined to be necessary to reach attainment with the ozone NAAQS in the future. The commission has made no change in response to the comment.

Galveston County Judge Jim Yarbrough, Harris County Judge Robert Eckels, Houston MPO, RAQCG, Texas City Mayor Carlos Garza, and an individual stated that the Chapter 117 requirements should provide for maximum flexibility, consistent with current and emerging technologies and retrofit feasibility and necessary NO_x emission reductions.

The commission has included flexibility to the extent possible while still achieving the emission reduction goals. Specifically, under the mass emissions cap and trade program, the agency will allocate to a source a number of allowances (NO_x emissions in tons) which a source would be allowed to emit during the calendar year. The source is not allowed to exceed this number of allowances granted unless they obtain additional allowances from another facility's surplus allowances. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet emission reduction requirements. The mix of control technologies can be greater because the owner can manage activity levels of equipment and place higher levels of control on high utilization units and less controls on less utilized units. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs.

An individual stated that the Chapter 117 requirements should only apply to industries within 27 miles of the central city on days when emissions are excessive (greater than 150 parts per billion) for more than two consecutive hours over two consecutive days.

The commission disagrees with the comment because such a proposal would not reduce emissions until an exceedance of the ozone standard had already occurred. As noted earlier in this preamble, reductions are required in the entire HGA ozone nonattainment area. Further, FCAA, §123, prohibits control techniques which are conditional upon atmospheric conditions.

TXU noted that the rule proposal preamble requested comments on allowing trading between different electric power generating companies in the DFW area to increase flexibility. TXU strongly supported development of such a rule and stated that the rule should allow simple trading between electric utilities with a program similar to the SB 7 trading provisions. TXU urged the commission to begin development of such a rule. TXU stated that the commission should also simultaneously develop a trading rule for inter-utility trading in the East Texas attainment area. TXU stated that such trading programs are essential in achieving the PUCT's objectives of minimizing cost and promoting potential competition for the cost-effective generation of electricity.

In response to the comments, the commission initiated rulemaking which would establish trading rules for DFW and east and central Texas. Specifically, the proposed new §117.109, System Cap Flexibility, §117.110, Change of Ownership--System Cap, and §117.139, System Cap Flexibility, would add flexibility to the trading of NO_x emissions in DFW and in east and central Texas by allowing the exceedance of a system emissions cap, provided emission reductions are obtained from another participant in a system cap to offset the exceedance. On November 15, 2000, the commission approved the proposed rules for publication in the *Texas Register*. (See the December 1, 2000 issue of the *Texas Register* (25 TexReg 11878).) Final action will be taken on this rule proposal by May 31, 2001.

TXI commented that its lightweight aggregate kilns are "an extremely small contributor to the total point source NO_x emissions in the HGA," and asserted that it is "widely known that the ozone problem in nonattainment areas are largely the result of mobile source emissions."

Even though lightweight aggregate kiln emissions form a relatively small fraction of the total emissions in HGA, the same can be said of most categories of emission sources. The commenter's logic of exempting all source sectors because each individually contributes only marginally to the area's ozone problem would cumulatively result in an inadequate plan for the area's attainment of the ozone standard due to no emissions reductions whatsoever. While mobile sources contribute a significant share of the ozone-forming pollutants in HGA, modeling analyses show that reducing mobile source emissions alone will not be sufficient to bring the area into attainment. In many cities with ozone problems, such as DFW and Atlanta, it is true that mobile source emissions are primarily responsible for ozone production, but even in those areas point sources make significant contributions. In the HGA emissions inventory projected to 2007, point sources contribute about 60% of the anthropogenic emissions of NO_x, which means that paradigms which apply to mobile source-dominated areas are not applicable in HGA.

The 2007 future emissions inventory was developed which included all applicable adopted state and federal controls. A number of sensitivity model runs were made with this inventory. These sensitivity analyses indicated that no one control measure would provide significant change in ozone concentrations. However, the modeling shows that when an ensemble of a number of controls were applied together, these will provide for significant reductions in ozone concentrations. The SIP outlines a number of controls that when applied together will provide for significant reductions in ozone.

TXI commented that its lightweight aggregate kilns in Clodine could not affect HGA generally and that all exceedances are to the east of the kilns.

Because significant contributions to air pollution occur throughout the HGA area, reductions from sources within Houston alone will not be enough to meet federal air quality standards. It is not surprising that exceedances in HGA have been documented only to the east of TXI's kilns since there are no air quality monitors to the west of Clodine.

TGP commented that many point sources operate only during fall and winter months and do not contribute significantly to ozone.

Ozone exceedances in HGA occur most frequently from early April to late October. In 2000, the first exceedance occurred on April 14, and the latest exceedance occurred on October 20. October and April comprise two of the months cited by the commenters as unnecessary for regulation. The commission's rules are written to prevent an ozone exceedance at any time of the ozone season.

Sierra-Houston commented that the commission did not conduct a model run with the specific Chapter 117 rules proposed, instead modeling an across-the-board 90% NO_x reduction, and that the commission has no SIP that the public can review and comment upon with accurate modeling.

Since the SIP revision was proposed, the commission has revised its modeling of point source emissions. Specific emission rates were modeled for all major EGFs in the area. Other point sources (with the exception of some minor NO_x sources such as flares) are now assumed to be reduced by 85% overall. It is reasonable to assume an across-the-board reduction for the non-EGFs, since in concurrent rulemaking published elsewhere in this issue of the *Texas Register* the commission adopted a mass emissions cap and trade program for HGA. Thus, modeling explicit reductions for all sources would be of limited benefit, since many sources will doubtless trade emissions allowances among themselves.

CAP commented that the commission should affirmatively demonstrate through photochemical modeling that whatever mix of control strategies is finally selected will be sufficient to achieve attainment by 2007.

The commission has used the best information available along with state-of-the-science modeling to develop a plan that is expected to bring the area into attainment by 2007. As new information and better science become available over the next several years, the commission will continue to evaluate plans for the area, and, if necessary, refine the plans to reflect the most current information.

Sierra-Houston resubmitted comment letters dated August 2, 1999, January 31, 2000, and February 24, 2000 concerning already-completed rulemakings and SIP revisions which Sierra-Houston had initially submitted during the comment period for these previous rulemakings and SIP revisions.

These comments were addressed in the ANALYSIS OF TESTIMONY section of the preambles to the earlier rulemakings and SIP revisions which were published in previous issues of the *Texas Register*.

Sierra-Houston commented on the NO_x emission reduction tables published in the August 25, 2000, issue of the *Texas Register* (25 TexReg 8479-8482). Sierra-Houston stated that the estimated reductions in the Tier I column plus the estimated reductions in the Tier II column do not add up to the estimated reductions in the Tier III column.

The Tier I column represents the estimated reductions resulting from combustion modifications, while the Tier II column represents the estimated reductions resulting from post-combustion controls. These columns list the estimated emission reductions if only these controls were applied. The Tier III column lists the estimated emission reductions if combustion modifications and post-combustion controls were applied. It is smaller than the sum of the Tier I and Tier II columns to avoid double-counting the emission reductions that would occur from the application of either Tier I or Tier II controls alone. In certain categories, such as process heaters, the Tier I reduction reflects maximal measures and the Tier III reduction is less than the maximal Tier I plus Tier II reduction, to reflect the mix of feasible reductions. The maximal levels in each Tier are not feasible on every unit.

Baker Botts commented that it generally supports the ongoing efforts by the commission to develop a SIP that is technologically achievable, economically reasonable, and legally approvable. Baker Botts, BCCA, Dynegy, Equistar, ExxonMobil, Goodyear, Harris County Judge Robert Eckels, Phillips 66, Spring Valley, TCC, TPIEC, TxOGA, Valero, and an individual commented that the commission should incorporate into the SIP a greater level of reductions from federally preempted sources and stated that EPA-regulated sources account for about 40% of the NO_x emissions in the HGA. The commenters stated that the EPA issued a number of regulations for some federally preempted sources, such as land-based spark engines, marine, recreational and land-based diesel engines, aircraft and locomotive engines, well after the FCAA deadlines, and that the EPA recently strengthened rules for on-road and non-road vehicles and fuels, such as low sulfur gas and diesel, Tier II motor vehicles, heavy-duty highway vehicle standards, and non-road Tier II/Tier III heavy-duty engine standards. The commenters stated that delays in implementing these rules have prompted the commission to propose technically and economically infeasible emission reductions from sources in HGA that the state has authority to regulate to make up for the missing federal reductions. The commenters stated that these delays have forced the commission to propose expensive regional fuels and significant use restriction regulations. The commenters stated that the commission and the EPA can ensure an equitable distribution of the compliance burdens necessary to meet mandated air quality improvement in HGA only by allowing the SIP to capture anticipated emission reductions from federally preempted sources. Baker Botts noted that the EPA demonstrated a willingness to assume responsibility for a portion of emission reductions created by a process in Los Angeles called a "public consultative process," that would resolve issues related to emissions from national and international sources, and that the EPA has also provided flexibility in obtaining offsets by allowing states to provide offsets to refiners based on emission reductions that the EPA projected would result from mobile sources using Tier II gasoline. Baker Botts suggested that this same sort of prospective crediting should be used to develop a more rational HGA SIP, and that the EPA should allow the commission to credit in the SIP the prospective emission reductions that will result from implementation of the Tier II gasoline rule and from other federally preempted sources. Finally, Baker Botts cited two cases wherein the District of Columbia Circuit has approved the EPA's flexibility with respect to statutory deadlines under the FCAA when the EPA has failed to meets its own deadlines, and this failure was deemed to upset the balanced federal/state responsibilities under the FCAA. ExxonMobil commented that it supports the commission and the EPA crediting the HGA SIP with an additional 60 tpd of federally preempted emission reductions that will occur over the next ten years. Harris County Judge Robert Eckels commented that the commission should work with the EPA to accelerate the implementation schedule for federally preempted emissions so that at least one-half of the related emission reductions are achieved by 2007, and that as a part of this process, the commission should delineate federal assignments detailing the engine standards and emission reductions necessary to achieve real and sustainable pollution reductions.

The commission agrees with the commenters that emission reductions from federally preempted sources would provide benefits for the HGA SIP demonstration, and the inability of the commission to regulate certain source categories has necessitated the use of other ozone control strategies. However, the commission understands that the EPA SIP approval process does not provide a mechanism for credit for emission reductions that occur after the attainment date. The commission understands that the EPA is not currently considering accelerating implementation schedules for existing federal rules. The commission is working with the EPA to determine the availability of SIP credit for many non-traditional control strategy mechanisms, like economic incentive programs and flexibility for preempted source categories. Additionally, the commission is working with the EPA to determine an appropriate federal contribution credit available for the HGA SIP.

RIA COMMENTS

BCCA, Entergy, ExxonMobil, Goodyear, GPA, Kinder Morgan, Lyondell, PECO, Phillips 66, REI, TPIEC, TXI, and TxOGA commented on the draft RIA and stated that the proposed rules were not evaluated in accordance with the analysis requirements for a major environmental rule. The commenters stated that Texas Government Code, §2001.0225, requires an RIA for certain major environmental rules. The commenters stated that the commission must consider the benefits and costs of the proposed rule in relationship to state agencies, local governments, the public, the regulated community, and the environment. The commenters stated further that the commission must also incorporate aspects of this analysis into the fiscal note in the proposed rules (e.g., identify the costs and the benefits; describe reasonable alternative methods for achieving the purpose of the rule considered by the agency; provide the reasons for rejecting those alternatives; and identify the data and methodology used in performing the analysis). The commenters stated that under §2001.0225(d) the commission must also find that "compared to the alternative proposals considered and rejected, the rule will result in the best combination of effectiveness in obtaining the desired results and of economic costs not materially greater than the costs of any alternative regulatory method considered."

The commenters stated that the rule proposal preamble's statement that the rules are exempt from the RIA requirement because federal law mandates the rules is a legally flawed effort to avoid an RIA and may render the rules invalid. The commenters stated that federal law does not mandate the control requirements, emission rates, and use restrictions contained in the proposal and asserted that many of the proposed rules exceed specific federal rules and standards applicable to the same sources. The commenters stated that examples of departures from the federal framework include the following: boiler, turbine, and other fired equipment emission limits set well below federal new source performance standards (NSPS), RACT, BACT, or lowest achievable emission rate (LAER) limits for the same sources; and compressor engine emission limits set at unprecedented low levels specifically designed to be unachievable and prevent the further use of the affected engines.

TXI 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. TXI 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." TXI stated that none of the state laws cited in the rule proposal preamble (TCAA, §§382.011, 382.012, and 382.017) is "an 'express requirements of state law' to adopt these NO_x emission rules."

TXI commented that *The Senate Natural Resources Committee, Interim Report to the 75th Legislature, Use of Cost Benefit Analysis in Environmental Regulation* (September 1996) regarding Texas Government Code, §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." (TXI's emphasis supplied).

TXI stated that the commission must quantify the costs associated with the proposal either for the purpose of determining the reasonableness of the proposed NO_x controls for achieving the commission's desired result or for complying with the specified requirements of Texas Government Code,§2001.0225. TXI asserted that the commission did not perform a study of the costs associated with the proposed rule for lightweight aggregate kilns. TXI also asserted that the commission did not perform a quantitative analysis of the estimated cost to the Texas lightweight aggregate industry and that without such an analysis, the commission cannot determine the reasonableness of the proposed rule from an economic perspective.

The commenters stated that the rule proposal preamble acknowledges that the rule proposal's components are "major environmental rules," but that the commission asserted that an RIA is "seldom" required and is only required for "extraordinary" rules. The commenters stated that these criteria appear nowhere in the RIA requirements. The commenters stated that the rule proposal preamble states that "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." The commenters stated that this "no greater than is necessary or appropriate" determination is the conclusion that an RIA is designed to evaluate and to offer for public review and comment. The commenters stated that the rule proposal is well beyond any federal mandates for the covered sources and are "extraordinary." The commenters stated that under Texas Government Code, §2001.0225, an RIA must be performed and offered for public comment before the proposal can be adopted.

The commission agrees with the commenters that the rules meet the definition of a major environmental rule; however, the commission disagrees that its interpretation of the exemption for federally mandated standards is legally flawed. While the rules may require significant capital investments by owners or operators of the types of units affected by these rules, that alone is not enough to trigger the RIA requirements. The Texas Government Code, §2001.0225, only applies to a major environmental rule adopted by a state agency, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopt a rule solely under the general powers of the agency instead of under a specific state law.

This rulemaking action does not meet any of these four applicability requirements, and is adopted in substantial compliance with the RIA requirements. Texas Government Code, §2001.035. These rules do not exceed an express standard set by federal law because the emission specifications are specifically developed to meet the ozone NAAQS set by the EPA under 42 USC, §7409. Title 42 USC, §7410, 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 42 USC, §7410, does not specifically prescribe programs, methods, or reductions to meet the federal 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 FCAA, Chapter 85, Air Pollution Prevention and Control). The FCAA does require some specific measures for SIP purposes, such as an inspection and maintenance program, but those programs are the exception, not the rule, in the federal SIP structure. 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. In order to avoid federal sanctions, states are not free to ignore the requirements of 42 USC, §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule. Failure to develop control strategies to demonstrate attainment can result in federal sanctions. Thus, while specific measures are not prescribed, both a plan and emission reductions are required to assure that the nonattainment areas of the state will be able to meet the attainment deadlines set by the FCAA. The EPA has provided the criteria for both the submission and evaluation of attainment demonstrations developed by states to comply with the FCAA. This criteria requires states to provide, in addition to other information, photochemical modeling and an analysis of specific emission reduction strategies necessary to attain the NAAQS. The commissions photochemical modeling and other analysis indicate that substantial emission reductions from both mobile and point source categories are necessary in order to demonstrate attainment. In this case, this rulemaking is intended, in part, to achieve reductions in ozone emissions in the HGA nonattainment areas. Specifically, as noted elsewhere in this rule preamble, the emission reductions associated with these rules are a necessary element of the attainment demonstration required by the FCAA. Further, these rules will also satisfy the NO_x RACT requirements at major sources in HGA which are not subject to the previous NO_x RACT rules. The FCAA, 42 USC, §7511a(f), requires any moderate, serious, severe, or extreme ozone nonattainment area to implement NO_x RACT, unless a demonstration is made that NO_x reductions would not contribute to or would not be necessary for attainment of the ozone standard. The adopted rules satisfy these federal requirements and are necessary to ensure that the current SIP revision in support of the HGA ozone attainment demonstration will be federally approvable.

This conclusion is supported by the legislative history for Texas Government Code, §2001.0225. During the 75th Legislative Session, SB 633 amended the Texas Government Code to require agencies to perform an RIA of certain rules. The intent of SB 633 was to require agencies to conduct an RIA of 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. 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. Because of the ongoing need to address nonattainment demonstrations required by federal law, the commission routinely proposes and adopts SIP rules. If each rule proposed for inclusion in the SIP was incorrectly considered as exceeding federal law, every SIP rule would require the full RIA contemplated by SB 633. This result would be inconsistent with the cost estimates and fiscal notes prepared by the commission and by the LBB. 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 meet the requirements under §2001.0225(a). 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. In other words, the adopted rules are intended to meet federal and state law, and does not go above and beyond what is required to meet federal or state statutes.

The commission has consistently applied this construction to its rules since this statute was enacted in 1997. Since that time, the legislature has revised the Texas Government Code but left this provision substantially unamended. Texas Government Code, Chapter 2001, presumes that "when an agency interpretation is in effect at the time the legislature amends the laws without making substantial change in the statute, the legislature is deemed to have accepted the agency's interpretation." *Central Power & Light Co. v. Sharp*, 919 S.W.2d 485, 489 (Tex. App. Austin 1995), *writ denied with per curiam opinion respecting another issue*, 960 S.W.2d 617 (Tex. 1997); *Bullock v. Marathon Oil Co.*, 798 S.W.2d 353, 357 (Tex. App. Austin 1990, no writ). *Cf. Humble Oil & Refining Co. v. Calvert*, 414 S.W.2d 172 (Tex. 1967); *Sharp v. House of Lloyd*, Inc., 815 S.W.2d 245 (Tex. 1991); *Southwestern Life Ins. Co. v. Montemayor*, 24 S.W.3d 581 (Tex. App.--Austin 2000, *pet. denied)*; and *Coastal Indust. Water Auth. v. Trinity Portland Cement Div.*, 563 S.W.2d 916 (Tex. 1978).

The commission's interpretation of the RIA requirements is also supported by a change made to the APA by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance." Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225, as falling under this standard. The commission has substantially complied with the requirements of §2001.0225.

Therefore, in addition to not exceeding an express standard set by federal law, these rules do not exceed state requirements, and are not adopted solely under the general powers of the agency because the provisions of the TCAA, §§382.011, 382.012, 382.016, 382.017, and 382.051(d), authorize the commission to implement a plan for the control of the state's air quality, including measures necessary to meet federal requirements. The remaining applicability criteria, pertaining to exceeding a delegation agreement or contract between the state and the federal government does not apply. Thus, the commission is not required to conduct a regulatory analysis as provided in Texas Government Code, §2001.0225.

REASONED JUSTIFICATION COMMENTS

Entergy, Enterprise, Equistar, Goodyear, Lyondell, PECO, Phillips 66, TPIEC, and TxOGA stated that the commission has not provided a reasoned justification for the proposal. The commenters asserted that a rule that would impose an air emission abatement requirement that is not demonstrated to be practical and economically feasible is directly contrary to the TCAA, §382.011(b), and therefore is inconsistent with the Texas Government Code, §2001.033(a)(1)(B) and §2001.035(c).

The commission has provided a "reasoned justification" for the rules in this adoption package as required by Texas Government Code, §2001.033. The requirement for a reasoned justification applies to the agency order finally adopting a rule. The standard for compliance with the reasoned justification requirement is substantial compliance, as determined by the Legislature, which amended the reasoned justification requirement in 1999. The commission has provided the factual, policy and legal bases for the rule, as required. Texas Government Code, §2001.024, requires only "a brief explanation" of the rules upon proposal in addition to other elements such as the fiscal note and public benefit evaluations. Both the rule proposal and adoption meet all of the requirements of the APA.

NOTICE COMMENTS

Entergy, ExxonMobil, Equistar, Lyondell, PECO, Phillips 66, REI, TPIEC, and TxOGA stated that the proposed rules did not include adequate notice as required under Texas Government Code, §2002.024. The commenters stated that Texas Government Code, §2001.024, requires adequate notice of a proposed rule, including information about its public benefits and costs. The commenters stated that adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule, and that courts have considered notice "adequate" only if: interested persons can confront the agency's factual suppositions and policy preconceptions; and the agency provides interested parties the opportunity to challenge the underlying factual data relied upon by the agency. The commenters asserted that in proposing the rules, the commission failed to provide interested parties with sufficient information to constitute adequate notice.

The commenters stated that the rule proposal preamble appears short of adequate notice because the cost estimates were "dramatically underestimated." The commenters stated that actual point source capital costs that would result from the rule proposal were in some instances ten to fifteen times the capital costs used in calculating the dollar-per-ton estimates in the preamble. The commenters stated that presenting a single average cost-per-ton figure for each point source category, instead of a range, masked the extremely high costs faced by some source categories. The commenters stated that the commission published insufficient information and analysis regarding costs and impacts.

The commenters noted further that the rule proposal preamble states that the cost estimates for controlling many point sources were "derived" from certain cost models and questioned how the costs were derived. The commenters also noted that the rule proposal preamble stated that "there may be individual sources for which the equipment actual control costs are higher than the ones identified in this cost note," and asserted that through this statement the commission "acknowledged that its estimates may have been low." The commenters stated that the commission published insufficient information and analysis regarding costs and impacts. The commenters stated that the commission "has not been completely responsive to stakeholder requests for information necessary to comment effectively" and "dramatically underestimated" the costs of the proposed control strategies, and that as a result, the notice of the proposal is inadequate.

The commenters stated that it has identified a number of critical gaps in the underlying factual data, methodology, and analysis in support of the proposed rules. The commenters asserted that the proposal included insufficient information and analysis regarding costs and impacts. The commenters asserted that the commission has not adequately responded to requests for additional information from stakeholders. The commenters stated that the following requests for information were outstanding: information regarding the modeling of emissions; information regarding the corrected emissions inventory database; and information supporting the estimated costs of control. The commenters stated that this information is necessary in order to comment effectively on the proposed rules and that data gaps in the proposal hindered effective comment. Solutia expressed similar concerns regarding the cost estimates.

The commission disagrees with the commenters and has made no change in response to these comments. Texas Government Code, §2001.024 requires that the notice of a proposed rule include certain information. Subsection (a)(5) requires that the notice state the public benefits expected as a result of the adoption of the proposed rule and the probable economic cost to persons required to comply with the rule. Adequate notice is essential for fairness as well as a meaningful opportunity to comment on a proposed rule. *United Loans, Inc. v. Pettijohn*, 955 S.W.2d 649, 651 (Tex. App.-Austin 1997). To achieve the goal of encouraging meaningful public participation in the formulation and adoption of rules by state agencies, the notice must have sufficient information so that interested persons can determine whether it is necessary for them to participate in order to protect their legal rights and privileges. The proposed rules contained an analysis of information available to the commission regarding the costs and benefits of the proposed rules. The preamble for the proposed rules contained a discussion of the FCAA requirements concerning the affected NO_x point sources, a detailed section by section discussion of the proposed changes, a fiscal note, including the cost to state and local governments, the public benefit and the estimated costs for the affected sources, a small and micro-business analysis, a draft RIA, a TIA, and a CMP consistency determination. The commission received intelligent comments which were substantial both in number and in scope, regarding the costs as well as the benefits. Therefore, the commission believes this goal has been achieved and that the notice includes sufficient information to constitute adequate notice.

The purpose of the comment period is for the public to provide the commission with information to say why they agree or disagree. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the notice must include the cost of a typical and reasonable method of compliance. The commenters' statements that the costs were "dramatically underestimated" did not state how that conclusion was reached. Mere disagreement with cost estimates does not render notice inadequate.

The proposed rules met the requirement to include sufficient information in explaining the requirements for NO_x point sources, the compliance schedule, the anticipated cost of compliance, and the anticipated reduction in emissions. To simply state that the proposal failed to provide sufficient information does not provide the commission with sufficient information to propose changes or alternative strategies. The commenters did not say how the notice is insufficient, but merely claimed that it is insufficient. Nevertheless, the commission has reviewed the notice and has determined it is adequate. The commission's responses to comments regarding costs associated with compliance with the rules are found later in this preamble. The commission is unaware of any requests for additional information to which it was not completely responsive.

LOCAL EMPLOYMENT IMPACT STATEMENT COMMENTS

Entergy, ExxonMobil, Equistar, Goodyear, Lyondell, Phillips 66, REI, TPIEC, and TxOGA stated that the proposed rules did not include the local employment impact statement required under Texas Government Code, §2001.022. The commenters stated that Texas Government Code, 2001.022, requires the commission to determine whether the rule proposal has the potential to affect a local economy before proposing the rule for adoption. The commenters stated that if answered affirmatively, the commission must request that the Texas Employment Commission to prepare a local employment impact statement describing in detail the probable effect of the rule on employment in each geographic area affected by the rule for each year of the first five years that the rule will be in effect. The commenters further asserted that the commission failed to make the required initial determination and ignored the potential for the proposal to adversely affect the local economy. The commenters stated that a local employment impact statement should have been requested and prepared in advance of the proposal.

The commission agrees with the commenters that the adopted rules may affect a local economy; however, it does not agree that it is the responsibility of the commission to provide the local employment impact analysis. The APA requires state agencies to determine whether a rule may affect a local economy before proposing a rule for adoption. If the agency determines that a proposed rule may affect a local economy, the agency must send a copy of the proposed rule and other information to the Texas Workforce Commission (Workforce Commission) before the agency files notice of the proposed rule with the secretary of state. The APA requires the Workforce Commission to prepare a local employment impact statement for proposed rules, if a state agency requests the statement. The commission determined that the proposed rules might affect a local economy, and sent the proposed rules and other requested information to the Workforce Commission. The commission received a letter from the Workforce Commission, indicating that the Workforce Commission did not have the ability to determine the potential local employment impacts from the proposed rules.

TIA COMMENTS

Entergy, ExxonMobil, Equistar, Goodyear, Lyondell, Phillips 66, REI, TPIEC, and TxOGA stated that the proposed rules did not include an adequate TIA as required under Texas Government Code, §2007, with Goodyear stating that the proposal amounts to a taking of its engines (including a recently retrofitted engine) "not supported by adequate scientific support, public participation, or legal process." The commenters stated that the TIA provision mandates that covered agencies "take a 'hard look' at the private real property implications of the actions they undertake...," according to the Office of the Attorney General, *Private Real Property Rights Preservation Act Guidelines*, (21 TexReg 387, January 12, 1996). The commenters stated that under §2007.043, a TIA must describe the specific purpose of the proposed action, determine whether engaging in the proposed governmental action will constitute a taking, and describe reasonable alternative actions that could accomplish the specified purpose. The commenters stated that the agency must also explain whether these alternative actions also would constitute takings.

The commenters stated that agencies must also comply with guidelines developed by the Texas Attorney General when developing the TIA and that according to these guidelines, agencies must carefully review governmental actions that have a significant impact on the owner's economic interest. The commenters stated that these guidelines include the statement: "Although a reduction in property value alone may not be a 'taking,' a severe reduction in property value often indicates a reduction or elimination of reasonably profitable uses." (21 TexReg 392, January 12, 1996). The commenters stated that examples of aspects of the rule proposal that could significantly impact private real property in a manner that constitutes a taking include gas-fired compressor engines and other point source NO_x controls. The commenters stated that the rule proposal preamble acknowledged that retrofitting compressor engines to the level specified in the proposal is infeasible (25 TexReg 8137 and 8291), and stated that the existing equipment, representing a significant capital improvement at a number of industrial sites, would be rendered unusable. The commenters stated that the 90% point source reduction requirement is economically and technologically infeasible for a number of existing sites, and that this requirement could cause a number of facilities to shut down their operations, dramatically impacting the value of their real property.

The commenters stated that the proposed rule preamble acknowledged that some of the rules may "burden" private real property but claimed an exemption from performing a TIA based on the assertion that the proposal does not impose a greater burden than necessary to advance a health and safety purpose and that the proposal "reasonably" fulfills a federal mandate. The commenters stated that the commission provided the public no basis to infer that a cost/benefit analysis or a reasonableness determination was, in fact, performed as necessary to support the TIA exemption claim because the preamble contains only the bare assertions. The commenters asserted that the proposed rules will impose a greater burden than is necessary, and are not reasonably taken to fulfill a federal mandate. The commenters commented that according to the Attorney General's Guidelines, a full TIA was required to be completed with the proposal, and that failure to perform a TIA could invalidate the rules.

As stated previously in the preamble, the purpose of the adopted rules is to ensure emission reductions which will result in reductions in ozone formation in the HGA ozone nonattainment area and help bring HGA into compliance with the air quality standards established under federal law as NAAQS for ozone and to satisfy the NO_x RACT requirements at major sources in HGA which are not subject to the previous NO_x RACT rules. The acknowledgment that the rules may require a capital investment or the installation of controls, is simply that, an acknowledgment. The commission understands that the rules may have an impact on real property and in noting this, sought comments on any potential impact to ensure that the adopted rules are technically and economically feasible. The commission believes that this acknowledgment has caused the commenters to misunderstand the commission's interpretation of the requirements of Texas Government Code, Chapter 2007. The commission does not believe that the assessment required by Chapter 2007 begins with a determination of whether or not the proposed rules could result in a capital expenditure. Rather, the commission believes that before an assessment is required, the commission must determine whether Chapter 2007 applies to the government action. If the proposed action is subject to an exception to Chapter 2007, the analysis is complete. Section 2007.003(b) provides that "this chapter does not apply to the following governmental actions:...." Because the commission believes the adopted rules meet the two exceptions to Chapter 2007 discussed below, the full takings impact assessment is not required for the rules.

The commission believes the adopted rules are exempt under Texas Government Code, §2007.003(b)(4), because they are reasonably taken to fulfill an obligation mandated by federal law. While several governmental actions are subject to being reviewed under Chapter 2007, including the adoption of rules, §2007.003(b)(4) specifically excludes an action that is reasonably taken to fulfill an obligation mandated by federal law. The rules are adopted to meet the air quality standards established under federal law as NAAQS. The commission also believes that the adopted rules meet an additional exception to the requirements of Texas Government Code, Chapter 2007. Texas Government Code, §2007.003(b)(13), states that Chapter 2007 does not apply to an action that: 1) is taken in response to a real and substantial threat to public health and safety; 2) is designed to significantly advance the health and safety purpose; and 3) does not impose a greater burden than is necessary to achieve the health and safety purpose. Although the rule revisions 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 significantly advance the health and safety purpose. This action is taken in response to the HGA area exceeding the federal ambient air quality standard for ground-level ozone, which adversely affects public health, primarily through irritation of the lungs. The action significantly advances the health and safety purpose by reducing ozone levels in HGA. Consequently, these rules meet the exemption in §2007.003(b)(13). The commission has included elsewhere in this preamble its reasoned justification for adopting this strategy and has explained why it is a necessary component of the SIP which is federally mandated. This discussion, as well as the HGA SIP which is being adopted concurrently, explains in detail that every rule in the HGA SIP package is necessary and that none of the reductions in those packages represent more than is necessary to bring the area into attainment with the NAAQS. This rulemaking therefore meets the requirements of Texas Government Code, §2007.003(b)(4) and (13). For these reasons the rules do not constitute a takings under Chapter 2007 and do not require additional analysis.

SMALL BUSINESS AND MICRO-BUSINESS ASSESSMENT COMMENTS

Entergy, ExxonMobil, Equistar, Goodyear, Lyondell, Phillips 66, REI, TPIEC, and TxOGA stated that the proposed rules did not include an adequate small business and micro-business assessment as required under Texas Government Code, §2006.002. The commenters stated that an analysis of the costs of compliance for small and micro-businesses must also compare the costs of compliance for these businesses with the costs for the largest businesses affected by the rule. The commenters stated that the comparison must use at least one of the following standards: cost for each employee, cost for each hour of labor, or cost for each $100 of sales. The commenters asserted that the rule proposal failed to include the mandated cost comparison standards. The commenters stated that this is the case even in those instances where the commission acknowledged a significant impact. The commenters stated that the commission either restated the costs of compliance it identified in the analysis of public benefits and costs, or concluded that it cannot determine the cost to small businesses. The commenters stated that the rule proposal preamble stated that "the estimated capital and annualized cost of installing and operating control technology used for the various types of equipment in fiscal note would appear to be a reasonable cost estimate for small and micro-businesses." (25 TexReg 8293).

The commenters asserted that the rule proposal's assessments fall short of what Texas law requires and that it is not sufficient for the agency merely to state that the costs for small and large businesses will be the same. The commenters stated that the rationale behind requiring a comparison using an established standard (e.g., cost for each employee, cost for each hour of labor, or cost for each $100 of sales) is to determine whether there is a disparate impact on small businesses. The commenters stated that according to *Unified Loans v. Pettijohn*, 955 S.W.2d at 652 (Court of Appeals--Austin, 1997), the statute's purpose is to obtain "an objective assessment of the agency's proposed action by forcing it to consider seriously. . . the effect of the rule on small businesses, including an analysis of their costs of (compliance) and a comparison of their costs with the cost of compliance for the largest businesses affected. ..." The commenters stated further that the commission cannot merely conclude that the costs to small businesses "cannot be determined," and is obliged to include in the notice "some basis" for its conclusion so that interested parties can "confront that basis in a meaningful way in their comments." (*Unified Loans v. Pettijohn*, 955 S.W.2d at 653.)

The commenters stated that in the rule proposal preamble, the commission did not publish the information mandated by Texas law and that as a result, it is impossible for the public to comment on whether the agency adequately considered the effect of the rule on small businesses, thus rendering the notice of the plan inadequate. The commenters stated that Texas Government Code, §2006.002, requires the commission to provide a comparison of the proposed rule's impact on small and large businesses, using the specified standards, for public review and comment before adoption.

The commission stated in the small business and micro-business assessment in proposal preamble that it was unable to identify any such businesses that would be affected by the proposed amendments. (See the August 25, 2000 issue of the *Texas Register* (25 TexReg 8293).) Since the commission was unable to identify any small or micro-businesses or know which facilities subject to these emission specifications are owned by small or micro-businesses, it was not possible to provide an analysis based on the number of employees, hours of labor, or amount of sales income. Nevertheless, in order to provide a basis for comments on the potential impacts for small or micro-businesses, the commission estimated, to the extent possible, the costs based on the estimated annualized cost for installing and operating control technology in dollars per ton of NO_x reduced that was used for various types of units in the fiscal note in the proposal preamble. Since the commission did not have access to the information contemplated by the statute, the use of an annualized cost was a meaningful way to provide sufficient notice of the cost to small and micro-businesses, and therefore meets the objective of Texas Government Code, Chapter 2006. Although the commission received numerous comments on the rules, none of the commenters identified themselves as small or micro-businesses.

TECHNICAL FEASIBILITY--GENERAL COMMENTS

BP stated that the emission specifications are technically feasible at its plants, except in a "very *limited* number of combustion sources. (BP's emphasis supplied). BCCA stated that the emission specifications are technically infeasible and have no proven performance experience upon which to base a reasonable and technically viable regulatory program. BCCA commented that technologies for reducing NO_x emissions are available for a wide range of processes and combustion devices, but stated that these technologies alone will not produce a 90% reduction in NO_x emissions. Crown, Harris County Judge Robert Eckels, RAQCG, and Union Carbide questioned the technical feasibility of meeting the proposed limits. BCCA stated that three key options for NO_x control are available: application of retrofit control technology on existing equipment; replacement or consolidation of existing equipment; and shutdown of existing equipment. BCCA asserted that there is no evidence in the proposed rule that the commission weighed and analyzed the technical feasibility of the potential control options that operators will be required to use to reach NO_x reduction targets, and that the commission has assumed that retrofit control technology on existing equipment will work in all cases.

The commission agrees that application of retrofit control technology on existing equipment, replacement or consolidation of existing equipment, and shutdown of existing equipment are possible options for reducing NO_x. The commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of the adopted ESADs. The commission is aware that there undoubtedly will be cases in which an owner or operator evaluates the circumstances of a particular unit and determines, for whatever reason, to pursue an option other than retrofit control technology. The commission has determined that the various controls which can be used to meet the ESADs have a proven performance experience and agrees with BP that the 90% reductions are technically feasible. A detailed explanation of how the commission has reached these conclusions is provided in the responses to comments later in this preamble.

Baytown, Baytown COC, BCCA, EHCMA, Entergy, Enterprise, ExxonMobil, Lyondell-Citgo, TABCC, Phillips 66, Union Carbide, Valero, and nine individuals recommended that the ESADs be revised to require approximately 75% NO_x reductions (i.e., comparable to the rules in California's South Coast Air Quality Management District (SCAQMD)) rather than 90% as proposed. BP and GHASP supported the proposed 90% NO_x reductions.

The commission retained most components of the measures associated with the 90% point source NO_x reductions because anything less would jeopardize the approvability of the attainment plan. After estimating for emissions of new sources and making some adjustments to reflect technical feasibility issues, the overall reduction is estimated at 85%.

CAP stated that the 90% reductions appear to be greater than those required in any other nonattainment area.

Because of Houston's unique circumstances, it is unlikely that another nonattainment area will require as large a point source reduction. The reductions required to meet the standard depend on the number and degree of exceedances. Currently, only Los Angeles has ozone exceedances in number and degree similar to Houston's. The intensity of summertime sunlight is also a factor, which puts cities in southern latitudes like Los Angeles and Houston at a disadvantage in comparison to more northern cities. Singularly, Houston has the highest percentage of point source NO_x emissions of total NO_x emissions of the nine severe and one extreme ozone nonattainment areas in the United States.

There are other large urban areas with a severe ozone designation and a petroleum refining presence, such as Philadelphia.

Philadelphia, however, is primarily basing its current attainment projections on reductions in regionally transported ozone. Likewise, Milwaukee and Chicago are focusing on reductions in regionally transported ozone. Some of the other severe ozone nonattainment areas have not completed development of their emission specifications for the one-hour attainment demonstrations required by the 1990 FCAA.

In addition, areas in the country other than Houston have large concentrations of refining and petrochemical plants. Most of these areas have smaller populations and less total on-road and non-road emissions, and therefore either already attain the one-hour ozone standard or are predicted to attain the standard with far more modest reductions than required in Houston. Such areas include Corpus Christi, BPA, and Lake Charles, Louisiana.

BCCA suggested that the commission consider establishing a partnership with the regulated community to develop technologically feasible standards for point source categories which have very few, if any, NO_x retrofit applications in the United States. BCCA stated that examples of these sources include ethylene plant pyrolysis furnaces, lean-burn IC engines, hydrogen generation reactor furnaces, BIF units and other incinerators, and FCCUs.

The commission appreciates BCCA's offer of cooperation. The commission has based the ESADs on its own analysis of technical feasibility, which included seeking factual input from the regulated community. The commission notes several points in response to these comments. First, the frame of reference for retrofit experience is not limited to the United States. Much experience with SCR was obtained in Japan and Germany in the 1980s before significant commercial operation of SCR in the United States. Second, there are a large number of lean-burn IC engine retrofits in the United States as a result of the NO_x RACT requirements of the FCAA, 42 USC, §7511a(f).

BCCA, Entergy, Equistar, ExxonMobil, and Lyondell asserted that most of the emission limitations were developed with a less than complete analysis of the technical feasibility of the proposed controls.

The commission analyzed the technical feasibility of each proposed ESAD and did not propose any it believed to be technically infeasible. There are a vast number of point sources in the HGA area and it would have been impractical for the commission to assess many specifics of individual emission units, such as locating available space for SCR, which will be a key factor in many retrofit applications. Because an exhaust stream can be ducted some distance to a SCR, space is ultimately a cost issue. Many of the concerns raised by the commenters with regard to the technical feasibility of the measures relate more to the potential costs. The commission has re-examined the issues of technical feasibility in response to public comment. After considering the technical feasibility issues raised by commenters it has adjusted several standards where it believes the case has been made that the level of control is not demonstrated and may be impracticable.

BCCA and ExxonMobil stated that the commission appears to have first established an arbitrary NO_x reduction target for point sources (i.e., 90%) and, through an iterative process, back-calculated the emission limits necessary to achieve the desired target. BCCA and ExxonMobil stated that this is "an arbitrary approach to establishing air pollution standards, and circumvents the intent established in the Texas Clean Air Act to establish standard based on a technological and economical review of available control measures."

The 90% point source emission reduction target was not developed arbitrarily. It was proposed and adopted in the May 1998 modeling SIP submitted to the EPA, as a high level estimate of technical feasibility of applying maximal point source NO_x controls. The May 1998 modeling SIP was subject to public notice and comment. The logic for the 90% NO_x reduction was based on non-arbitrary premises: first, that SCR is physically capable of achieving this kind of NO_x reduction on most exhaust streams, and second, that the technology has been applied to only a handful of units in HGA and thus is likely to be available areawide to achieve substantial reductions. The ability of combustion modifications to provide an increased share of the reductions in those cases where SCR could not provide a full 90% reduction was also considered. The 90% point source target remained as a policy goal because subsequent iterations of modeling and investigations into the feasible reductions in other categories led to the conclusion that attainment of the ozone NAAQS in HGA by 2007 would necessitate this level of point source reduction, if not more. Point source NO_x reductions in the range of 90% require the combined use of combustion modification controls (Tier I) and flue gas clean up controls (Tier II) on the majority of large combustion units. This combination of controls is referred to as Tier III. Despite the apparent logic behind the Tier III approach that even higher reductions than 90% could be achieved if Tier III were applied to approximately 1,200 small boilers, heaters, and incinerators, the commission retained the May 1998 goal of 90% reduction in the August, 2000 rule development. Proposing NO_x reductions less than 90% could have jeopardized the success of the plan. Greater than 90% NO_x reductions would have resulted in increased economic burdens on a numerically large number of sources contributing only a small portion of total point source emissions.

In the work leading to the August, 2000 rule proposal, the commission staff evaluated the 1997 emissions inventory in detail and considered various combinations of emission specifications for various categories of equipment to achieve a 90% NO_x reduction. The result of this analysis was that a 90% NO_x reduction would require ESADs very near technically feasible Tier III limits for many categories. The design of the ESADs by category to achieve a concrete policy goal of a 90% reduction also enabled the commission to propose ESADs for a vast number of very small heaters and boilers at Tier I levels, which is key to the practicability of the adopted plan. Comparability of emission rates across equipment types was a consideration. For example, the adopted ESAD applicable to existing gas turbines rated at less than 1.0 MW is comparable to the adopted ESAD for lean-burn engines. The usage of units in these two categories are very similar. Responses to comments concerning costs are discussed in detail later in this preamble under the heading of *COST*.

BCCA asserted that the NO_x SIP point source rule proposal preamble lacks valid, current, and adequate scientific and technical support for the proposed NO_x reduction targets. BCCA asserted that there is no discussion indicating the use of actual industry or vendor retrofit experience which would otherwise precede a determination that the proposed NO_x reduction target is broadly achievable for all point sources categories, and that the commission failed to take the worldwide lack of retrofit experience into account when setting the proposed emission limits. BCCA asserted that there is no discussion or consideration of design and implementation timing issues, which will impact the technological feasibility of the required technology applications.

Achieving the point source NO_x standards requires the combined use of combustion modification controls and flue gas clean up controls on the majority of large combustion units to achieve approximately 90% reduction. The adopted NO_x reduction targets for utility boilers, gas turbines, industrial boilers and heaters above 40 MMBtu/hr heat input are based on the combined application of combustion modifications and flue gas controls. The estimates of percentage reductions achievable with these technologies applied separately was laid out in the preamble of the proposal to this rulemaking, in the table "Subcategories--Point Source Potential NO_x Emission Reductions by Subcategory for Houston/Galveston Nonattainment Area Counties." (See the August 25, 2000 issue of the *Texas Register* (25 TexReg 8480-8482).) The combined capabilities of the technologies in most cases exceed the target specifications and will allow for meaningful choices in the degree of application of each one.

The capabilities of combustion modifications are well documented in the literature, including the NO_x control literature cited in the rule cost note section of the preamble. These documents report combustion based reductions from minimal to over 90%. Reduction capabilities as reported in the literature continue to improve. Theoretically, combustion modifications are capable of a 90% reduction, and in recent practice, a few low-NO_x burner retrofits in commercial operation are achieving this level. The basic principles of NO_x formation have been understood since the 1940s when Zeldovich developed the chemical mechanism for NO_x formation which explained its dependence on temperature in a flame. Some NO_x reduction efforts date back to the 1950s.

Today's understanding of NO_x formation includes three different mechanisms for generation of NO_x. Thermal NO_x is formed by the oxidation of atmospheric nitrogen present in the combustion air, prompt NO_x is produced by high speed reactions at the flame front, and fuel NO_x is formed by the oxidation of nitrogen contained in the fuel. Prompt NO_x is more likely to form in a fuel-rich environment because of its dependence on hydrocarbon fragments. This is very different than thermal NO_x, which is highly dependent upon air concentrations.

Because the temperature requirements of commercial processes are in most cases lower than the temperatures at which most NO_x forms, low-NO_x combustion development will continue to approach the single digit NO_x ppm reflected in the adopted specifications. In fact, one vendor has provided several dozen retrofits, primarily on gas-fired boilers in commercial service today, achieving levels of nine ppm or less. These applications represent one end of a spectrum of capabilities of low-NO_x combustion retrofits.

Combustion technology continues to develop rapidly since the late 1980s when a number of California districts set retrofit NO_x control standards. The literature of the early 1990s cites combustion technology retrofit capabilities of 50-75% reductions on gas-fired boilers; today 60% reduction is being achieved on one of the coal-fired electric utility boilers in Houston through retrofitting with low-NO_x combustion technology. Many of the units in low-NO_x operation today were retrofit in the early 1990s because of SIP limits that were set in the late 1980s in areas such as SCAQMD, Ventura County Air Pollution Control District (VCAPCD), and the Bay Area Air Quality Management District (BAAQMD) in California. Both combustion modifications and flue gas cleanup are established technologies, documented in the NO_x control literature, including the EPA alternative control techniques (ACT) guidance documents, papers at numerous meetings of research and trade organizations for industry, NO_x control vendors, constructors, and the government. The number of low-NO_x applications has grown steadily worldwide since the early 1990s as a number of other countries also have addressed problems related to NO_x emissions, including smog and acid deposition. During the 1990s, the capabilities of NO_x technology advanced and a solid experience base was created. This may be why there is lack of consensus among the owners or operators of major sources on the technical feasibility of the ESADs and why the vendor community views these limits as technically feasible.

From the standpoint of establishing the technical feasibility of the Tier II reductions, there is no worldwide lack of retrofit experience. SCR is the basic Tier II flue gas NO_x control technology. Most of the reductions achieved by SCR have come from retrofit applications. Also, technology is replicable, so in a true sense, the first successful SCR project was sufficient to demonstrate its feasibility. With more than 500 applications of SCR reported by 1997 and growing rapidly, in many different exhaust streams with widely varying degrees of temperature and contaminants, its technical feasibility is not a question. Further, the distinctions between new and retrofit applications involve issues of cost rather than technical feasibility.

The literature cited in the preamble and many other sources indicate the capability of SCR technology to remove more than 90% of the NO_x from a variety of streams. The removal efficiency is a design criteria, 90% in some new source applications being an inflection point of maximum cost effectiveness in dollars per ton of NO_x removal. In retrofit cases, less than 90% removal with SCR may be the most cost-effective approach because of space or other existing constraints.

Combustion modifications can address SCR constraints, reducing the overall amount of reduction required by SCR, resulting in smaller and fewer SCRs than otherwise would be necessary. The subcategories table in the Tables and Graphics section of this issue of the *Texas Register*, titled "Subcategories--Point Source Potential NO_x Emission Reductions for Houston/Galveston Nonattainment Area Counties" illustrates the overlap in capability between combustion modifications and SCR to meet the ESADs. In the subcategory of medium process heaters, the Tier I reduction of 49% represents an emission level of 0.060 lb/MMBtu, whereas the Tier II reduction of 90% is equal to the ESAD of 0.010 lb/MMBtu. To achieve the ESAD, the SCR efficiency would need to be 83% on a unit achieving 0.060 lb/MMBtu with combustion modifications, or 67% on a unit achieving 0.030 lb/MMBtu, illustrating the potential for lessened demand on SCR. In the subcategories of smallest heaters and boilers, combustion modifications will be the only technology required. Even in the absence of a cap and trade program, the number of SCRs needed would be less than 100% of the medium and large size units because a few units can achieve the 8 and 12 ppm targets with current combustion technology. The number of SCRs is likely to decrease further because of the continuing advancement of combustion technology.

There are few retrofits operating at the large unit ESAD levels because few other retrofit rules are as stringent. Notably, where the levels are as stringent, such as VCAPCD Rule 59 for utility boilers, the retrofit operating levels are below the ESADs. A logical point of comparison for industrial sources is the Los Angeles retrofit standards set by the SCAQMD. The refinery boiler and heater retrofit limit of 0.030 lb NO_x/MMBtu was adopted in 1988. The gas turbine limit of nine ppm was adopted in 1989. The differences between the SCAQMD standards set in the late 1980s and the 2000 HGA ESADs are significant: the boiler and heater ESADs are set at 0.030 for small, 0.015 for medium, and 0.010 for large chemical and refinery boilers and heaters, and four ppm for gas turbines. In the time between setting the SCAQMD limits and the ESADs, the NO_x control technologies have advanced and become widely demonstrated, as a result of implementing the SCAQMD standards, similar standards in other California districts, and the NO_x RACT and acid rain requirements of the 1990 FCAA. It is also clear from the numerous technical innovations under development today that NO_x control technology is continuing to improve rapidly.

The implementation schedule and the technical feasibility have been analyzed separately in this adoption preamble in order to show as clearly as possible the reasoning the commission used in adopting the ESADs and in developing the compliance schedule. The commission has tried to use the term technical feasibility in a sense that does not depend on the schedule. What is technically feasible is a function of the state of current engineering practice. The appropriate schedule for applying the technically feasible controls is a function of the practicability (or difficulty) of a certain rate of application. In other words, control measures which are technically feasible remain so, but there needs to be a feasible schedule to apply them. Responses to comments concerning the compliance schedule are discussed in detail later in this preamble under the heading of *COMPLIANCE SCHEDULE*.

BCCA, Equistar, Goodyear, Lyondell, PECO, and TPIEC stated that although technology has advanced in recent years, there is no one demonstrated, commercialized, retrofit technology application today to achieve the 90% NO_x reduction target for the point source category. BCCA stated that there are other steps that must be taken to achieve the 90% reduction target, such as wholesale replacement of sources, consolidation of sources to reduce fuel firing, and shutdown of marginally economic equipment and plants. BCCA stated that it does not believe such steps are technologically based emission control standards.

The commission agrees that there is no one demonstrated, commercialized, retrofit technology application that will be used to achieve the 90% NO_x reduction target for the point source category. Tier III emission standards are a combination of two broad types of technology, combustion modification and flue gas cleanup. Within these broad categories, there are numerous demonstrated technologies and promising new ones moving rapidly to commercial demonstration. The diverse circumstances of several thousand point sources, most of which will have to reduce NO_x emissions even under cap and trade, will result in a variety of technologies to be applied. The commission disagrees that the standards are not technologically based. As discussed in several responses in this section, the combination of combustion modifications and flue gas cleanup has been demonstrated to achieve emission levels equal to and surpassing the ESADs on specific units in commercial operation. There will soon be other units in the SCAQMD, because a stream of new permits is issued at lower rates after a new level of NO_x is demonstrated. The commission agrees that some valid compliance strategies could involve reduced fuel firing and shutdown of marginally economic equipment and production lines. These strategies are not technologies, but market responses to requirements to reduce emissions.

BCCA, Lyondell, and Equistar stated that post-combustion NO_x reduction retrofit controls (e.g., SCR) have not been demonstrated to achieve the desired low level of NO_x emissions envisioned by the proposal. Dynegy stated that because SCR does not have a demonstrated performance history in many applications, it is questionable whether SCR represents a practical and feasible method of control. Dynegy said there is no scientific basis to assert that SCR can consistently achieve the reduction levels set forth in the proposal.

Where it has been required by regulation, such as VCAPCD Rule 59, SCR has been demonstrated to achieve the lowest level of NO_x emissions envisioned by the proposal, 0.01 lb NOx/MMBtu. The commission agrees that SCR alone is not sufficient. The lowest levels of NO_x ESADs are based on the Tier III approach of combining combustion modifications (Tier I) and flue gas cleanup (Tier II), rather than on Tier II alone. SCR is a versatile, demonstrated retrofit technology expected to be used for most of the larger industrial boilers and process heaters. SCR is capable of reducing 90% or more from most combustion exhaust streams, but like any other technology, is not ideally suited for all applications. Combustion controls are developing dynamically, achieving teen and even single digit NO_x ppm in a growing number of applications. Although the number of SCR retrofits is expected to be unprecedented, the total number of SCRs used will depend on the extent to which combustion controls approach the 8 ppm and 12 ppm ESADs for large and medium units, respectively, and the extent to which they exceed the 30 ppm ESAD for most small units. Similarly, SCRs will be downsized for some units because combustion controls will bear more of the reduction.

BCCA stated that both combustion control improvements and post combustion retrofit controls have technological limitations that reduce their potential effectiveness in achieving the desired emission reduction targets. BCCA stated further that retrofit combustion controls (e.g., low-NO_x burners) will result in a decrease in combustion unit capacity (i.e., de-rate) in up to 15% of the technology applications.

BCCA did not explain how it concluded that retrofit combustion controls (e.g., low-NO_x burners) will result in a decrease in combustion unit capacity (i.e., de-rate) in up to 15% of the technology applications. The commission believes that the combined capabilities of Tier I and Tier II technologies will operate in tandem to minimize these additional costs.

BCCA stated that the proposed emission limits will be unachievable by combustion retrofits for many sources and will require extensive implementation of SCR on an unprecedented and untested scale.

The commission agrees that the number of SCRs required will be unprecedented. This is not the same as being untested. As described elsewhere in this preamble, SCR is one of many tested and proven technologies available to reduce NO_x emissions.

BCCA stated that in retrofit applications, there are many engineering and design uncertainties that must be addressed including achieving the desired NO_x performance, assuring manufacturing capacity is maintained, and assuring that operating productivity and reliability is maintained.

The commission agrees that these are some of the key engineering and design uncertainties that must be addressed in designing NO_x retrofits.

BCCA and TCC stated that in post-combustion control technology retrofit applications, there are many factors that can reduce not only NO_x performance, but also process unit capacity, equipment operating productivity, and equipment reliability. BCCA and TCC also stated that in many retrofit applications, SCR cannot simply be placed at the end of the flue-gas handling system, but must be designed and located in the correct temperature zone of the flue-gas handling system to ensure proper operation. BCCA stated that the lower temperature limit in the design of the low-temperature SCR systems is 300 degrees Fahrenheit. BCCA stated that units designed specifically for the transfer of heat to process streams (or to capture exhaust gas heat, in the case of duct burners) often have stack exit temperatures below 300 degrees Fahrenheit. BCCA stated that unless space is available in the proper temperature zone of the heat recovery system, major system modifications must be made to accommodate the SCR retrofit and that in some installations there can be significant engineering obstacles to changing the design of the heat recovery system while maintaining system efficiency.

The commission agrees that compliance with the ESADs will be technically challenging. However, as described elsewhere in this preamble, the adopted ESADs are technically feasible. The commission notes several low-temperature SCRs are referenced as 250 degrees Fahrenheit applications.

BCCA stated that the addition of the SCR reactor to the flue gas path will increase pressure drop, which will reduce the firing rate if the loss is not compensated for through the addition of fans (either larger or new) to duct the hot flue-gas through the SCR catalyst bed. BCCA stated that this will result in additional load on the site infrastructure, both electrical and steam production, as well as reduce the capacity or production rate of the unit.

The commission does not disagree that SCRs add pressure drop, but believes the commenter is overstating the effect for units which have fans. The added pressure drop is a few inches water column. With low-temperature SCR, the pressure drop may be 0.25 inch. According to the 1998 NESCAUM report on utility NO_x control, a heat rate penalty of 0.25% is considered typical for gas-fired boilers (Appendix D) and 0.5% represents the high end of the literature for gas and coal units (page 95). The report also states that of more than 200 utility boiler SCR retrofits performed in Europe, Japan, or the United States, none required conversion from forced draft to balanced draft design (pp. 57-58). The report indicates that stand-alone SCR designs can be engineered for low system draft losses more easily than in-duct designs, but depending on the additional ducting distance, there may not be a net improvement in draft loss. Long runs of duct work could require new or upgraded fans. Typically, the additional pressure drop from SCR retrofit is not large enough to require new or upgraded fans. An exception to this is natural draft refinery heaters, which do not have fans.

BCCA stated that it identified less than two dozen SCR retrofit applications in the United States, compared with the 1,800 potential applications expected under the proposed rules. BCCA stated that this very limited retrofit experience would not even qualify SCR as a maximum achievable control technology (MACT) standard for air toxics and is therefore not sufficiently broad for industry to apply and extend confidently across all the regulated sources in the HGA under RACT standards.

There are more than two dozen SCR retrofit applications in the United States. The Institute of Clean Air Companies, an organization based in the United States, has identified more than 500 SCR installations worldwide on a variety of units, many of which are similar to those in HGA and very many of them retrofit applications. The challenges of retrofits in HGA will be similar to units which have already been retrofitted with SCR. The EPA bases MACT standards on its determination of the best performing 12% of existing sources for each particular source category and, significantly, this is regardless of the status of the emission controls as grassroots or retrofit. Whether or not existing SCR applications in the United States are numerous enough in any particular source category for the EPA to determine that they represent the best performing 12% of existing sources for that source category is not relevant to the selection of ESADs. The commenter's position implies that a particular control technology is technically feasible only when there are sufficient retrofit installations of that specific control technology to represent greater than some percentage of the existing sources. As noted earlier, technology is replicable, so in a true sense, the first successful SCR project was sufficient to demonstrate its technical feasibility. Also, installation of a control technology at a source in one source category often can be "transferred" to other source categories. In addition, the commission notes that the ESADs do not represent RACT, but instead were developed in order for HGA to achieve attainment with the ozone NAAQS.

BCCA, Dynegy, Equistar, Goodyear, and Lyondell stated that SCR has been successfully designed and applied in many new boilers, heaters, and turbines, achieving up to a 90% reduction of NO_x, but that the experience in application of SCR in retrofit applications of existing combustion units is very limited, and in some combustion applications has never been attempted. BCCA, Equistar, Goodyear, and Lyondell stated that the level of NO_x reductions achieved in retrofit applications can vary due to the non-optimum design and operating conditions of the combustion source, such as flue-gas temperature, fuel composition (e.g., sulfur content, ash, etc.), and furnace configuration. BCCA stated that the application of post-combustion control technology in retrofit applications must be carefully engineered on a case-by-case basis and, in some cases, non-optimum equipment and operating conditions will limit the overall control device effectiveness. BCCA stated that if SCR is applied in under less than optimum design and operation conditions, the NO_x control efficiency will drop below the commission's assumed control efficiency range of 85-90%. BCCA asserted that the commission has not adequately addressed this issue.

The commission agrees that SCR has been successfully demonstrated to achieve a 90% reduction of NO_x from combustion flue gas streams. The commission also agrees that the application of SCR in non-utility retrofit installations has been limited (mostly to refineries in Southern California, Japan, and a few in Europe) and the factors cited will affect the practice of SCR retrofits in HGA. Retrofits can be expected to be harder than new installations. In many applications when SCR is used to comply with cap type programs, a 90% SCR reduction will be the technical choice because it is the most cost effective. In retrofit applications, 90% reduction with SCR may have technical disadvantages that make a lesser degree of reduction more attractive. These more attractive choices will be feasible because of the ability of Tier I controls to reduce the SCR requirement below 90% in most cases. Gas-fired boilers, process heaters, and gas turbines on average can do significantly better than 0.10 lb/MMBtu or 0.15 lb/MMBtu with Tier I retrofits, the levels that would require a 90% flue gas clean up to achieve the ESADs of 0.010 and 0.015 lb/MMBtu. The emissions from recently reported Tier I retrofits on gas-fired boilers and process heaters range between 0.01 and 0.04 lb/MMBtu and toward the higher range appear to be widely feasible. With this range of Tier I controls, the corresponding SCR reduction to comply with the most stringent ESAD of 0.010 lb/MMBtu is between 0% and 75%. Therefore, the average SCR reduction requirement will need to be significantly less than 90%.

Dynegy, Goodyear, and PECO stated with properly designed and operated combustion units using new ultra-low NO_x burners, NO_x reductions in the range of 60-75% are technologically achievable, but that combustion controls cannot meet the proposed 90% reduction, thus requiring SCR.

As noted in the rule proposal preamble, the emission specifications are expected to necessitate SCR on most units. The commission never expected or represented that all emission specifications could be met solely with combustion controls. In fact, in the rule proposal preamble the commission specifically delineated which source categories it expected would need to install post-combustion controls to meet the ESADs. (See the August 25, 2000 issue of the *Texas Register* (25 TexReg 8287-8292 and 25 TexReg 8480-8482).)

TECHNICAL FEASIBILITY--UTILITY BOILERS

BCCA, Entergy, and REI stated that the proposed emission specifications for utility boilers exceed levels commonly achieved in practice or are technically infeasible in wide-scale retrofit applications. BCCA stated that although the proposed rate for utility boilers can be achieved in limited applications, the rate is technically infeasible for many gas-fired boilers. REI stated that the proposed rate for gas-fired utility boilers is more stringent than actual emission rates that have been achieved in practice by the majority of utility gas-fired units in Southern California. REI stated that only four of 13 units identified are currently meeting the proposed rate, based on a review of third quarter 1999 emission data, and that the average NO_x emission rate for these 13 units during this period was 0.015 lb/MMBtu. REI acknowledged that the proposed rate has been achieved by several REI units in California, but stated that inherent differences between these units and the majority of units in HGA will make the proposed rate technically infeasible, or economically unreasonable to achieve. REI stated that a fundamental difference is that the REI California units were originally designed to burn fuel oil as a primary fuel while most HGA units were originally designed to fire exclusively natural gas. REI stated that a unit designed to fire fuel oil will generally have a larger furnace volume and lower burner zone heat release rate than a comparable gas-designed unit, and the higher burner zone heat release rates characteristic of HGA gas-fired units suggest higher baseline NO_x rates, requiring a greater degree of control just to achieve the NO_x emission rates of the Southern California units.

The commission disagrees that the emission standard of 0.010 lb NO_x/MMBtu is technically infeasible for gas-fired utility boilers. In combination, combustion modification and SCR are technically capable of achieving these levels on any gas-fired utility boiler. This level of control may be economically infeasible for particular gas-fired utility boilers, but this is a function of the availability of lower cost competing electric generation technology, such as highly efficient combined cycle turbine power plants and the choices made by the operators. Regardless, because rule compliance is based on a flexible cap, it will not be necessary for each gas-fired boiler to achieve the ESAD. It is true that the gas utility boiler ESAD is more stringent than most of the actual emission rates of the boilers in Southern California. Most of the Southern California boilers are operating under the SCAQMD cap and trade program, RECLAIM, for which the underlying emission specification is the 1991 SCAQMD Rule 1135 emission standard of 0.15 lb NO_x/MWh. This output standard is approximately equal to a heat input standard of 0.015 lb/MMBtu. REI stated that only four of 13 boilers they identified in Southern California are below the ESAD and that the average of the 13 boilers is 0.015 lb NO_x/MMBtu. Four of the 13 boilers REI identified, Ormond Beach 1 and 2, and Mandalay 1 and 2, are the only utility power boilers subject to the VCAPCD emission limit of 0.10 lb/MWh, essentially equal to the 0.010 lb NO_x/MMBtu ESAD. These four boilers are now owned by REI. The data REI supplied in their comments indicate that the MW weighted average emission rate for these four boilers is 0.0085 lb/MMBtu, which is comfortably below the ESAD. Three of these boilers are among the four which operate below the ESAD. The average performance level is clearly a function of compliance with the regulatory standard. The technical feasibility of the gas utility boiler ESAD is supported by the fact that a number of the Southern California boilers are operating below the ESAD. Just as more of the Southern California boilers are operating above the Rule 1135 specification under RECLAIM, the smaller and less frequently operated boilers in HGA will be able to continue to operate above the ESAD under cap and trade compliance.

The smaller furnace volumes of some of the REI gas boilers may make them relatively more difficult to control than some of the California boilers with somewhat larger furnace volumes. This would only mean that with identical controls, the REI boilers would produce somewhat higher levels of NO_x. This would not mean that achieving the ESAD is technically infeasible. Combustion NO_x technology has improved markedly in the years since the Southern California boilers were retrofit. There are new approaches, such as premix of fuel and flue gas to produce a low-NO_x fuel. Under demonstration on a utility unit in Texas, this is currently achieving 0.04 lb/MMBtu, with expectations of even better performance. The accumulation of recent experience makes it evident that even the most difficult gas-fired utility boiler in HGA can be controlled to at least a level of 0.10 lb/MMBtu with combustion controls. It is also clear from the Southern California gas utility boiler SCR experience that SCR is technically feasible of achieving more than a 90% reduction on a gas utility boiler. The average performance of the Southern California utility boilers reported in Table 2-5 of the NESCAUM report is 89.6%, the highest, 94%, using in-duct SCRs. Stand-alone SCR reactors may be designed with higher catalyst volumes and higher control efficiency. The combination of combustion control and SCR is technically capable of achieving the gas utility boiler ESAD.

Concerning gas-fired utility boilers, Entergy stated that the units in the NESCAUM report cited in the rule proposal preamble represented an 85% NO_x reduction (i.e., from 0.20 to 0.030 lb/MMBtu) and asserted that the proposed limits for gas-fired utility boilers are technically infeasible due to the "significant incremental expense of controlling by 95% (to 0.01 lb/MMBtu)."

The commission disagrees with the commenter. The actual performance data referenced in the previous response clearly indicates that the selection of 85% reduction in the NESCAUM cost evaluation spreadsheet was not meant to illustrate the technical limits of SCR. Cost and technical feasibility are two separate issues. Whether or not a control technology or emission specification for a given source category will have a higher (or lower) relative cost than that of any other is not relevant to whether that control technology or emission specification is technically feasible. The commission notes that the ESADs do not represent RACT, which by definition takes cost into account. Instead, the ESADs were developed in order for HGA to achieve attainment with the ozone NAAQS, which is a health-based standard and not a cost-based standard. According to 42 USC, §7409(b), national primary ambient air quality standards are standards which, in the judgment of the administrator of the EPA, are requisite to protect the public health. The criteria for setting the standard is protection of public health, which includes an allowance for an adequate margin of safety.

BCCA and REI stated that the proposed emission specification of 0.030 lb/MMBtu for coal-fired boilers is well below the NO_x emission rate currently achieved in practice by any coal-fired unit in the world and that there is no operating experience at this level, or even approaching this level, to demonstrate that the proposed rate can be achieved or maintained by the affected units in HGA on a continuous basis. REI stated that the primary issues include the lack of SCR experience on Powder River Basin (PRB) coal and the ability to obtain proper mixing of ammonia reagent with dilute concentrations of NO_x while maintaining ammonia slip below two ppm to prevent equipment fouling. REI stated that another obstacle is the ability to obtain completely uniform mixing of the ammonia reagent with NO_x in the flue gas. REI stated that in SCR applications with high inlet NO_x emissions, uniform mixing of ammonia and NO_x is not critical since there is sufficient NO_x to react with any excess ammonia. REI stated that its W. A. Parish coal-fired units are the lowest NO_x emitting units in the United States to be retrofitted with SCR and that as a result the SCR inlet NO_x level will be extremely low (e.g. 20 ppm), making the ammonia-to-NO_x distribution critical. REI stated that while it is paying significant attention to the placement of the ammonia injection grid and the design of the ductwork and static mixers to insure the best possible distribution, maintaining the proper ammonia-to-NO_x distribution under varying operating conditions (i.e. changing load, fuel switches, etc.) may be impossible. REI stated that increasing the ammonia injection rate to improve NO_x reduction will mean exceeding the two ppm ammonia slip target (or ten ppm regulatory limit) unless near perfect mixing is achieved. REI commented that the two ppm target is designed to minimize the formation of ammonium bisulfate and subsequent fouling of downstream equipment (e.g. air heaters) and the contamination of recyclable flyash.

The commission agrees with REI's analysis of the numerous challenges in achieving the design emission specifications for the four coal-fired utility boilers in HGA. The commission has adopted the 0.030 lb/MMBtu ESAD for this category because the reductions are necessary for the SIP and because this level is technically feasible in the commission's analysis, based on the literature and discussions with SCR vendors. REI has awarded a contract for construction of SCRs on its four coal-fired boilers with an emission specification of 0.030 lb NO_x/MMBtu, which supports the commission's view that the technology has the capability to achieve this level.

Enron asserted that the less stringent limit for coal-fired utility boilers, as compared with gas-fired utility boilers, discriminates against these cleaner burning gas-fired units.

Although the coal-fired limit is numerically less stringent, the coal and gas limits require similar degrees of reduction technology to be applied. The coal-fired utility boiler ESAD is probably designed closer to the limits of technical feasibility than the gas-fired utility boiler ESAD.

REI suggested an alternative NO_x emission reduction plan for REI that it said would achieve an 86% NO_x reduction (88% annual NO_x reduction) at a capital cost savings of over $200 million as compared to the proposed emission specifications.

While the commission appreciates the magnitude and cost of the commenter's NO_x reduction efforts which are currently being implemented, the commission adopted the ESADs for EGFs as proposed because anything less would jeopardize the approvability of the attainment plan, and because the proposed ESADs for EGFs are technically feasible, as described elsewhere in this preamble.

Calpine and Enron suggested that the emission specifications for EGFs should be output-based. Calpine and Enron stated that the proposed input-based standards give less efficient units higher allowances than more efficient units, while output-based standards would provide an incentive for less efficient units to optimize their operations, reducing fuel consumption and thereby reducing NO_x emissions.

With existing equipment there is only limited ability to significantly improve operating efficiency. In cases where it is feasible to retrofit to upgrade efficiency, the resulting twin advantages of reduced production costs and reduced emissions for the same production level will be enjoyed under a cap and trade program regardless of whether allowances are based on historical input or output. The existing standards, monitoring systems, and data management programs for utilities are heat-input based. Creating a different basis for a standard would be confusing and would unnecessarily complicate emission monitoring and reporting. In addition, the efficiency penalties associated with the required post-combustion NO_x controls would penalize the units if the standards were expressed on an output basis. The commission believes that output-based standards would provide little benefit for existing units and would needlessly complicate the existing regulatory procedures in place. The commission has made no change in response to the comment.

TECHNICAL FEASIBILITY--AUXILIARY BOILERS

BCCA and REI stated that the proposed emission specification of 0.010 lb/MMBtu for auxiliary boilers is technically infeasible since auxiliary boilers typically operate for extended periods at minimum loads with infrequent operation at high loads. BCCA and REI stated that for most of the operating schedule, flue gas temperatures will be well below conventional SCR operating temperature requirements, thereby preventing effective NO_x reduction.

The commission agrees that SCR is not an appropriate choice for auxiliary boilers because they infrequently operate at high loads. The infrequent operation at high loads means that the cost effectiveness will be extremely poor, regardless of whether SCR is technically infeasible in this application. The commission has added an alternative emission specification as new §117.106(c)(4) for auxiliary boilers, utility boilers, and stationary gas turbines based on Tier I controls. The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for these units with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation. This standard is achievable and is consistent with existing permit limits. As noted later in this preamble in the *DEFINITIONS* section, the commission has revised the definition of auxiliary steam boiler in §117.10(3) to clarify that an auxiliary steam boiler produces steam as a replacement for steam produced by another piece of equipment which is not operating due to planned or unplanned maintenance.

TECHNICAL FEASIBILITY--GAS TURBINES

PECO stated that the use of SCR on simple cycle peaking turbine has not been adequately demonstrated. PECO stated that it knows of only four SCR installations on peaking gas turbines, and that a compressor station in California has requested relief from its emission limits due to difficulties in utilizing SCR. PECO stated that combined cycle units operate at a low exhaust gas temperature and typically operate at a high utilization factor with a low number of startups per run hour, while simple cycle units have a high exhaust gas temperature and typically operate with frequent startups per run hour. PECO stated that high exhaust gas temperatures and frequent thermal cycling contribute to premature failure of a catalyst bed, and that during each startup cycle the SCR's NO_x control efficiency is reduced until it reaches the necessary operating temperature perhaps 15 to 20 minutes into the startup sequence. PECO suggested that NO_x emission specifications for simple cycle gas turbines be set at 0.033 lb/MMBtu and 0.015 lb/MMBtu for combined cycle gas turbines, because SCR has been proven in that application. Solar Turbines stated that "SCR systems may not be technically, operationally, and/or practically feasible for many of the applications as (approximately) 85% of the potentially affected units are in mechanical drive/compressor applications. Historically these applications, due to their high exhaust temperature, are not appropriate applications for an SCR and for which LAER levels have been 8-42 ppm."

The commission agrees with PECO that the adopted ESAD is demonstrated in combined cycle applications. However, the commission also believes that SCR is sufficiently demonstrated in high-temperature applications to justify the ESAD in simple cycle applications. The compressor station in California to which PECO referred had a high-temperature SCR catalyst installed in 1990 which did not perform adequately. Since that time, the company has installed a new SCR catalyst from a different vendor and has met the performance levels required by the source's permit. This vendor indicates that there are a dozen installations of high-temperature SCR on simple cycle turbines in the United States with NO_x control down to several ppm. One packager of SCR systems has said that there are many high-temperature SCR orders being placed for simple cycle utility operation in summer 2001. According to this packager, the high temperatures and frequent thermal cycling are expected to shorten the life of the catalysts to two or three years, based on 2000 hours per year of operation. Although catalyst replacement cost may be higher relative to a conventional SCR, the peaking turbines need to be well controlled because they operate during periods of peak electric demand, mostly the hot summer days which are conducive to ozone formation. The turbines with the highest exhaust temperatures may add dilution air or water to lower the exhaust temperature to improve SCR performance. Catalytic combustion may become a technology alternative to SCR in the 2004-2005 time frame for the type of gas turbines that PECO has proposed to construct. The commission has not changed the ESAD in response to these comments.

BCCA and REI stated that the proposed emission specification of 0.015 lb/MMBtu (approximately four ppm) is well below the levels included in SCAQMD Rule 1134 of approximately 9-15 ppm and approaches LAER for new installations. BCCA stated that it reviewed worldwide retrofit experience for gas turbines and that it found no equipment designed for and meeting the proposed emission standards. BCCA asserted that the commission failed to take this worldwide lack of experience into account when setting the proposed emission limits. BCCA and Dynegy noted that the current limit for gas turbines in HGA is 42 ppm NO_x as of December 31, 1999. BCCA and Dynegy stated that there are four types of NO_x control technologies for gas turbines: wet combustion controls (steam or water) that can get many models down below 42 ppm; combustion hardware controls (known as dry low-NO_x burners (DLN) for most models) that are available for many models to get the NO_x ppm down to the mid-twenties or low-teens; SCR to get the NO_x ppm down to below the ten ppm level; and a combination of SCR and combustion controls to possibly achieve a NO_x ppm in the mid-single digits.

The adopted HGA retrofit standards for gas turbines appear to be the most stringent retrofit standards in the world. Because of this, very few retrofits have been designed to meet these levels. The adopted ESAD is below the levels in SCAQMD Rule 1134 because it is technically feasible to meet a more stringent standard. Specifically, the commission is aware of several units which are operating below the adopted ESAD. The 32 MW gas turbine at the Federal Plant in Vernon, California has been retrofitted with a NO_x adsorber catalyst to achieve emissions of two ppm NO_x, which is 50% lower than the adopted turbine ESAD. Other gas turbines have included the Tier III combination of combustion modifications and SCR controls in the original design and are operating below the adopted ESAD. An example is the 102 MW combined cycle Siemens V84.2 gas turbine at the Sacramento Power (Campbell Soup) plant in Sacramento County, California. It has been operating at three ppmv NO_x since October, 1997. In addition, since July 1999, the commission has received permit applications for at least 25 new gas turbines, in projects representing more than 6,800 MW of new electric capacity, all to be located in HGA and to operate below the 0.015 lb/MMBtu ESAD for gas turbines, using Tier III controls.

The commission took into account the capabilities of the various technologies when setting the ESAD for turbines. Tier I combustion modifications have been applied to most of the gas turbines above ten MW in HGA because of the 42 ppmv, 15% oxygen (0.15 lb/MMBtu) NO_x RACT limit of §117.205. The Tier I technologies, DLN and steam or water injection have been used to meet this limit. For units just meeting the RACT limit, Tier II flue gas cleanup would require a 90% additional reduction. Tier I retrofits are capable of between 9 and 15 ppmv (0.033-0.050 lb/MMBtu) with DLN for some models, and 25 ppm (0.09 lb/MMBtu) with either DLN or wet injection for almost all of the others. With these maximum Tier I controls, the resulting flue gas cleanup reduction requirement would range between 54% and 83%. The BCCA surveyed a number of firms involved with gas turbine SCR projects and their summary indicated that among hundreds of gas turbine SCR applications, there were about one dozen retrofits. In many applications when SCR is used to comply with cap type programs, a 90% SCR reduction is the technical choice because it is the most cost effective. In retrofit applications, 90% reduction with SCR may have technical disadvantages that make a lesser degree of reduction more attractive. These more attractive choices will be feasible because of the ability of Tier I controls to reduce the SCR requirement below 90% in most cases. The summary did not indicate levels of reduction for these SCR retrofits but, due to the cost of installing SCR, it would be expected that few would have been designed for less than 70%. However, depending on the regulations in effect and the compliance strategy used by the owner, lower efficiencies may simply reflect design for compliance with the regulatory limit rather than the capability of the technology in the particular application. The NO_x reduction obtainable with SCR is a design parameter, and it can be expected that a number of retrofits will be designed for at least 90% reduction in HGA.

BCCA stated that two of the five major worldwide providers of gas turbines have never performed a retrofit application of post-combustion control technology.

The gas turbines in HGA were primarily built by three companies, although four other manufacturers have at least one turbine operating in the area. Turbine manufacturers' retrofits tend to apply to the turbine itself, and each of the three primary builders of the HGA gas turbines have some experience with retrofit of combustion modifications, water or steam injection and dry low-NO_x burners. Post-combustion control technology, such as SCR, would typically be provided by turn-key suppliers of SCR systems packages, who have some experience with gas turbine retrofits as indicated in the previous response.

BCCA noted that gas turbines can be found in utility plants, industrial plants, and remote pipeline transmission sites, and stated that each location, and in many cases each machine, has its own unique design and operating conditions that need to be considered when determining the feasibility of a particular NO_x reduction technology. BCCA stated that gas turbines in HGA vary by manufacturer and model, and the manufacturer must develop the technology for each specific engine model. BCCA stated that as an example, steam and/or water and low-NO_x combustion hardware is not currently available from some manufacturers, narrowing the owners' technology options. BCCA and REI stated that the ESAD for gas turbines cannot be reasonably achieved in retrofit applications where after-market water injection or DLN firing systems are not available, where space constraints impact SCR design, or where flue gas temperatures preclude SCR altogether. Solar expressed similar concerns and provided a table attachment with their comments which summarized availability and existing operation of applications of DLN, water, and SCR controls on their turbines.

Turbine manufacturers indicated during the development of the currently applicable 42 ppm NO_x RACT limit that combustion modifications, with either after-market water injection or DLN, were feasible on all models of gas turbines above ten MW known to be in operation in HGA. Water or steam injection has widespread retrofit applicability, in contrast to the limited applicability of retrofit DLN, the feasibility of which is dependent on the design features of specific models. Water injection may be provided by an aftermarket supplier, but the availability of DLN depends on the original turbine manufacturer. The costs for design or installation of water or steam injection controls for a few of the older turbine models in HGA may have caused alternative RACT compliance strategies to be used. These issues relate to cost rather than technical feasibility. In Solar's table, either water injection or DLN are available as Tier I controls on each model line, except for the smallest line, the Saturn 10s. The Tier II control, SCR, is listed as an option for each model type. As indicated in a response following this one, the commission has adjusted the ESAD in response to the information received that Tier I controls are not feasible for the Saturn 10s. Space constraints will affect SCR design, but the relocation of the heat recovery section to install a conventional temperature SCR is a demonstrated approach and therefore technically feasible. In addition, low-temperature SCR is capable of reducing or eliminating the need to relocate heat recovery equipment. Examples of low-temperature SCR providing between 90% and 95% reduction are listed in *Low-temperature SCR Expedites Plant Retrofits for NO_x Reduction* (Gas Turbine World, July/August 1997 issue). One of the examples is in HGA, a 90% reduction on a 325 degrees Fahrenheit exhaust stream from an Allison 501-KB5 gas turbine located in Pasadena, which is part of the HGA ozone nonattainment area. With regard to flue gas temperatures precluding SCR altogether, as discussed in the first response in this section, the commission believes that high-temperature SCR is technically feasible for simple cycle gas turbine exhausts.

BCCA, GPA, and Kinder Morgan stated that the use of efficient low-NO_x combustion technologies should be applied on gas turbines to achieve a 60 to 75% reduction to a 42 to 25 ppm NO_x emission levels, but without use of SCR. TCC suggested that small turbines should only be required to make burner improvements. Enterprise stated that it does not have the option to replace its 36 gas turbines with a smaller number of larger units since each installation is unique for its turbine compressor or turbine generator package. Enterprise suggested that NO_x emission specifications for gas turbines be set at 0.030 lb/MMBtu (approximately nine ppm) for large turbines and 0.15 lb/MMBtu (approximately 42 ppm) for small turbines.

The commenters are recommending Tier I control levels for their gas turbines. The gas turbines are the second largest category of point sources in HGA, and Tier III standards are required for a successful attainment demonstration. The previously referenced plant in Pasadena which is achieving a 90% reduction using low-temperature SCR on an Allison 501-KB5 gas turbine indicates both the technical feasibility and economically reasonableness of Tier II controls for small gas turbines. The commission has made no change in response to the comments.

Kinder Morgan expressed concerns that application of SCR to gas turbines in gas transmission service would encounter the load following problems experienced on lean-burn IC engines in similar gas transmission service.

The commission believes that the current generation of SCR operating controls designed for load following applications will address Kinder Morgan's concerns. Conversion to electric motors is also a compliance option.

Kinder Morgan stated that the commission should reconsider the emission specifications for gas turbines less than 1.0 MW and establish emission specifications based on existing, proven combustion modification technology. Solar said that water injection is not available on their 1,000-1,300 hp gas turbines.

Solar offers neither DLN or water injection on their less than 1.0 MW gas turbines, the older Saturns. They do not currently offer water injection on the Saturns as a result of an unsuccessful application in California. In response to information provided by Solar that the water injection problem with the Saturns relates to physical limitations of the small combustor, the commission modified the ESAD for existing turbines below 1.0 MW (1,340 hp) to reflect the application of Tier II controls. The adopted ESAD for gas turbines with a rating below 1.0 MW and placed into service on or before December 31, 2000 is 0.15 lb NO_x/MMBtu, which is very similar to the 0.5 g/hp-hr limit for lean-burn gas-fired IC engines. This limit could be met by SCR and would leave water injection as a possibility if the technical issues can be overcome.

BCCA, Kinder Morgan, Solar Turbines, and TCC commented that small gas turbines (less than 10-20 MW) are often used with duct burners to generate thermal heat recovery efficiently. TCC stated that many small turbines, some with duct burners, are involved with heat recovery so they cannot efficiently be replaced with electrically driven turbines, and that if heat input had to be drawn from another source, then that source will emit additional NO_x.

The basis for the gas turbine ESAD is not replacement with electric drive, although this approach could be used to comply for some mechanical drive applications. Sources with heat recovery can retrofit SCR in the conventional temperature zone for SCR or apply low-temperature SCR at the back end.

BCCA stated that requiring a 90% reduction from the current 42 ppm NO_x level, which it asserted can only be achieved today with SCR, skips the DLN option. TCC said that the commission should encourage the use of burner improvements to control small stationary gas turbines. Solar Turbines stated that some older turbines cannot be retrofitted with DLN systems. Solar provided an inventory of its machines operating in HGA which indicated DLN is not feasible on half of them, and of those for which it is technically feasible, 34% would require power uprating with significant costs, 11% are using DLN, and 5% are retrofittable with DLN without an upgrade to increase the power rating.

The commission agrees that DLN, with varying capabilities between 9-42 ppmv, cannot achieve a 90% reduction from the current 42 ppm level. Contrary to being a skipped option, the DLN retrofit option was used on some units to comply with the 42 ppm NO_x RACT emission specification. Solar's comment indicates that DLN may well be attractive for a few additional machines in providing the combustion modification step, but flue gas cleanup would still be required to meet the adopted ESAD. The potential for increased availability of DLN is limited because the original turbine manufacturer faces high development costs based on unique design features of specific models, of which there may be few in operation and even fewer subject to stringent emission specifications. Even if a new DLN retrofit design were successfully engineered, it would have to compete with more effective retrofit technologies in the market place. NO_x control technologies in operation today that are more effective than DLN include high-temperature, conventional-temperature, and low-temperature SCR, NO_x adsorber catalyst, and catalytic combustion.

BCCA stated that the combustion control technology for many models of gas turbines is still being improved and new technologies, such as catalytic burners, are being developed but are not yet in commercial application. BCCA stated that catalytic burners, an emerging technology for new gas turbines, have the potential to reduce NO_x levels as low as SCR systems with no ammonia slip, and will likely be significantly lower in cost. BCCA also stated that downtime for retrofits will be less compared to an SCR installation, operations and maintenance costs are also expected to be much lower, and there will be no additional back pressure and resultant efficiency loss typically experienced with SCR retrofits. BCCA asserted that the proposed emission specifications for turbines may preclude the use of emerging combustion technologies that may achieve SCR-like NO_x reduction performance levels without the potential environmental impact of ammonia. Dynegy commented similarly, citing more specifically the possibility of avoided risk from transport and storage of ammonia, spent catalyst, and increased carbon dioxide (CO_2) emissions. TCC said that the commission should encourage the use of burner improvements to control small stationary gas turbines.

Catalytic combustion for gas turbines is an attractive technology for the reasons cited by the commenters. There are a number of time consuming steps necessary to implement catalytic burners, including obtaining development capital for burner design for specific turbines, engineering, pilot testing, and demonstration in commercial operation. These steps must be repeated for each type of turbine burner. Several years of lead time are necessary before commercial operation can begin. Because of these steps, it appears that catalytic combustors will be first applied to new rather than existing gas turbines and only a few gas turbines will operate with this technology by 2005. Nonetheless, stringent gas turbine emission standards such as contained in this rulemaking provide a strong impetus to commercialize catalytic burners. The structure of the adopted rule also provides incentives to innovative technology. First, the market approach values overcompliance with the standards. Second, emission compliance is annual for most sources. Higher emissions which may occur with a new technology because of start-up bugs likely occur for a short time. Annual averaging reduces the significance of short time values. Innovative technologies such as catalytic burners which may offer performance better than the standard can particularly benefit from the market approach and long term averaging.

TECHNICAL FEASIBILITY--ICI BOILERS AND PROCESS HEATERS

BCCA stated that the proposed emission reductions for industrial boilers go well beyond current BACT for new sources and approach or meet the most stringent emission standards envisioned for new sources, LAER. BCCA stated that in most cases, the proposed emission standards for ICI facilities exceed the SCAQMD emission limitations.

The ESADs for large boilers go beyond the commission's current BACT. Currently, the NO_x BACT guidelines, which apply statewide, are set at levels achievable with Tier I, or combustion controls. One notable exception is the guideline for large combined cycle gas turbines, which is based on combustion modifications and flue gas cleanup. NO_x controls, including combustion controls, have rapidly improved in capability recently, and appear to be continuing to do so. Recent permits issued by the commission have set lower NO_x levels than some of the written BACT guidelines which may not reflect current capabilities of Tier I controls.

In the SCAQMD, new boilers are being permitted for NO_x levels essentially equivalent to the lowest boiler ESAD of 0.010 lb/MMBtu (eight parts per million by volume, dry basis (ppmvd) at 3% oxygen, annual average). The SCAQMD BACT website at http://www.aqmd.gov/bact/AQMD_BACT_Determinations.htm includes information on three boilers in sizes of 110, 78.6 and 48.6 MMBtu/hr. They are permitted at a limit of nine ppmvd at 3% oxygen, on a 15-minute average compliance time. For the boilers between 40 and 100 MMBtu/hr, nine ppm is 25% lower numerically than the ESAD of 0.015 lb/MMBtu (12 ppmvd at 3% oxygen). The 15-minute average of the SCAQMD permits represents effectively an even greater difference than the annual ESAD. Even for the 110 MMBtu/hr boiler, nine ppmvd on a 15-minute average is at least as stringent as the corresponding eight ppmvd ESAD, considering the difference in effective stringency between a 15-minute and annual average compliance period. The commission notes that these permit limits are based on Tier I controls, ultralow-NO_x burner technology, rather than Tier II flue gas cleanup, or the combination, Tier III.

In the SCAQMD, new process heaters are being designed for lower NO_x levels than the lowest process heater ESAD of 0.010 lb/MMBtu (eight ppmvd at 3% oxygen). The SCAQMD BACT website at http://www.aqmd.gov/bact/AQMD_BACT_Determinations.htm includes information on the following process heaters and limits: 460 MMBtu/hr hydrogen reformer furnace, seven ppmvd at 3% oxygen; 764 MMBtu/hr hydrogen reformer furnace, five ppmvd at 3% oxygen; 653 MMBtu/hr hydrogen reformer furnace, five ppmvd at 3% oxygen; 50 MMBtu/hr refinery heater, seven ppmvd at 3% oxygen. The refinery heater is permitted 42% lower than the corresponding process heater ESAD of 0.015 lb/MMBtu (12 ppmvd at 3% oxygen). The controls are Tier III, using low-NO_x burners and SCR for flue gas treatment. The SCAQMD heater permits set a three-hour averaging period, significantly more stringent than the annual average of the ESADs.

BCCA stated that it reviewed worldwide retrofit experience for ICI boilers, process heaters, and furnaces (general application and steam cracking furnaces), and that it found no equipment designed for and meeting the proposed emission standards. BCCA asserted that the commission failed to take this worldwide lack of experience into account when setting the proposed emission limits.

There are many ICI boilers and process heaters in a wide range of sizes, retrofit with no more than combustion modification controls, operating below the 0.036 lb/MMBtu ESAD (30 ppmv) for boilers and heaters less than 40 MMBtu/hr. Most districts in California set boiler and process heater retrofit requirements at this level for ICI boilers and process heaters above 5 MMBtu/hr, whereas SCAQMD and VCAPCD set the applicability levels at 2 MMBtu/hr and higher. The 30 ppmv NO_x limit has proved to be met by combustion modifications only.

There are fewer ICI boilers and process heaters above 40 MMBtu/hr in size which are operating at the 0.010 and 0.015 lb/MMBtu ESADs (8 and 12 ppmv, respectively) for equipment larger than 40 MMBtu/hr. This is because the most stringent NO_x retrofit standards anywhere, set under the RECLAIM program in the SCAQMD in 1993, are based on the 1988 SCAQMD Rule 1109 limit of 0.030 lb NO_x/MMBtu for refinery heaters and boilers. At the Los Angeles refineries, Rule 1109 and RECLAIM have resulted in relatively fewer of the larger sizes of ICI boilers and process heaters controlled to levels near the HGA specifications, with a greater number of smaller or less frequently operated units controlled to less stringent specifications. Nonetheless, at least nine refinery heaters between 60 and 931 MMBtu/hr have been retrofitted and are currently achieving emissions ranging from 0.004 to 0.011 lb/MMBtu, with a heat input weighted average emission rate of 0.006 lb/MMBtu. The average rate is substantially below the ESADs of 0.010 and 0.015 lb/MMBtu.

The RECLAIM program uses a declining cap which only in 2000 caused emission credits to become tight and valuable; the allocations will be reduced at least two more years, so additional reductions are necessary. The largest refinery boilers in HGA overlap in size with the smallest utility boilers. The following utility boilers in Southern California are operating below the 0.010 ESAD using Tier III controls: El Segundo 4, 0.008 lb/MMBtu; Mandalay 1 and 2; 0.007 lb/MMBtu; Ormond Beach 2, 0.007 lb/MMBtu. The 320 MW El Segundo 4 is achieving levels significantly below the Rule 1135 regulatory driver of 0.015 lb NO_x/MMBtu in Southern California because the emission trading program rewards overcompliance. Another unit, the 110 MW Encina 2, is operating at 0.014 lb NO_x/MMBtu.

The annual NO_x emission rate data for these and other utility boilers operating in Southern California with Tier III controls can be found by inspecting the EPA acid rain data base at http://www.epa.gov/acidrain/score98/es1998.htm.

The present relative scarcity of retrofit applications operating near the adopted HGA specifications is a function of regulatory standards, rather than technical feasibility. Regulations set emission levels, and the HGA NO_x specifications are lower than the Los Angeles standards in several categories. The rules underlying Los Angeles' current point source NO_x retrofit specifications were adopted more than ten years ago and until now, only a few areas, such as VCAPCD, have set lower retrofit specifications. The progressive development and application of technology in Los Angeles and elsewhere in the world to existing and new equipment, achieving single digit NO_x ppm, demonstrates that the Houston NO_x emission specifications are technically feasible.

KTC, TCC, and an individual commented on the proposed NO_x emission specification for boilers and process heaters in §117.206(c), and stated that boilers or process heaters which utilize process waste gas containing chemical-bound nitrogen as a source of fuel or combustion air should receive a multiplier for compliance with the emission specifications for a variety of reasons. KTC and TCC stated that utilizing process waste gas as fuel in boilers provides both useful extraction of energy, as well as pollution control. KTC and TCC stated that because NO_x limits may not be achieved while burning waste gas, industrial sources will make large capital expenditures for flares and actually result in an increase in NO_x emissions. KTC and TCC stated that the new flares will burn fuel, creating NO_x, and the boilers will have to use more natural gas to replace the lost waste gas fuel. KTC and TCC stated that process waste gas compounds containing chemical-bound nitrogen may have a high heating value, which has the potential to produce a higher flame temperature than materials that have a lower organic content, thus reducing the chance of meeting proposed NO_x emission specifications. KTC and TCC stated that catalytic reduction of NO_x is not practical as a pollution control solution because of the variability of process waste gas and the likelihood of fouling or poisoning of the catalyst. KTC stated that vendor claim that a 75% NO_x reduction can be achieved with combustion modifications such as low-NO_x burners and FGR, but that two of its boilers utilize low-NO_x burner and FGR, yet do not meet the proposed limits.

The commenters have noted that the rules as proposed create some incentive for circumvention by redirecting dirty fuel streams to flares or other units for which an ESAD has not been established. To prevent such circumvention from resulting in an increase in emissions at non-ESAD units, the commission has added a new §117.206(h) which prohibits the owner or operator of units which utilize liquid or gaseous streams containing chemical-bound nitrogen as a source of fuel or combustion air from circumventing the emission reduction requirements by directing these streams to flares or other units which are not subject to an ESAD in §117.206(c), unless the unit which receives the chemical-bound nitrogen stream is opted into the Chapter 101 mass emissions cap and trade program, and NO_x emissions from this opt-in unit are determined using a CEMS or PEMS which meets the requirements of §117.213(e) or (f), or through stack testing which meets the requirements of §117.211(e).

TECO commented that it operates two "District Energy Plants" which furnish steam and chilled water to a variety of medical buildings, including four gas-fired boilers rated at over 100 MMBtu/hr heat input which would be subject to the proposed 0.010 lb/MMBtu emission specification of §117.206(c)(1)(A). TECO stated that future growth could result in the building owners installing individual boilers rated at less than 40 MMBtu/hr, which would be limited to 0.036 lb/MMBtu, and that the boilers would produce less than ten tpy and therefore would not be subject to the proposed Chapter 101 mass emissions cap and trade program. TECO also noted that these smaller boilers would not have to install CEMS. TECO suggested setting a NO_x emission specification of 0.030 lb/MMBtu for "District Energy Plants" with gas-fired boilers rated at over 100 MMBtu/hr heat input and stated that this would be more cost-effective than meeting the proposed 0.010 lb/MMBtu emission specification, but would result in greater emission reductions compared to multiple smaller boilers.

The 0.010 lb/MMBtu emission specification may be achievable with Tier I controls for the single burner boilers above 100 MMBtu/hr that TECO operates. The emission specification is appropriate for natural gas fired boilers in this size range. However, TECO raises a valid point about the possibility of adding additional smaller boilers under separate control at different sites, at the higher 0.036 lb/MMBtu ESAD. The net result would be higher emissions than if TECO were to provide this expanded capacity. The medical centers are projected to grow, and the cap would effectively prevent TECO from providing the additional chilled water requirements to accommodate this growth at the lower emission rates from their larger boilers. One option would be to provide incentives for larger, cleaner facilities by allowing a District Energy Plant to add to its activity level when a firm contract for energy is arrived at from a new player who wouldn't otherwise be subject to the cap and trade program. However, the commission believes it may be more appropriate to address any potential increase in emissions from small sources outside the cap by targeting those sources directly (for example, by lowering the threshold for the cap and trade program) in potential future rulemaking.

BP, Equistar, Lyondell, and TCC suggested that the proposed emission specification for process heaters in §117.206(c)(8) should be revised to add a separate emission rate for pyrolysis reactors (ethylene cracking furnaces) because they are unaware of technology which would enable pyrolysis reactors to meet a 0.010 lb NO_x/MMBtu emission specification. BCCA stated that there has been no retrofit post-combustion control application on ethylene pyrolysis furnaces anywhere in the world. Equistar, Lyondell, and TCC stated that a pyrolysis reactor is a combustion device where ethylene and propylene are produced from feed stocks such as ethane, propane, butane and naphtha, with highly endothermic thermal cracking reactions that require significant heat input to start and complete the reactions. BP, Equistar, Lyondell, and TCC stated that a pyrolysis reactor is different from a typical process heater because of the following: higher firebox temperature, flame temperature (2,200-2,300 degrees Fahrenheit), and heat flux (heat transfer per unit of area, Btu/(hour)(square foot)), as flame firebox temperature increases the NO_x production increases; high hydrogen content of olefins plant fuel gas, which further increases flame temperature; highly endothermic reaction that requires higher heat input with high-temperature radiant tubes/coil; high-temperature radiant section-pyrolysis cracking reaction occurs inside radiant tubes with no catalyst; smaller diameter radiant tubes to achieve a shorter residence time (less than one second); coke formed during pyrolysis reaction fouls the radiant tubes that requires periodic cleaning; convection section-highly integrated energy recovery system, higher energy efficiency (90-94%); and multi-stream energy recovery achieved (feed pre-heat, boiler feed water, steam superheating, and mixed feed superheating). Equistar, Lyondell, and TCC also stated that pyrolysis reactor conditions vary more widely than process heater conditions; that different feedstocks and different market conditions affecting optimal reaction severity require different cracking temperatures; and that the complex heat distribution requirements have thus far defeated efforts to reduce NO_x dramatically via ultra low-NO_x burners.

The commission agrees that the ethylene furnaces present a challenge to control, particularly with regard to Tier I controls, because of the factors cited by the commenters. Ultra low-NO_x burners on recently constructed ethylene furnaces, including ones in HGA, are capable of 0.050-0.060 lb/MMBtu, which is considerably higher than what is achievable on boilers and process heaters in less strenuous applications. Nonetheless, based on permitting experience and discussions with burner vendors, the commission believes that combustion modifications are capable of achieving at least 0.10 lb/MMBtu on the existing ethylene furnaces in HGA. The adopted ESAD of 0.010 lb/MMBtu places a demand on burners and combustion modification to achieve at least 0.10 lb/MMBtu; SCR is capable of at least 90% reduction below this. The recently permitted furnaces in HGA achieve significantly better than 0.10 lb/MMBtu with combustion modifications, allowing either a less efficient SCR, or more likely, overcompliance for generation of emission credits. The commission is aware of low-temperature SCR on ethylene furnaces in Germany and the Netherlands; the installation in the Netherlands is a retrofit application achieving a 91% NO_x reduction. Low-temperature SCR, which is installed at the back end of the furnace, may be an attractive option for many of these units because of the clean fuels burned and the complexity of the heat recovery sections.

TECHNICAL FEASIBILITY--FCCU

BCCA stated that it reviewed worldwide retrofit experience for FCCUs, and that it found no equipment designed for and meeting the proposed emission standards. BCCA asserted that the commission failed to take this worldwide lack of experience into account when setting the proposed emission limits. BCCA stated that there is only one commercial application of post-combustion control technology in the United States on a refinery FCCU (one that has just started up in California). BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for FCCUs. BCCA and TxOGA requested that the commission provide the technical justification for the proposed emission specifications for FCCUs. BCCA stated that there is no long-term demonstrated commercial experience in the world to indicate this type of retrofit NO_x standard is achievable for all FCCUs in HGA. BP stated that the proposed emission specification for FCCUs in §117.206(c)(2), ten ppmv at 0.0% O_2 (dry basis), would represent a 95% reduction using SCR at their location. BP stated that they are not aware of technology which would meet this standard. BP stated that some FCCUs with hydrotreated feed typically have an uncontrolled NO_x level of 200 ppmv, and therefore "*may* be able to achieve a 90% reduction across the SCR" to reach 20 ppmv. (BP's emphasis supplied.) BP stated that FCCUs with non-hydrotreated feed may more typically have an uncontrolled NO_x level of 300-400 ppmv, and therefore could achieve 30-40 ppmv based upon a 90% reduction across the SCR. BP considered these units more similar to coal-fired boilers (0.030 lb NO_x/MMBtu) rather than process heaters (0.010 lb NO_x/MMBtu) since the catalyst "coke-burn" in a FCCU is somewhat comparable to coal-firing in a boiler. BP stated that installation of SCR on an FCCU presents unique challenges, such as potential for flow reversal or other nonroutine operating conditions such as high temperature at the SCR catalyst or excessive carryover of FCCU catalyst into the flue gas stream. Consequently, BP suggested that the commission allow the facility to permit start-up emissions or accept a demonstration that certain start-up emissions are unavoidable. Phillips 66, TxOGA, and Valero expressed concerns similar to those of BP and stated additionally that sulfur dioxide scrubbers will be required to protect SCR catalysts from poisoning. Valero stated that its refinery does not employ wet gas scrubber technology. Valero suggested that the FCCU NO_x emission specification for refiners that have already committed to install wet gas scrubbers be set at levels consistent with the wet gas scrubbing technology committed to be installed. Phillis 66 and TxOGA also stated that flue gas temperature conditioning with duct burners, an additional NO_x source, will be necessary to make the system viable.

The commission staff used NO_x emission information submitted by refinery representatives to calculate an average concentration of 100 ppm and therefore a 90% reduction would be achieved by an ESAD of ten ppmv. However, there wasn't sufficient analysis of weighted flow rates, so the commission has reevaluated the average concentration using available data and determined a tpd-weighted average of 125 ppmv. Therefore, commission modified the limit to either 13 ppmv or 90% reduction measured either by an upstream/downstream CEMS, or from baseline data approved by the commission. As part of this effort, the commission has accelerated the timetable for installing NO_x CEMS on the FCCU to June 30, 2001 for any FCCU which uses the baseline data approach. This would be necessary to consider actual long term operating data in conjunction with the 1997 emission inventory data used in the SIP, in time for setting the emission allocations. The Tier I combustion modifications that may be available to reduce NO_x include: managing nitrogen in the feedstock, low oxygen operation, or use of low-NO_x combustion promoters or NO_x removal additives. Low-NO_x promoters and NO_x reduction additives each have been shown to reduce NO_x emissions by more than 50% in commercial operation. With regard to Tier II technology, SCR is in commercial operation on FCCUs on a significant number of units worldwide, including the United States, Japan and Europe (at least seven in Japan, one in the Netherlands, and ExxonMobil in Torrance, California). The ExxonMobil Torrance refinery SCR was designed for a 90% removal. For the FCCUs which use wet scrubbers, low-temperature or phosphatic oxidation may be a viable technology alternative to SCR which would utilize the existing scrubber and avoid moving major equipment or reheating flue gas to achieve the necessary temperature window for SCR. The combination of demonstrated removal efficiencies from both Tier I and Tier II controls and the modification of the FCCU ESAD to either a concentration limit or a percent reduction ensure that this standard is technically feasible.

TECHNICAL FEASIBILITY--BIF UNITS

Solutia, TCC, and Union Carbide stated that the proposed NO_x emission specification of 0.015 lb/MMBtu for BIF units in §117.206(c)(3) is not technically achievable. An individual stated that nearly all liquid-fueled units are equipped with wet scrubbers, and that moisture, particulate, metals, sulfur, and chloride cause significant problems with SCR or selective non-catalytic reduction (SNCR). The individual suggested that the emission specification for units with wet scrubbers should be an 80% reduction. TCC and Union Carbide stated that post-combustion controls will be difficult to maintain due to the inorganics in the fuel, which can deactivate or plug SCR catalysts.

The commission considered the waste streams in the HGA BIFs in response to these comments and agrees with the commenters that certain of the units have "dirty" exhaust streams, primarily with sulfur and chlorides, and a few with some metals and other inorganics. Liquid firing is almost a prerequisite for classification as a BIF, because gaseous materials are not regulated as hazardous waste under Resource Conservation and Recovery Act (RCRA) regulations. The largest BIFs, those rated above 100 MMBtu/hr heat input, are industrial boilers burning liquid hydrocarbon wastes without high levels of inorganic "dirty" materials and without wet scrubbers. The use of SCR would not be a problem for the largest BIF boilers because hydrocarbon wastes combusted in these boilers produce exhaust products essentially indistinguishable from any hydrocarbon fuel. The commission adopts the 0.015 ppm ESAD for BIFs, if rated greater than 100 MMBtu/hr heat input, because these boilers combust hydrocarbon wastes which do not threaten to reduce the effectiveness of SCR as the flue gas cleanup application.

The units with "dirty" exhaust streams use wet scrubbers to remove acid gases and some of the other inorganics. Considering the "dirty" streams, SCR has been employed in a few high sulfur fuel oil applications, but the inorganic compounds present in the exhaust degrade the performance more rapidly than cleaner fuels. The commission disagrees with the comment that SNCR will be adversely affected by these inorganics, because there is no catalyst to degrade and the NO_x reductions are favored in the high-temperature zone where SNCR is located. However, SNCR is typically capable of reductions in the 50-60% range, not high enough to achieve the ESAD.

In addition to SCR, there are two new oxidation technologies for NO_x reduction which are not yet fully demonstrated. One technology has some demonstration in commercial practice, and the other appears to be moving rapidly to commercial demonstration. One of these, low-temperature oxidation, injects ozone as the oxidant to form dinitrogen pentoxide (N_2O_5), which is then removed in a wet scrubber. Because N_2O_5 is highly soluble in water, this process produced NO_x removal efficiencies in the 99% range (i.e., achieved reductions to two ppm NO_x) when demonstrated commercially on a natural gas-fired boiler in Los Angeles which began operation in October 1996. The other process injects elemental phosphorus as the oxidant to form nitrogen dioxide (NO_2), which is also removed in a wet scrubber. The phosphorus based process is anticipated to produce at least 75% reduction in a commercial demonstration on a high sulfur coal-fired utility boiler in Ohio, scheduled for startup in the first half of 2001. The boiler retrofit project is under the financial sponsorship of the owner, a large electric utility.

The commission believes that the exhaust streams from the BIFs with higher levels of inorganics will pose greater technical challenges than the more common, cleaner streams. SCR removal efficiency of 80% would be a more reasonable design goal for dirty fuel streams. The BIF units with existing scrubbers would logically be good candidates for NO_x scrubber technology because of the potential avoidance of capital expenditure for a new scrubber as well as the operational experience in place with the scrubbers. The oxidation technologies appear capable of the 90% reductions envisioned by the proposed BIF ESAD. However, developing technologies, like NO_x oxidation, are likely to have more unforeseen practical challenges compared to established technologies and these challenges can compromise performance goals. Because of the concerns raised by the commenters about inorganic materials in the exhaust streams, the commission has modified the ESAD for the BIFs rated less than

100 MMBtu/hr heat input. The adopted ESAD for these units is either an 80% reduction from baseline, or 0.030 lb/MMBtu.

Union Carbide stated that some combustion controls will compromise the intended purpose of BIF units (i.e., disposal of hazardous wastes). TCC and Union Carbide stated that optimization of the firebox for NO_x control may actually begin to coat the catalyst sites and reduce the overall effectiveness of the SCR. TCC and Union Carbide stated that all BIF units are operated with excess oxygen and high residence times and/or high temperatures to ensure complete destruction of organics, and all of these operating techniques are contrary to NO_x formation control technology. An individual stated that there is no commercially-available low-NO_x burner for liquid fuels and that the proposed emission specification in §117.206(c)(3) should not apply to liquid-fueled BIF units.

As noted in the rule proposal preamble, the emission specifications are expected to necessitate flue gas controls on affected BIF units and RCRA incinerators. The commission never intended or expected combustion controls to be used on BIF units and RCRA incinerators to meet the emission specifications. The basis for the higher ESAD for certain BIF units compared to boilers and heaters (those rated above 100 MMBtu/hr) was that combustion controls could compromise the intended purpose of BIF units. (See the August 25, 2000 issue of the *Texas Register* (25 TexReg 8287-8292 and 25 TexReg 8480-8482).) Although combustion controls were presumed not to be part of the compliance strategy for purposes of rule development, combustion controls are not precluded from being used in practice for compliance with the adopted ESAD for BIFs. Some of the large industrial boilers which are regulated as BIFs may be able to significantly reduce NO_x emissions from gas firing with combustion modifications while retaining the conditions necessary for proper destruction efficiency while firing liquid hazardous waste. The commission made no changes to the ESADs in response to these comments.

TCC stated that combustion controls for NO_x typically increase the amount of CO generation, but that federal BIF regulations are written to minimize the CO generation since it is an early indicator of the destruction efficiency of the constituents of the hazardous waste used as fuel. TCC stated that 40 CFR 266.102(e)(2)(ii)(A) and 40 CFR 266.104(b) specially call out for a CO limit of 100 ppmv at 7.0% oxygen (dry basis). TCC stated that this is one third of the limit allowed in §117.206(e)(1) when converted to the same conditions. TCC stated that while post combustion controls can also remove CO in addition to NO_x, a higher CO emission rate from the fire box will also mean organics are not being combusted as desired, and organic breakthrough increases as CO increases.

The CO limits are designed to address a pollutant which may increase significantly as an incidental result of compliance with the adopted NO_x limits. Because BIFs and incinerators already have CO limits under regulations designed to ensure destruction efficiency of the wastes combusted, CO limits for these units are not needed in Chapter 117. The commission has exempted BIFs and incinerators from the CO limit of §117.206.

Rhodia stated that the emissions it reported for its BIF unit was based on tons produced and an emission factor as determined by stack testing. Rhodia noted that the proposed emission specification in §117.206(c)(3) is based on the heat input (MMBtu) to the BIF unit and stated that its BIF unit may or may not be classified as a major source, depending on which set of data is used. Rhodia requested clarification of this issue.

The Rhodia BIF was included in the commission's analysis as a unit which would be subject to the NO_x reduction requirement under the ESAD for BIFs. The heat input for this ESAD is intended to include the total heat value of materials fired in the combustion device rather than just supplemental fuel. The emission specifications of §117.206 apply at major sources of NO_x. For HGA, the definition of "major source" includes any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit at least 25 tpy of NO_x. Therefore, NO_x emissions from all stationary sources or groups of sources are included in determining a "major source" classification. The 1997 emissions inventory also listed a fired heater and boiler in the size range to be subject to ESADs at Rhodia's Houston plant.

Solutia stated that it has three BIF units that are used to control VOC emissions from an air oxidation reaction process, but are classified under RCRA as boilers which burn a hazardous waste. Solutia stated that the NO_x emissions from these units result from burning of natural gas and from combustion of organics containing chemically-bound nitrogen. Solutia suggested that a higher emission limit be specified when incineration of chemically-bound nitrogen occurs, or alternatively, that the NO_x limit should exclude NO_x from incineration of nitrogen-bearing compounds.

Today's understanding of NO_x formation includes three different mechanisms for generation of NO_x. Thermal NO_x is formed by the oxidation of atmospheric nitrogen present in the combustion air, prompt NO_x is produced by high speed reactions at the flame front, and fuel NO_x is formed by the oxidation of nitrogen contained in the fuel. Prompt NO_x is more likely to form in a fuel-rich environment because of its dependence on hydrocarbon fragments. This is very different than thermal NO_x, which is highly dependent upon air concentrations.

Chemically bound nitrogen, also called fuel bound nitrogen (FBN), is one of the three common production routes for NO_x emissions. These emissions were presumably reflected in the emission factors that the BIF and incinerator owners provided to the commission in the emission rate survey conducted in the first quarter of 2000. The ESADs were developed from this information and therefore reflect the effects of FBN. NO_x produced by FBN is not any different from NO_x formed by the other formation mechanisms, "thermal" or "prompt" NO_x. Because of this, the presence of FBN does not pose questions of technical feasibility that have not already been considered.

TECHNICAL FEASIBILITY--COKE-FIRED BOILERS

No comments were received on the proposed NO_x emission specification for coke-fired boilers in §117.206(c)(4). This emission specification is adopted without changes.

TECHNICAL FEASIBILITY--WOOD-FIRED BOILERS

Pasadena/Donohue and TPIEC commented on the proposed NO_x emission specification of 0.020 lb/MMBtu for wood-fired boilers in §117.206(c)(5). Pasadena/Donohue stated that one of the wood-fired boilers identified in the rule proposal preamble fires a variety of fuels, including wood, tire-derived fuel (TDF), and wastewater treatment sludge. Pasadena/Donohue stated that nitrogen-containing resins in the wood fuel can be expected to increase NO_x emissions as compared to gas-fired boilers. Pasadena/Donohue stated that SCR has not been demonstrated in wood-fired boilers or in boilers using wood in combination with other fuels, and stated further that while SNCR has been used on base-loaded wood and combination/wood-fired boilers, it has not been demonstrated on such units with changing loads. Pasadena/Donohue stated that an SNCR installation (not identified) on a wood-fired boiler had been unable to consistently meet its target emission limit and had higher than expected ammonia usage and slip. Pasadena/Donohue stated that combustion controls such as FGR and overfire air have not been demonstrated in full-scale combination/wood-fired boilers. Pasadena/Donohue suggested that the proposed NO_x emission specification be changed to 0.30 lb/MMBtu, consistent with the permit limit for one of the wood-fired boilers identified in the rule proposal preamble. TPIEC submitted a September 20, 2000 National Council of the Paper Industry for Air and Stream Improvement, Inc. (NCASI) memo which stated that the requirement to use SCR to achieve a NO_x emission limit of 0.02 lb/MMBtu and over 90% NO_x removal in a wood-fired boiler appears to be based upon the assumption that SCR is applicable to such boilers in a manner similar to utility boilers firing fossil fuels. The NCASI memo stated that use of SCR technology has clearly not been demonstrated for industrial wood, biomass, or combination fuel-fired boilers, and that the issues pertaining to severe energy penalty and space and logistical limitations need to be addressed. The NCASI memo further stated that achieving high levels of NO_x removal using SNCR technologies on wood-fired boilers also has several limitations, including the key one of installing optimally placed injection points for the SNCR chemical in situations of swinging loads and dealing with potentially excessive ammonia slip and plume opacity problems.

The commission agrees that multi-fueled industrial boilers can add some difficulty to the control of NO_x. However, there is enough theoretical and practical experience with SNCR in mixed fuel systems to demonstrate the technical feasibility of SNCR. The science of computer modeling, and the improvement of injection, control, and sensor systems have made this possible. SNCR normally operates with real time control of reagent feed versus load, and follows swings quite closely. Proper use of these inputs also minimizes the formation of ammonia-related problems in the combustion system, cold end, and stack emissions. The commission disagrees with the comments related to the difficulty of installing optimally placed injection points for SNCR, dealing with swinging loads, and the potential for excessive ammonia slip. These features, in fact, are a routine part of commercial SNCR installations. The commission is aware of a mixed fuel industrial boiler (based on wood waste, biomass sludge, etc.) at Bowater Newsprint's pulp and paper mill in Calhoun, Tennessee that is achieving a 62% NO_x reduction with urea-based SNCR. There have been no particular problems with the operation of Bowater's SNCR system since it was installed. There are several other commercial applications of urea-based SNCR on wood/biomass fired systems. SNCR is not adversely affected by inorganics in the exhaust because there is no catalyst to degrade, and the NO_x reductions are favored in the high-temperature zone where SNCR is located. However, SNCR is typically capable of reductions in the 50-60% range, not high enough to achieve the ESAD, although one option would be to install SNCR and use credits, which are available to the owners of the wood-fired boilers, to satisfy the remainder of the reductions.

Although the use of SCR may be technically challenging due to "dirty" exhaust streams, SCR catalyst formulations are adjustable to reduce sensitivities to various catalyst poisons. SCR has been employed in boilers firing high sulfur fuel oil (up to 5.4% sulfur) and on cement kilns in commercial demonstrations in Sweden and Germany. The inorganic compounds and particulate matter present in the exhaust streams of these applications degrade the performance more rapidly than cleaner fuels, thereby shortening the life of the catalysts. Although catalyst replacement cost may be higher relative to a conventional SCR, SCR is still technically feasible. SCR has been operating on a wood-fired boiler at Sauder Woodworking in Ohio since 1994, meeting its NO_x reduction objectives during that time.

In addition to SCR, there are two new oxidation technologies for NO_x reduction which are not yet fully demonstrated. One technology has some demonstration in commercial practice, and the other appears to be moving rapidly to commercial demonstration. One of these, low-temperature oxidation, injects ozone as the oxidant to form N_2O_5, which is then removed in a wet scrubber. Because N_2O_5 is highly soluble in water, this process produced NO_x removal efficiencies in the 99% range (i.e., achieved reductions to two ppm NO_x) when demonstrated commercially on a natural gas-fired boiler in Los Angeles which began operation in October 1996. The other process injects elemental phosphorus as the oxidant to form NO_2, which is also removed in a wet scrubber. The phosphorus based process is anticipated to produce at least 75% reduction in a commercial demonstration on a high sulfur coal-fired utility boiler in Ohio, scheduled for startup in the first half of 2001. The boiler retrofit project is under the financial sponsorship of the owner, a large electric utility.

SCR removal efficiency of 80% would be more representative design goal for dirty fuel streams. The oxidation technologies appears capable of the 90% reductions envisioned by the proposed ESAD. However, developing technologies, like NO_x oxidation, are likely to have more unforeseen practical challenges compared to established technologies and these challenges can compromise performance goals. Because of the concerns raised by the commenters about inorganic materials in the exhaust streams, the commission has modified the ESAD for wood-fired boilers to either an 80% reduction from baseline, or 0.046 lb/MMBtu.

TECHNICAL FEASIBILITY--RICE HULL-FIRED BOILERS

No comments were received on the proposed NO_x emission specification for rice hull-fired boilers in §117.206(c)(6). This emission specification is adopted without changes.

TECHNICAL FEASIBILITY--OIL-FIRED BOILERS

No comments were received on the proposed NO_x emission specification for oil-fired boilers in §117.206(c)(7). This emission specification is adopted without changes.

TECHNICAL FEASIBILITY--IC ENGINES

EMA, ExxonMobil, GPA, Kinder Morgan, Pasadena/Donohue, TCC, Texas Eastern, TGC, and TGP noted that sites with a total of 3,000 hp or more must control all engines to meet a NO_x level of 0.17 g/hp-hr. BCCA, GPA, Kinder Morgan, Texas Eastern, TGC, and TGP questioned why stationary IC engines were singled out as a source category for wholesale replacement. ExxonMobil expressed similar concerns regarding replacement of stationary IC engines with electric drive motors. EMA stated that a stationary gaseous-fueled engine rated at greater than 3,000 hp could meet the proposed limit with advanced SCR, but this control would be costly. GPA, Kinder Morgan, Texas Eastern, TGC, and TGP stated that the emission specifications are unattainable without significant capital expenditure. MECA stated that NSCR can achieve NO_x emission reductions of more than 90% from rich-burn engines or engines operated stoichiometrically at a cost of $10-$15 per brake horsepower (bhp), that

SCR can achieve NO_x emission reductions of more than 90% from lean-burn engines at a cost of \$50-\$125 per bhp, and that lean NO_x catalysts can achieve NO_x emission reductions of more than 80% from lean-burn engines at a cost of \$10-\$20 per bhp. Enron, GPA, Kinder Morgan, Texas Eastern, TGC, and TGP suggested that the emission specifications be set by engine type (i.e., lean-burn or rich-burn), rather than the total horsepower at a site, to account for the more difficult-to-control higher levels of oxygen in the exhaust of a lean-burn engine. TCC, TxOGA, and Union Carbide suggested that the emission specifications be set for individual engines based on engine type or horsepower, rather than the total horsepower at a site. TGP suggested basing the emission specifications on the individual engine emission rate during the baseline periods (1997-1999), horsepower, rather than the total horsepower at a site or even a unit horsepower threshold. TGP also stated that the proposed 3,000 hp cut-off would require that some engines with low historic use and cleaner engines be converted to electric, while smaller base-load engines and older (more polluting) engines located at sites less than 3,000 hp would only have to apply low-NO_x controls but not convert to electric drive. Alternatively, TGP suggested requiring engines that emitted greater than 1.0 tpd in 1997 to be converted to electric (via a 0.17 g/hp-hr limit), with allowances for rich burn engines based on a 95% control from a 1997 baseline rate and allowances for lean-burn engines based on an 88% control from a 1997 baseline rate. For engines that emitted less than 1.0 tpd in 1997, TGP suggested NO_x emission limits of 0.96 g/hp-hr for rich-burn engines and 1.31 g/hp-hr for lean-burn engines, with an exemption for emergency diesel and gas engines. TGP stated that its suggested "tiered control level" would result in a NO_x reduction of 78.02 tpd, as compared to the 78.50 tpd that the commission estimated in the rule proposal preamble. GPA suggested NO_x emission limits of 0.17 g/hp-hr for gas-fired rich-burn engines, and 2.0 to 5.0 g/hp-hr for gas-fired lean-burn engines. TGC suggested NO_x emission limits of 0.17 g/hp-hr for gas-fired rich-burn engines, and 0.50 g/hp-hr for gas-fired lean-burn engines. Texas Eastern suggested NO_x emission limits of 0.17 g/hp-hr for gas-fired rich-burn engines, and 0.51 g/hp-hr for gas-fired lean-burn engines.

The commission re-examined the proposed ESADs for gas-fired stationary IC engines in response to public comment. The basis of the proposed limit for sites with 3,000 hp of gas-fired engines was a strategy of replacement of these engines with electric motors. The proposed ESAD of 0.17 g/hp-hr was developed as an approximate equivalent to the NO_x emissions that would result from EGFs supplying the electricity to operate electric motors at the compressor sites. This emission proposal was not consistent with the other point source emission proposals in the sense that all the others were based on meeting the ESADs through the application of add-on technology. The majority of the engines at sites with 3,000 hp of gas-fired engines are lean-burn engines. It is not technically feasible currently for the large majority of the lean-burn engines to meet a 0.17 g NO_x/hp-hr limit through the application of add-on technology.

In response to the issues raised by the commenters, the commission has adjusted the IC engine ESAD to ensure that the ESADs are technically feasible without wholesale replacement of engines. The adopted ESADs for IC engines are 0.17 g NO_x/hp-hr for gas-fired rich-burn engines, and 0.50 g NO_x/hp-hr for gas-fired lean-burn engines. The adopted ESADs accomplish almost the same level of reduction as the proposed ESADs, while moving the standard to one that is technically feasible based on application of emission controls. The adopted ESADs for IC engines will accomplish all but 1.8 tpd of the 78.5 tpd of NO_x reductions estimated in the rule proposal preamble.

These changes have the potential to reduce required capital expenditures significantly on a number of the engines. Approximately 50 of the lean-burn engines operate below 5.0 g NO_x/hp-hr, and these engines can be retrofitted with flue gas cleanup controls to meet the adopted ESAD of 0.50 g/hp-hr instead of being forced to convert to electric motors or obtain allowances. In the cost note of the proposal preamble, the commission estimated the cost of electrification at approximately \$800 per hp, including cost of electric transmission lines. The preamble used the equation (\$310,000 plus (\$72.7 times hp)) to estimate SCR capital cost. Applying this equation to 42 of the engines with reported emissions below 5.0 g NO_x/hp-hr yields an average cost of \$462/hp. However, for engines with higher emission baselines, the capital costs of electrification and Tier III controls are similar, so the adopted ESADs are still expected to result in the replacement of IC engines with electric drive motors, as in fact has already occurred at some sites due to such factors as the cost savings associated with increased automation and reduced labor costs for engine maintenance. Many of the gas-fired engines are more than 40 years old and replacing them will also offer the opportunity to make other upgrades at the plants, such as in metering and control. The conversion of gas-fired engines to electric motors will remove the highest stationary source NO_x emitters from the airshed. However, with the adopted ESADs and the compliance flexibility offered by the cap and trade compliance program, a variety of strategies are expected to be used to reduce emissions. Many of the IC engines are transportable and some of the lean-burn engines could be swapped for rich-burn engines controlled with NSCR. Conversion to electric motors may be favored at sites with access to existing power lines of the appropriate size. The EPA's NO_x SIP call rules applicable in 22 eastern states of the United States include requirements for IC engines, which is currently stimulating development of new NO_x control technologies which may have applicability to the lean-burn gas engines in HGA.

BCCA stated that it reviewed worldwide retrofit experience for IC engines, and that it found no equipment designed for and meeting the proposed emission standards. BCCA asserted that the commission failed to take this worldwide lack of experience into account when setting the proposed emission limits.

The commission disagrees that there is no equipment designed for and meeting the adopted emission specifications. The adopted rich-burn engine ESAD of 0.17 g/hp-hr is achieved with NSCR technology. The EPA recently sponsored an update of the 1993 ACT for IC engines. This document, *Stationary Reciprocating IC Engines, Updated Information on NO_x Emissions and Control Techniques, Revised Final Report*, September 1, 2000, provides a review of NSCR performance testing in several California air quality districts. Test data from Santa Barbara County included 78 engines equipped with NSCR, representing 17 models in size from 48 hp to 747 hp. In 163 tests of these engines, the mean emission rate was 0.17 g/hp-hr. The adopted ESAD for lean-burn IC engines is similar to the current VCAPCD rule, which is approximately equal to 0.62 g NO_x/hp-hr. Under the previous version of the VCAPCD rule, which required only an 80% reduction, several IC engine tests indicated lower levels than 0.5 g/hp-hr using SCR.

Pasadena/Donohue stated that it should be clarified that only gas-fired engines count toward the 3,000 hp cutoff.

The proposed and adopted ESADs are intended to apply only to gas-fired engines. In order to clarify this intent, the term "gas-fired" has been inserted in the IC engine ESADs of §117.206(c)(9). As discussed earlier in this preamble, the adopted ESADs are based on categorization as rich-burn or lean-burn rather than total site hp.

BCCA asserted that the preamble does not provide sufficient information to adequately analyze alternative approaches and stated that it was impossible to discern the relative number of rich-burn versus lean-burn affected engines or the average horsepower of either class, or the relative contribution of either class to the total tpd reduction.

BCCA member company ExxonMobil and several other companies requested and received from commission staff during the public comment period the emission inventory information used to develop the proposed IC engine ESADs. In their comments on the proposed rules, several of these companies included an analysis of the emission reductions that could be achieved by various suggested regulatory alternatives, including ones based on rich-burn or lean-burn characteristics.

Regarding reliability, Kinder Morgan, TGC, and TGP stated that they, like other interstate natural gas transmission companies, operate under a certificate issued by the Federal Energy Regulatory Commission (FERC), and that this certificate requires them to make available the necessary horsepower developed by the engines to compress and deliver natural gas to its customers throughout the country. GPA, TGC, and TGP stated that HGA forms a "hub" through which several interstate natural gas pipeline companies carry natural gas from the Gulf of Mexico to various parts of the country and stated that a compressor station that operates solely under electric power may not be able to transport natural gas to its customers in other parts of the country during periods of power failure or "brownouts." As examples of reliability concerns, GPA and TGP cited the acute power shortage during summer 2000 in Southern California and in past years in the northeast. TGP suggested that the rule allow at least 50% of natural gas compressors at a compressor station to remain gas-fired to ensure reliable transportation of natural gas during peak demand on the power grid.

Reliable transport of natural gas is important and the shift to electric motors in the transmission industry needs to be accompanied with contingency planning to ensure that power failures or brownouts do not seriously disrupt the ability to move gas. The cap and trade program makes it feasible to retain any number of existing gas-fired engines as standby units, operating only under emergency or maintenance conditions, with electric motors moving gas under all non-emergency conditions. Because electric motors generate no NO_x emissions, they would generate emission credits to cover NO_x emissions resulting from emergency or test operation of gas-fired engines. An additional compliance option made feasible by the adopted ESADs for gas-fired IC engines would be to forego electric motors and comply by adding NO_x control technology to the existing gas-fired engines.

BCCA and Kinder Morgan commented on the ability of lean-burn gas-fired engines to meet a NO_x level of 0.50 g/hp-hr. BCCA and Kinder Morgan asserted that SCR retrofits have been tried on a small number of engines in gas compression service in California with negative results and that in all cases the operators who installed retrofit SCR abandoned its use, preferring instead to either accept a loss of capacity or find another way to achieve emission reductions. BCCA stated that EPA's ACT document, *Alternative Control Techniques Document--NO_x Emissions from Stationary Reciprocating Internal Combustion Engines*, Table 2.5, indicates that SCR can achieve 90% reduction on lean-burn engines. BCCA stated that only three of the six engines tested achieved 90% reduction on any test; only one engine (a small (291 hp), non-typical gas engine) reported greater than 90% reductions for all tests conducted; two other engines achieved 90% reduction on at least one test, but did not achieve that level on other tests; and two engines had at least one test that reported zero NO_x reduction. BCCA stated that test data with such variation over such a small sample is inadequate to support a decision to impose wide-scale retrofit of SCR technology on lean-burn engines. Kinder Morgan suggested that the commission reconsider the emissions specifications for lean-burn IC engines and establish emission limits based on existing, proven LEC technology.

Much of the SCR operating data in the 1993 ACT for gas compressor engines comes from a data base of test results for engines in Ventura County, California. This data was revisited in the September 1, 2000 EPA document, *Stationary Reciprocating IC Engines, Updated Information on NO_x Emissions and Control Techniques, Revised Final Report*. The Ventura County data base includes 49 tests on seven engines with SCR, tested between 1986-1993. The engines were subject to the rule limits at the time, either a limit of 125 ppmv (approximately 1.7 g/hp-hr), or an 80% reduction. Rule compliance was indicated in all but two tests of one engine, an engine then taken out of service. Upstream concentration data, available on 42 of the compliance tests, shows an 84% average reduction. This data is clearly supportive of the ability of the technology to make the reductions necessary for compliance with the VCAPCD rule in effect. The fact that 90% reduction was only achieved on some of the tests is a function of the regulatory standards in place, rather than technical feasibility. SCR is a versatile technology and is capable of achieving reductions above 90%. In addition, as discussed in the response to the following comment, the Ventura County data from 1986-1993 represents the performance of first generation SCR on lean-burn IC engines, not current SCR capabilities. In 1993, Ventura County further tightened the NO_x emission limits to 45 ppm (approximately 0.62 g/hp-hr) or a 94% reduction, intentionally causing a shift from SCR-controlled engines to electric motors.

BCCA, Goodyear, GPA, Kinder Morgan, Texas Eastern, TGC, and TGP stated that most engines in this class are used in either gas compression service or electrical power generation, both of which require that the engine follow swings in load, and that SCR is not very responsive to changing loads due to its inability to rapidly achieve a balance between inlet concentrations of NO_x and the ammonia injection. BCCA, Goodyear, and GPA stated that there have been no successful application of post-combustion control technology on load-following, lean-burn IC engines for a number of technical reasons, including difficulty in achieving and maintaining the required temperature window and residence time for the NO_x reduction reactions to be effective. BCCA and GPA stated that some SCR vendors contend that the feedback problem has been solved by the application of modern PEMS which can react more rapidly than instruments, but that application of PEMS to date has been very limited and has been generally limited to new, well-instrumented, smaller, medium- to high-speed engines. BCCA stated that there is little evidence that it would be possible to retrofit adequate PEMS systems on the older, large bore, low speed engines in current use in HGA.

The first generation of SCR applied to engines did not address load following operation very well and as a result, SCR performance was not always acceptable. The new generation of SCR technology has demonstrated the ability to perform under engine load swings. In one example of SCR with feedforward controls on three 3,130 hp lean-burn engines operated in pipeline service at variable speed and load, during 20 individual test runs, the engines were found to be operating at between 0.11 g NO_x/hp-hr and 0.21 g NO_x/hp-hr. These emissions are well below the adopted 0.50 g NO_x/hp-hr ESAD for lean-burn gas engines. The nature of technological advance is that once a problem is solved, it no longer exists as a problem of whether it can be done, but as matter of application. The application of feedforward controls will be simpler on the better-instrumented engines, but the upgrade of lean-burn engines currently with older operating controls is technically feasible and could be performed in conjunction with Tier I low emission combustion modifications. Tier I retrofits will be needed for most of the older engines to bring emissions down to the range of 5.0 g NO_x/hp-hr, in order for SCR or other flue gas cleanup controls to further reduce emissions by 90% to 0.5 g NO_x/hp-hr. LEC retrofits are capable of achieving NO_x levels of two to three g/hp-hr on most engine models, adding flexibility to the combination of Tier I and Tier II controls necessary to achieve the lean-burn engine ESAD.

As an alternative to SCR, NO_x adsorber catalyst technology is not as sensitive as SCR to variations in inlet NO_x concentration and appears to be promising in load-following gas-fired IC engine applications. The first commercial application of this technology to three 2,000 hp gas-fired lean-burn engines is underway at a semiconductor manufacturing facility in Dallas. The permit limit for these engines is 0.070 g/hp-hr, significantly lower than the adopted ESAD for lean-burn gas engines.

Goodyear stated that for gas-fired lean-burn engines rated at 700 hp or less, the proposed emission specification should be revised to limit NO_x emissions to no less than 4.0 g/hp-hr. Alternatively, Goodyear suggested that these engines be exempted. TGP suggested that the emission specifications be based upon NSR permitting BACT levels.

The commission disagrees with Goodyear's suggestions because if implemented they would result in minimal reductions from many stationary IC engines to which technically feasible controls can be applied to accomplish the necessary emission reductions. TGP's suggestion to base the emission specifications on NSR permitting is not a clear cut suggestion. Written guidance for IC engine BACT hasn't been updated in some time and does not reflect the capabilities of today's technology. For example, as discussed in the preceding response, the commission recently issued a construction permit for three 2,000 hp gas-fired engines with a NO_x emission limit of 0.070 g/hp-hr, using Tier III control technology. The new engines' combustion design is guaranteed to achieve an emission rate of 0.7 g/hp-hr, which currently would not be a technically feasible Tier I level for low emission combustion retrofits.

TECHNICAL FEASIBILITY--PULPING LIQUOR RECOVERY FURNACES

BCCA, Sierra-Houston, Pasadena/Donohue, and TPIEC commented on the proposed NO_x emission specification of 0.050 lb/MMBtu for pulping liquor recovery furnaces in §117.206(c)(12). BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for pulping recovery furnaces. Sierra-Houston stated that the NO_x emission specification should be more stringent, while Pasadena/Donohue stated that §117.206(c)(12) should be deleted and §117.203 revised to specifically exempt pulping liquor recovery furnaces. TPIEC submitted a September 20, 2000 NCASI memo which stated that the requirement to use SNCR to achieve 64% NO_x reduction in a kraft recovery furnace is apparently based upon results from test runs conducted on the Swedish furnace in the early 1990s. The NCASI memo stated that the furnace on which the tests were conducted has since been decommissioned and a new furnace built at the same mill does not incorporate SNCR technology, and asserted that there is no published information on the use of SNCR on an existing and operating furnace anywhere in the world. Pasadena/Donohue similarly asserted that there has been no continuous demonstration of SNCR on a pulping recovery furnace and that a trial was conducted but the results were not conclusive, the trial furnace was shut down after the trial, and its replacement furnace was not equipped with SNCR. The NCASI memo stated that there are a number of unresolved critical issues surrounding the use of urea or ammonia injection in a recovery furnace for NO_x control, and that the design and function of a recovery furnace is first and foremost to operate as a chemical reactor to recover expensive cooking chemicals, with its role as a steam-producing device secondary to this primary function. The NCASI memo stated that long-term tests need to be conducted on a furnace to ensure the injection of NO_x-reducing chemicals would not have any deleterious consequences on the kraft liquor chemical cycle. The NCASI memo also expressed concern about other unknown factors such as significant ammonia slip and corresponding impact on tube corrosion and fouling, potential for plume opacity problems due to ammonium chloride emissions, etc. NCASI stated that optimization of the staged combustion principle within an existing furnace to possibly obtain up to 30% reduction in prevailing NO_x emissions is perhaps the only technologically feasible alternative at the present time. Pasadena/Donohue stated that combustion controls which reduce combustion temperature could result in increased total reduced sulfur (TRS) and CO emissions, since increased temperature is used to control sulfur dioxide (SO_2) and TRS. Pasadena/Donohue stated that reduced furnace temperature could risk terminating the oxidation of the black liquor solids, resulting in "a significant explosion threat to the mill." Pasadena/Donohue stated that use of ammonia associated with SNCR in a sulfur-rich environment will result in the formation of ammonium sulfates and cause particulate and opacity problems. Pasadena/Donohue also stated that introduction of nitrogen (in the form of urea or ammonia) into the furnace will increase the concentration of nitrogen in the chemical recovery cycle (i.e., the black liquor, smelt, lime mud, and white liquor) since it is a closed system, such that any nitrogen captured in the electrostatic precipitator (ESP) or with the smelt will be released in the smelt tank, the lime kiln, or the recovery boiler, thereby possibly increasing NO_x emissions.

The commission disagrees with the commenters. There appears to be a basic misunderstanding of the chemistry of SNCR that is put forward as the primary theoretical roadblock to its use in pulping liquor recovery furnaces. The issue of ammonia being somehow trapped in the "closed cycle" of the process, and concentrated to an undesirable level, coupled with high level of sulfur compounds, is not relevant in a mill using alkaline (black liquor) pulping. With large amounts of alkaline sodium and sodium oxide present, ammonia will not form ammonium sulfate salts. Instead, the sodium, being a much stronger reactant, will form sodium sulfate salts, causing the ammonia to remain in the gas phase and leave the system, rather than deposit in the ESP as the commenter asserted. Also, the commenters lack understanding of the complexity of the urea, ammonia, and NO_x reactions, as well as the amount of ammonia produced for every pound of urea fed. There are many other reaction paths that occur, including the conversion of urea to diatomic nitrogen and water, with a relatively small percentage leaving as ammonia slip. Urea reagent use actually tends to simplify the control of excess ammonia produced. Control of the excess ammonia generation is a part of the art and the science, as well as the economics, of the SNCR process, and a competently designed and operated system will minimize it. Indeed, an SNCR vendor typically guarantee five to ten ppm ammonia slip. The commission believes that issues related to ammonia release or concentration have been overcome through commercial development and experience in the last ten years.

As noted in the rule proposal preamble, the emission specification was based on the application of SNCR, which has previously been demonstrated to be technically feasible on a pulping liquor recovery furnace in 1991. That a subsequent replacement furnace was not equipped with SNCR may merely reflect the company's business decision not to spend the money to equip the new furnace with SNCR in the absence of regulations or BACT permitting requirements mandating NO_x reductions that would motivate the company to install NO_x post-combustion control technologies. The commission has retained the ESAD for pulping liquor recovery furnaces as proposed, but has added an alternative ESAD of 1.08 lb NO_x per ADTP. Both pulping liquor recovery furnace ESADs provide for a NO_x reduction of 64%.

Pasadena/Donohue expressed compliance demonstration concerns, stating that measuring the furnace activity level is not easy and that there is no fuel source to meter since the furnace is normally heated via combustion of the organic matter in the black liquor solids. Pasadena/Donohue also stated that the organic content (and therefore the heating value) of the black liquor solids is highly variable, thus disallowing use of feed rate monitoring.

The commission agrees that pulping liquor recovery furnaces should be excluded from the fuel flow meter requirements for the reasons cited by the commenter. The commission has revised §117.213(a)(1)(B) accordingly. The commission has also revised §117.213(a)(1)(B) to exclude wood-fired boilers from the fuel flow meter requirements since it is impractical to install a monitor for fuel flow of a solid fuel.

TECHNICAL FEASIBILITY--LIME KILNS

BCCA, Sierra-Houston, Pasadena/Donohue, and TPIEC commented on the proposed emission specification for lime kilns in §117.206(c)(13)(A). BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for lime kilns, while Sierra-Houston stated that the proposed emission specification for lime kilns should be more stringent. Pasadena/Donohue stated that §117.206(c)(13)(A) should be deleted and §117.203 revised to specifically exempt lime kilns. Pasadena/Donohue stated that staged combustion and mid-kiln firing have not been demonstrated on lime kilns and therefore are not technically feasible. Pasadena/Donohue stated that low-NO_x burners are not technically feasible on lime kilns due to "complexities resulting in poor efficiency, increased energy use, and decreased calcining. In addition, there is limited ability to reduce temperature in the kiln and stay within regulated limits for TRS emissions and maintain calcining capacity." TPIEC submitted a September 20, 2000 NCASI memo which stated that the requirement to use combustion controls such as low-NO_x burners, mid-kiln firing, and staged combustion to effect a NO_x removal capacity of about 39% is perhaps based upon their application to cement kilns rather than kraft pulp mill lime kilns. The NCASI memo stated that based upon an average lime kiln NO_x emission factor of 2.19 lb/ton CaO, a 70% reduction would be needed to get to an emission of 0.66 lb/ton CaO (and not 39%). The NCASI memo further stated that kraft lime kilns generally have limited operating flexibility relative to combustion NO_x controls in order to achieve the primary goal of kiln operation: a desired reburned lime purity and production rate. The NCASI memo stated that in order to keep the TRS emissions below what is typically an extremely tight limit (e.g., ten ppm TRS at 10% O_2), efforts to ensure TRS control take precedence over all other emission control strategies, and that low-NO_x burners on lime kilns are undesirable for these reasons. The NCASI memo further stated that mid-kiln firing is believed infeasible in the case of kraft lime kilns, although it may be a technology that is applicable to cement kilns. The NCASI memo stated that staged combustion may have only limited applicability due to the potentially undesirable impact on calcining capacity and kiln energy efficiency, as well as other potentially undesirable impacts on emissions of TRS and hazardous air pollutant (HAP) compounds.

The commission disagrees with Pasadena/Donohue's assertion that staged combustion and mid-kiln firing have not been demonstrated on lime kilns and therefore are not technically feasible. As noted earlier in this preamble, the installation of a control technology at a single source can sufficiently demonstrate its technical feasibility, and installation of a control technology at a source in one source category often can be "transferred" to other source categories. Also, the NCASI memo did not explain the basis for its assertion that "mid-kiln firing is believed infeasible in the case of kraft lime kilns." Nevertheless, in the case of lime kilns, at least two technologies can be transferred from the cement industry. One is reburn technology, in which reburn air is injected mid-kiln for rapid and complete cross-sectional mixing of the injected air with the gases in the kiln. The air is injected downstream of a substoichiometric zone in a gas temperature range sufficient to complete the combustion of residual CO and hydrocarbons. NO_x reduction is achieved by completely depleting the oxygen in the primary combustion zone, and providing the finishing oxygen in the proper temperature zone to complete combustion and minimize further NO_x formation.

In addition, low-NO_x natural gas burners are available that incorporate controlled flame turbulence, delayed fuel air mixing, establish a fuel rich zone, and achieve rapid ignition. Most gas burners incorporate the first three principles; however, because they use no primary air, ignition is delayed. Consequently, they do not take advantage of combustion in fuel rich zones, and the flames only burn on the surface where air has been able to mix. Low-NO_x gas burners use some primary air or a means of getting enough oxygen to the core of the flame to establish ignition. Low-NO_x burners have been installed in European lime kilns.

The NCASI memo recognized that NO_x emissions are a function of hot end temperature for gas-fired kilns. Since there is an incentive to operate at the lowest temperature that product can be made in order to minimize fuel costs, knowing the instantaneous NO_x level through the use of a NO_x monitor could be used in process control such that corrective action is taken to adjust the process when the NO_x level indicates a more-than-adequate temperature in the kiln. Reductions in the NO_x mass emission rate would come about through reduced fuel use and the associated reduced NO_x concentration. Tight process control using CO and O_2 monitoring in addition to NO_x should result in reduced NO_x emissions. Use of a NO_x monitor will also enable accurate characterization of NO_x behavior leading to additional NO_x reduction strategies.

As noted earlier, low-NO_x burners have been installed in European lime kilns. The commission acknowledges that it is not aware of specific situations in which combustion controls were used on lime kilns in the United States. However, it is also true that there have been no lime kiln regulations requiring NO_x reductions that would motivate potential users to install NO_x combustion control technologies. As NESCAUM (www.nescaum.org) noted in *Environmental Regulation and Technology Innovation: Controlling Mercury Emissions from Coal-Fired Boilers* (Publication SS-25, September 2000), implementation of technology historically follows regulation, and not the reverse. Once clear, enforceable standards are set, the regulated community and technology vendors have proven adept at finding cost-effective solutions and then implementing them.

TECHNICAL FEASIBILITY--LIGHTWEIGHT AGGREGATE KILNS

BCCA, Sierra-Houston, and TXI commented on the proposed emission specification of 0.76 lb NO_x per ton of product for lightweight aggregate kilns in §117.206(c)(13)(B). BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for lightweight aggregate kilns, while Sierra-Houston stated that the proposed emission specification should be more stringent. TXI stated that its lightweight aggregate kilns are fired on coal and natural gas, and must utilize approximately 100% excess air to properly operate and produce the desired product. TXI stated that it did not believe that the commission adequately investigated the technical feasibility of installing combustion controls on lightweight aggregate kilns. TXI stated that it is not aware of any technical information which indicates that SCR or SNCR has even been considered for use on lightweight aggregate kilns. TXI stated that other NO_x reduction techniques provide other difficulties in their application to lightweight aggregate kilns.

The commission agrees that high excess air is necessary in lightweight aggregate kilns to obtain the necessary thermal profile to expand the shale. The commission has investigated the technical feasibility of installing combustion controls on lightweight aggregate kilns. Specifically, FGR, reburn technology, and steam or water injection are available combustion controls technologies which will reduce NO_x emissions on lightweight aggregate kilns while maintaining the temperature profile necessary for producing the desired product. In FGR, low oxygen flue gas is substituted for the excess air. This flue gas replaces the thermal mass of excess air in the main flame, thereby maintaining the required thermal profile. At the same time, the flame burns in a reduced oxygen atmosphere initially and burns out at near stoichiometric conditions. The reduced availability of oxygen throughout the entire combustion process results in reduced NO_x formation.

Further NO_x reductions can be achieved by combining FGR with reburn technology, in which reburn air is injected mid-kiln for rapid and complete cross-sectional mixing of the injected air with the gases in the kiln. The air is injected downstream of a substoichiometric zone in a gas temperature range sufficient to complete the combustion of residual CO and hydrocarbons. NO_x reduction is achieved by completely depleting the oxygen in the primary combustion zone, and providing the finishing oxygen in the proper temperature zone to complete combustion and minimize further NO_x formation.

A second method of adding thermal ballast to the flame of a lightweight aggregate kiln is by substituting steam or water for excess air. By adding water vapor to the combustion air, the thermal properties of high excess air can be achieved and the oxygen input can be kept near stoichiometric. Using water instead of air also enables the application of the previously described reburn technology where the main flame is operated slightly substoichiometric, and the overhead air is added downstream. Other available combustion controls are low-NO_x burner retrofits, and midkiln firing of coal or dewired tire chips. Both low-NO_x burners and midkiln firing are documented as successfully reducing NO_x emissions on cement kilns by over 30%, and it is reasonable to expect that similar emission reductions could be achieved on lightweight aggregate kilns. The adopted ESAD of 0.76 lb NO_x per ton of aggregate produced was calculated as a 30% reduction from the baseline emissions for these kilns, so the adopted ESAD is technically feasible.

In addition, since there is an incentive to operate at the lowest temperature that product can be made in order to minimize fuel costs, knowing the instantaneous NO_x level through the use of a NO_x monitor could be used in process control such that corrective action is taken to adjust the process when the NO_x level indicates a more-than-adequate temperature in the kiln. Reductions in the NO_x mass emission rate would come about through reduced fuel use and the associated reduced NO_x concentration. Tight process control using CO and O_2 monitoring in addition to NO_x should result in reduced NO_x emissions. Use of a NO_x monitor will also enable accurate characterization of NO_x behavior leading to additional NO_x reduction strategies.

Regarding post-combustion controls, the commission acknowledges that it is not aware of specific situations in which SCR or SNCR were considered for use on lightweight aggregate kilns. However, it is also true that there have been no lightweight aggregate kiln regulations requiring NO_x reductions that would motivate potential users to install these technologies. As noted earlier in this preamble, implementation of technology historically follows regulation, and not the reverse. Once clear, enforceable standards are set, the regulated community and technology vendors have proven adept at finding cost-effective solutions and then implementing them.

TXI suggested that NO_x emissions from lightweight aggregate kilns be addressed through the NSR permitting process, and noted that its kilns were already operating under NSR permits.

The commission disagrees with the commenter's suggestion because if implemented, the result would be no emission reductions from lightweight aggregate kilns to which technically feasible controls can be applied to accomplish the necessary emission reductions, and would increase the NO_x cap established under the mass emissions cap and trade program.

TXI stated that the wording of the rule proposal preamble suggests that the only basis for the proposed emission specification is a 30% reduction from a 1997 baseline of 1.088 lb NO_x per ton of product. TXI stated that its emission rate has ranged from

1.088 lb NO_x per ton of product to 1.39 lb NO_x per ton of product, and that the proposed emission specification utilized the low end of this range by using 1997 as the baseline year. TXI commented that a reduction of 55% would be needed for continuous compliance.

The commission disagrees with the commenter. As noted earlier in this preamble, the commission staff used the 1997 emissions inventory as the basis for considering various combinations of ESADs for various categories of equipment to achieve a 90% reduction in point source NO_x emissions. Use of the 1997 emissions inventory is consistent with the method of analysis for all other equipment categories. In addition, use of the 1997 emissions inventory is consistent with the photochemical modeling analyses of NO_x point source emissions in support of the HGA ozone attainment demonstration, which are based on 1997 emissions. Therefore, use of the 1997 baseline was not arbitrary, as the commenter has implied, but in fact a necessary and consistent component of an approvable SIP revision. The commission also notes that the ESADs are used to establish allocations (NO_x emissions in tons) for the mass emissions cap and trade program. The commenter's concern that a greater reduction than actually represented by the lightweight aggregate kiln ESAD is needed for "continuous compliance" is unwarranted since the allowances are allocated on a calendar year basis.

SCR removal efficiency of 80% would be a more representative design goal for dirty exhaust streams. The oxidation technologies appears capable of a 90% NO_x reduction. However, developing technologies, like NO_x oxidation, are likely to have more unforeseen practical challenges compared to established technologies that can compromise performance goals. Therefore, the commission has adopted the ESAD for lightweight aggregate kilns as proposed.

TECHNICAL FEASIBILITY--HEAT TREAT AND REHEAT FURNACES

BCCA, Sierra-Houston, and Wyman-Gordon commented on the proposed emission specifications for heat treat furnaces and reheat furnaces in §117.206(c)(14). Wyman-Gordon stated that the rule proposal preamble incorrectly identified its steel processing plant as having seven reheat furnaces and two heat treating furnaces subject to the proposed rule, noting that these furnaces are actually five reheat furnaces and four heat treating furnaces. Wyman-Gordon stated that correct classification is important because the emission specifications and costs are different for the two types of furnaces.

The commission agrees that correct classification of the furnaces is important, and notes that the commission's classification of the commenter's furnaces in the rule proposal preamble was based on information that the company submitted in its 1997 emissions inventory. The commission has corrected the classification of Wyman-Gordon's reheat furnaces and heat treating furnaces in the table in the Tables and Graphics section of this issue of the *Texas Register*, titled "Subcategories--Point Source Potential NO_x Emission Reductions for Houston/Galveston Nonattainment Area Counties."

BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for heat treat and reheat furnaces. Wyman-Gordon commented that the EPA's *Alternative Control Techniques Document--NO_x Emissions From Iron and Steel Mills* states on page 5-8 that heat treat furnaces "operate at a very specific flame point and furnace geometries to achieve a specific 'set point' past which steel processing is most efficient; major problems may occur for a specific furnace without a large amount of equipment reconstruction." Wyman-Gordon stated that its furnaces have custom designed and built proprietary burners which already have very low NO_x emission rates as compared to standard burners commonly used in reheat and heat treat furnaces. Wyman-Gordon stated that because the burners are custom built, it is not possible to retrofit the burners with an "off the shelf" low-NO_x package and that instead, each burner would need to be completely rebuilt or replaced to achieve the proposed emission rates. Wyman-Gordon also stated that the new burners would have different flame characteristics than the existing burners, requiring modeling and an engineering study to determine the correct placement to achieve uniform heating in the furnaces. Wyman-Gordon stated that the commission assumed an unreasonably low NO_x emission rate from uncontrolled furnaces, and that the EPA and State and Territorial Air Pollution Program Administrators (STAPPA)/Association of Local Air Pollution Control Officials (ALAPCO) developed higher emission rates for controlled and uncontrolled heat treat and reheat furnaces. Wyman-Gordon stated that the proposal should be revised to reflect more realistic uncontrolled emission rates and to reflect the fact that most furnaces use pre-heated air, and that otherwise it would have to reduce its preheated air reheat furnace emissions by 70% and its heat treat furnace emissions by 93%. Wyman-Gordon stated that these reductions are greater than those specified in the proposal and may not be achievable, or may require installation of both low-NO_x burners and SCR at a "dramatically" increased cost of control.

The commission agrees that accurate information is important and notes that the emission rates for the commenter's furnaces were supplied by the commenter as part of the commission's rate data survey of the 1997 emissions inventory. The commission also notes that Tier I control options other than low-NO_x burners are available to reduce emissions from heat treat furnaces and reheat furnaces. For example, an external gas conditioning system can be added which introduces inert gas using existing fuel pressure (i.e., without moving parts) into an eductor where it dilutes the fuel to produce a low-NO_x fuel. The inert gas reduces peak flame temperatures, lowers available O_2 concentration, and minimizes reaction times, thereby reducing both prompt NO_x and thermal NO_x formation. Under demonstration on a utility boiler in Texas, this is currently achieving 0.04 lb/MMBtu, with expectations of even better performance. Other control options are also available. The owner or operator of each affected source is free to choose the control technology which best addresses the circumstances of the affected sources, obtain additional allowances from another facility's surplus allowances, or a combination of the two approaches.

Sierra-Houston stated that the emission specification for heat treat furnaces and reheat furnaces in §117.206(c)(14) should be more stringent. Wyman-Gordon stated that its 1997 emissions inventory reflects calculation of potential emissions rather than actual emissions, thus overestimating natural gas usage and, in turn, daily and annual emission rates. Wyman-Gordon suggested that the uncontrolled emission rate for its heat treat furnaces and reheat furnaces be set at 0.20 lb/MMBtu, and the emission specification for heat treat furnaces and reheat furnaces set at 0.13 and 0.10 lb/MMBtu, respectively.

The commission disagrees with Wyman-Gordon's suggested ESADs because they would result in no emission reductions from heat treat furnaces and reheat furnaces to which technically feasible controls can be applied to accomplish the necessary emission reductions. In addition, the suggested ESADs would increase the NO_x cap established under the mass emissions cap and trade program. The commission evaluated a variety of possible ESADs and has adopted the ESADs for heat treat furnaces and reheat furnaces as proposed.

TECHNICAL FEASIBILITY--DRYERS

BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for dryers.

As the commission stated in the rule proposal preamble, "(t)he proposed emission limit for magnesium chloride fluidized bed dryers is a 90% reduction from 1997 ozone season daily NO_x emissions. The proposed 41% NO_x emission reduction from the dryer category would be expected to necessitate SCR on the one affected dryer; however, this dryer is currently shut down. According to the company, there are no plans to reactivate this dryer. Consequently, the total annual fiscal impact for dryers in HGA is assumed to be zero." (See the August 25, 2000 issue of the *Texas Register* (25 TexReg 8290).) Because the one affected dryer has been permanently shut down, there is no need for a detailed technical discussion of the technical feasibility of the ESAD for dryers. However, SCR is a well-established Tier II flue gas NO_x control technology. The technical issues of SCR on dryers are expected to be similar to those for other NO_x source categories.

Sierra-Houston stated that the emission specification for dryers in §117.206(c)(15) should be more stringent.

The commission disagrees with the commenter. The emission specification will require a 90% reduction from the emission factor used to calculate the 1997 ozone season daily NO_x emissions, and will affect a single dryer which had reported NO_x emissions of 1.05 tpd (383.87 tpy) in 1997. No other dryer in HGA had NO_x emissions greater than 0.07 tpd. The commission believes that the emission specification is appropriate, but has replaced the phrase "1997 ozone season" with "June-August 1997" since ozone season is not defined. It should be noted that the commission identified approximately 45 dryers with 1997 emissions of 0.01 to 0.07 tpd. In the future, the commission may pursue emission reductions from these currently-exempt dryers in HGA if additional reductions are determined to be necessary to reach attainment with the ozone NAAQS.

TECHNICAL FEASIBILITY--INCINERATORS

BASF, Sierra-Houston, Pasadena/Donohue, Safety-Kleen, and TPIEC commented on the proposed NO_x emission specification for incinerators in §117.206(c)(16), 10% of the 1997 rates (i.e., a 90% reduction from the 1997 rates). BCCA stated that there is no analysis in the rule proposal preamble to describe the technical feasibility of the proposed retrofit limits for incinerators. Sierra-Houston stated that the emission specification for incinerators should be more stringent. Safety-Kleen stated that incinerators are designed to destroy organic contaminants in waste streams that cannot be disposed by other methodologies. Safety-Kleen stated that many of those streams contain irreducible levels of compounds that contribute to the generation of NO_x when the waste is incinerated. Safety-Kleen stated that waste streams are typically the by-products of production processes, and therefore, control on the quality of waste streams rests entirely in the hands of the generators. Safety-Kleen stated that many waste streams contain chemical-bound nitrogen and that the market for these wastes is growing. Safety-Kleen stated that it has systems in place to predict Btu-loading, ash-loading, metals emission, and the formation of by-products which could damage the refractory lining of the units, but that due to the waste's variability and the uncertainty of the possible mechanisms for NO_x formation during the simultaneous incineration of multiple waste streams, it is extremely difficult to predict NO_x formation. Safety-Kleen stated that SNCR is "the most stringent NO_x-reduction technology available" and has been shown to reduce NO_x emissions by up to 80-90%, but that SNCR will, by itself, be inadequate to control meet the proposed emission specifications. Safety-Kleen also stated that SNCR designs are predicated on singular waste streams with no variability, and that a 90% reduction in NO_x emissions has never been demonstrated in the hazardous waste industry.

The commission considered the waste streams in the HGA incinerators in response to these comments and agrees with the commenters that certain of the units have "dirty" exhaust streams, primarily with sulfur and chlorides, and a few with some metals and other inorganics. The units with "dirty" exhaust streams use wet scrubbers to remove acid gases and some of the other inorganics. Considering the "dirty" streams, SCR has been employed in a few high sulfur fuel oil applications, but the inorganic compounds present in the exhaust degrade the performance more rapidly than cleaner fuels. SNCR will not be adversely affected by these inorganics, because there is no catalyst to degrade and the NO_x reductions are favored in the high-temperature zone where SNCR is located. However, SNCR is typically capable of reductions in the 50-60% range, not high enough to achieve the ESAD.

In addition to SCR, there are two new oxidation technologies for NO_x reduction which are not yet fully demonstrated. One technology has some demonstration in commercial practice, and the other appears to be moving rapidly to commercial demonstration. One of these, low-temperature oxidation, injects ozone as the oxidant to form N_2O_5, which is then removed in a wet scrubber. Because N_2O_5 is highly soluble in water, this process produced NO_x removal efficiencies in the 99% range (i.e., achieved reductions to two ppm NO_x) when demonstrated commercially on a natural gas-fired boiler in Los Angeles which began operation in October 1996. The other process injects elemental phosphorus as the oxidant to form NO_2, which is also removed in a wet scrubber. The phosphorus based process is anticipated to produce at least 75% reduction in a commercial demonstration on a high sulfur coal-fired utility boiler in Ohio, scheduled for startup in the first half of 2001. The boiler retrofit project is under the financial sponsorship of the owner, a large electric utility.

The commission believes that the exhaust streams from the incinerators with higher levels of inorganics will pose greater technical challenges than cleaner, hydrocarbon-only streams. SCR removal efficiency of 80% is a more reasonable design goal for dirty fuel streams. The incinerators with existing scrubbers would logically be good candidates for NO_x scrubber technology because of the potential avoidance of capital expenditure for a new scrubber as well as the operational experience in place with the scrubbers. The oxidation technologies appear capable of the 90% reductions envisioned by the proposed incinerator ESAD. However, developing technologies, like NO_x oxidation, are likely to have more unforeseen practical challenges compared to established technologies and these challenges can compromise performance goals. Because of the concerns raised by the commenters about inorganic materials in the exhaust streams, the commission has modified the ESAD for incinerators. The adopted ESAD for these units is either an 80% reduction from baseline, or 0.030 lb/MMBtu.

Safety-Kleen stated that because it is the only commercial hazardous waste incineration facility in HGA and the largest incinerator in HGA, the proposed rule "poses an unfair and extreme burden on this facility, the result of which will have a significant, adverse impact on the competitiveness of the facility in a small, highly-competitive marketplace." Safety-Kleen stated that by comparison, the other incineration facilities in the area only process smaller amounts of waste streams generated on-site, affording them a great deal more process control regarding NO_x formation. Safety-Kleen also expressed concern about potential increased "risk of harm to human health, safety, and the environment" associated with the transportation of hazardous waste to its distant competitors.

The commission does not believe that the rule will pose an unfair burden on Safety-Kleen. Safety-Kleen may be the only commercial hazardous waste incineration facility in HGA, but it is not the largest incinerator in HGA based on emissions or mass emission rate. The types of emission control that Safety-Kleen is likely to employ to reduce NO_x emissions will be post-combustion controls similar to other facilities in the area, referenced in the preceding responses to comments. Concerning potential increased "risk of harm to human health, safety, and the environment" associated with the transportation of hazardous waste to Safety-Kleen's distant competitors, the commission is addressing issues of cost and technical feasibility of compliance with the ESADs, rather than transportation issues. Consideration of any possible risks associated with transportation of hazardous wastes is beyond the scope of this rulemaking. As previously stated, in consideration of Safety-Kleen's and others' comments on the technical difficulties of reducing NO_x from dirty streams, the commission adopted a less stringent emission standard for incinerators.

TPIEC submitted a September 20, 2000 NCASI memo which stated that Kraft pulp mills collect their low volume high concentration (LVHC) non-condensible gases (NCG) and burn them in lime kilns, boilers, or stand-alone thermal oxidizers. The NCASI memo stated that the LVHCs are rich in TRS compounds and organics such as terpenes and methanol, and that low levels of NO_x emissions are feasible from the burning of these kraft pulping and evaporator NCGs in thermal oxidizers. The NCASI memo further stated that higher levels (from 5 to 46 lb/hr) have been measured in oxidizers that also burn stripper off-gases (SOGs) containing significant levels of ammonia, and that due to the high levels of SO_2 resulting from oxidation of the TRS compounds, most thermal oxidizers are equipped with a wet scrubber for SO_2 removal.

The NCASI memo stated that reduction of NO_x emissions by maximizing the principles of staged combustion, especially when ammonia-rich SOGs are burned, may be feasible, but that since the burning of SOGs in thermal oxidizers is in itself a fairly recent practice, efforts to bring this about are still in a fairly very exploratory stage and very well documented. The NCASI memo further stated that NO_x reduction by the use of SCR and SNCR technologies have also been reported in some Scandinavian mills, but their applicability to United States mill conditions remains uncertain. The NCASI memo stated that the requirement for a 90% NO_x reduction has no proven technological basis, and that due to the complexity of what causes NO_x to form in a thermal oxidizer, the floor representing uncontrolled NO_x emissions from thermal oxidizers has not yet been firmly established. The NCASI memo stated that the United States experience in bringing about high thermal oxidizer NO_x emissions reduction is limited, and that any requirement for NO_x emissions reduction from thermal oxidizers has to be determined on a case-by-case basis after satisfactory trials have been performed.

The commission adopted an alternate standard for incinerators based on an 80% reduction from 1997 levels, or 0.030 lb NO_x/MMBtu. The numerical emission standard will enable devices such as regenerative thermal oxidizers, which are inherently low-NO_x sources, to comply either without making reductions, or with small reductions.

BASF stated that the proposed emission specification penalizes incinerators that operated with a low NO_x emission rate in 1997. BASF also stated that the emission specification does not address incinerators that began operation or underwent a change in operation after 1997. BASF stated that NO_x emission increases may occur due to very high incinerator temperatures required to meet increasingly stringent VOC or HAP requirements for incinerators (MACT standards, BACT, etc.). BASF suggested that the emission specification for incinerators beginning operation after 1997 be the currently permitted emission factor. TCC stated that the commission should set an attainable standard for incinerators rather than a percent reduction.

The commission adopted an alternate standard for incinerators based on an 80% reduction from 1997 levels, or 0.030 lb NO_x/MMBtu. The numerical emission standard will enable newer sources which have been designed through combustion modifications as inherently low-NO_x sources, to comply either without making reductions, or with small reductions.

BASF stated that the reference to "fume abaters" in §117.206(c)(16) should be deleted and that vapor combustors, thermal oxidizers, and enclosed flares should be considered to be flares that are exempt from §117.206. TCC and Union Carbide submitted similar comments. BASF, Phillips 66, and TCC stated that the term "fume abater" is not consistent with the definition of "incinerator" in §101.1 and the use of "incinerator" in 30 TAC Chapter 115.

As discussed later in the *DEFINITIONS* section of this preamble, the commission identified incinerators (including enclosed control devices that combust or oxidize gases or vapors (e.g., vapor combustors and thermal oxidizers)) with more than 40 MMBtu/hr design heat input and BIF units as the largest NO_x emission sources within the category of waste combustion devices. Although the term "incinerator" is defined in §101.1 to refer to units which burn wastes for the primary purpose of reducing volume and weight, this term historically has also been used to refer to enclosed control devices that combust or oxidize gases or vapors, particularly in Chapter 115. The ESADs for incinerators apply to both types of units. Therefore, the commission has added a definition to §117.10 to clarify that for the purposes of Chapter 117, the term "incinerator" includes both enclosed control devices that combust or oxidize gases or vapors, and incinerators as defined in §101.1. The new definition is not a substantive change from how this term is intended to be used in Chapter 117, and its inclusion in the adopted rule will provide clarity. Subsequent definitions in §117.10 were renumbered due to the addition of the definition of "incinerator." Because "fume abaters" (meaning enclosed control devices that combust or oxidize gases or vapors (e.g., vapor combustors and thermal oxidizers)) are now clearly included in the new definition of "incinerator" in §117.10, the commission has replaced the reference to incinerators (including fume abaters)" with a reference to "incinerators" in §§117.201(12), 117.203(a)(4), and 117.206(c)(16).

Pasadena/Donohue stated that regenerative, recuperative, catalytic, and packed bed oxidizers are designed to operate at less than 2,000 degrees Fahrenheit and that thermal NO_x is not likely to be generated at this low temperature. Pasadena/Donohue also stated that these units typically burn natural gas only during start-up and to maintain the bed temperature. Pasadena/Donohue suggested that §117.203(a)(4)(A) be revised to exempt these units if they have a maximum design temperature greater than 2,000 degrees Fahrenheit.

The commission adopted an alternate standard for incinerators based on an 80% reduction from 1997 levels, or 0.030 lb NO_x/MMBtu. The numerical emission standard will enable devices such as regenerative thermal oxidizers, which are inherently low-NO_x sources, to comply either without making reductions, or with small reductions.

AMMONIA AND CO EMISSIONS

BCCA, Entergy, Equistar, ExxonMobil, and Lyondell asserted that the proposed rules were developed with a less than complete analysis of the possible environmental disbenefit of the proposed controls. BCCA, Dynegy, Entergy, Equistar, Goodyear, GPA, Lyondell, Phillips 66, TCC, TPIEC, TxOGA, and Union Carbide expressed concern about increases in ammonia emissions associated with SCR and SNCR. BCCA stated that if all combustion units greater than 40 MMBtu/hr used ammonia-based NO_x control technologies at an ammonia slip rate of ten ppm, ammonia emissions in HGA would increase approximately 31.5 tons per day and bring some of the HGA counties to the top of EPA's Toxic Release Inventory list for ammonia. TCC stated that ammonia is considered a more toxic and severe pollutant than NO_x. An individual expressed concern about possible increases in CO, VOC, and ammonia associated with post-combustion controls. BCCA estimated that ammonia usage in HGA will increase by 330 tpd under the proposed point source control strategy. BCCA, Dynegy, Entergy, Equistar, Goodyear, GPA, Lyondell, Phillips 66, TCC, TPIEC, TxOGA, Union Carbide, and Valero expressed concerns about safety of transportation, storage, and handling of ammonia. The commenters stated that before mandating the widespread use of ammonia-based NO_x control technologies, the commission should assess the overall regional risk of introducing new quantities of ammonia in HGA relative to the NO_x/ozone reduction benefit derived from the controls. TCC also stated that the commission should revisit the benefits of applying SCR to smaller facilities given the known adverse impacts of ammonia.

The commenter's estimate of 31.5 tpd of increased ammonia emissions is flawed by oversimplification and is not realistic. First, not all combustion sources greater than 40 MMBtu/hr will use ammonia-based NO_x control technologies. The capabilities of combustion modifications are well documented in the literature, including the NO_x control literature cited in this preamble as well as the rule cost note section of the rule proposal preamble. These documents report combustion based reductions from minimal to over 90%. Reduction capabilities as reported in the literature continue to improve. Theoretically, combustion modifications are capable of a 90% reduction, and in recent practice, a few low-NO_x burner retrofits in commercial operation are achieving this level. Use of combustion modifications will reduce the need for post-combustion controls in some cases. In addition, the ESADs for some source categories are based on use of combustion modifications. Finally, it is unrealistic to assume an across-the-board ammonia slip of ten ppmv. In reality, as noted later in this discussion, ammonia slip is reasonably expected to be no more than five ppmv on average. Therefore, the commenter's estimate of 31.5 tpd of increased ammonia emissions is overstated by at least a factor of two.

Control of the excess ammonia generation is a part of the art and the science, as well as the economics, of post-combustion controls which utilize urea or ammonia as a reagent. A competently designed and operated post-combustion control system will minimize excess ammonia generation. Minimizing ammonia slip from SCR 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 five ppmv. Thus, with good design, SCR can achieve ammonia slip values well below five 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 five ppmv ahead of the air preheater, which is a more challenging limit than an in-stack limit. The commission believes that issues related to ammonia release or concentration have been overcome through commercial development and experience in the last ten years. Ammonia slip emissions (and therefore subsequent particulate formation) in any case will be insignificant in comparison to other existing sources of ammonia in HGA, which are estimated to be 23,862 tpy (from area sources, on-road and non-road mobile sources, and biogenics. Existing emissions of ammonia from point source are estimated to be 1,802 tpy. Assuming ammonia slip at 5% (i.e., approximately 15 tpd) as a worst-case estimate from ammonia slip would result in a relatively modest increase in ammonia emissions of 20%. Due to the availability of the emissions cap and trade program and due to the ability of some Tier I controls to achieve the required reductions without the need for Tier II controls, the actual number of SCRs in operation are expected to be fewer than some commenters have suggested. Therefore, the actual ammonia emissions increase would be expected to be less than previously estimated.

The risks associated with anhydrous ammonia concern its asphyxiant and moderate combustibility properties. It is not classified as a hazardous air pollutant chemical and is lighter than air, so it dissipates readily. It is routinely handled by farmers and used in many industrial applications throughout the country. However, its asphyxiant and combustibility properties cannot be taken lightly. 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. Another approach, one that New Jersey follows, is to limit the quantity of anhydrous ammonia that may be stored, allowing a water solution with a maximum ammonia concentration of 26%, which reduces or eliminates concerns about accidental releases.

BCCA and TCC commented that if there is a significant quantity of unneutralized acids (e.g., sulfuric acid) in the atmosphere, then increases in ambient concentrations of ammonia will lead to increased particulate matter. BCCA stated that ambient particulate data collected across the Greater Houston area by the City of Houston, the TNRCC, and the Houston Regional Monitoring Corporation from March 1997 to March 1998 suggests that 10%-30% of the acids contained in ambient particulates are not neutralized. BCCA stated that consequently, particulate matter in the region is acidic, such that increasing ammonia concentrations have the potential to increase fine particulate matter ambient concentration in the form of ammonium sulfate. BCCA stated that in HGA, full neutralization of the sulfuric acid could lead to an increase in ambient fine particulate matter of 0.2 to 0.5 micrograms per cubic meter ($\mu g/m^3$). BCCA stated that it is also possible that the increased ammonia emissions might neutralize nitric acid, forming ammonium nitrate, which might add further to ambient particulate matter concentrations. BCCA commented that an increased mass of particulate matter in the atmosphere would drive the HGA closer to violating the pending NAAQS for fine particulate matter (i.e., particulate matter of less than 2.5 microns ($PM_{2.5}$)). BCCA stated that the commission should fully assess the benefits (e.g., lower ozone) and potential risk (e.g., higher particulates) of requiring NO_x control technologies that increase ammonia emissions. Fuel Tech commented that both NO_x and ammonia emissions contribute to fine particulate formation and stated that NO_x contributes to acid aerosol formation, while ammonia neutralizes atmospheric acidity. Fuel Tech commented that nitrogen is a biological fertilizer, irrespective of whether the nitrogen came from ammonia or NO_x emissions, and stated that the tradeoff between ammonia and NO_x emissions should favor the option that reduces the total amount of reduced and oxidized nitrogen. Sierra-Houston recommended that the allowable ammonia slip be five to seven ppmv, rather than ten ppmv, while Fuel Tech recommended that the allowable ammonia slip be 20 ppmv to reduce the required catalyst volume and associated capital cost. Fuel Tech stated that the additional ammonia emissions associated with higher (20 ppmv) ammonia slip is worth the additional NO_x reduction realized.

The commission selected an allowable ammonia slip of ten ppmv for post-combustion controls in order to balance the implementation of an effective control strategy for NO_x reduction against concern that significantly increased ammonia emissions will enhance $PM_{2.5}$ particle formation. Ammonia emissions can contribute to the production of particulate sulfate, nitrate, and ammonium which may create health effects concerns related to $PM_{2.5}$. These particulates can also degrade visibility. Current monitoring data indicate that additional ammonia emissions could increase particulate sulfate, and particulate nitrate and ammonium might also increase with a ten ppmv ammonia slip. However, the amount of any potential increase is uncertain, and until aerosol modeling is used to calculate $PM_{2.5}$ mass concentrations, the exact impact of increased ammonia emissions cannot be known. For that reason, the commission does not believe that increasing ammonia slip beyond ten ppmv is appropriate at this time.

TPIEC stated that no consideration appears to have been given to the potential impact of urea or ammonia slip with respect to deposition in local waterways as well as the Gulf of Mexico. TPIEC stated that unconverted ammonia/urea would be deposited in local areas and naturally converted to various nutrients, and that these nutrients could potentially impact the local watershed as well as the coastal ecosystem. TPIEC stated that the National Centers for Coastal Ocean Science's (NCCOS) *Gulf of Mexico Hypoxia Assessment* report indicates that nutrient loading issues are one of the major stresses to the coastal ecosystem in the Gulf of Mexico. TPIEC commented that an excerpt from the introduction of the report states: "Nutrient over-enrichment from anthropogenic sources is one of the major stresses impacting coastal ecosystems. Generally, excess nutrients lead to increased algal production and increased availability of organic carbon within an ecosystem, a process known as eutrophication. There are multiple sources of excessive nutrients in watersheds, both point and non-point, and the transport and delivery of these nutrients is a complex process, which is controlled by a range of factors. These include not only the chemistry, but also the ecology, hydrology, and geomorphology of the various portions of a watershed and that of the receiving system. Both the near-coastal hydrodynamics that generate water column stratification and the nutrients that fuel primary productivity contribute to the formation of hypoxic zones. Human activities on land can add excess nutrients to coastal areas or compromise the ability of ecosystems to remove nutrients either from the landscape or from the waterways themselves." TPIEC stated that the creation of additional nutrients from excess ammonia slip could also add to the top fifteen impairments cited in the Clean Water Act 303(d) list which will be used in the development of the total maximum daily loading (TMDL) criteria. TPIEC stated that of the fifteen impairments listed, nutrient loading, reduced dissolved oxygen issues, suspended solids, as well as the growth of noxious plants (algae) could all be adversely impacted by the increased nutrient loading created by the ammonia/urea slip and consequent nutrient loading issues.

The commission agrees that airborne emissions from nearby as well as distant sources contribute pollutant loadings to waters through atmospheric deposition. Logically, reductions in the emission rates of NO_x and ammonia would result in reduced deposition rates of inorganic nitrogen (e.g., NO_x, ammonia) to local waterways as well as the Gulf of Mexico. Indeed, in the Executive Summary for the EPA's *Deposition of Air Pollutants to the Great Waters--Third Report to Congress* (June 2000), the EPA noted that "actions taken by EPA and others to control sources of Great Waters pollutants of concern appear to have positively affected trends in pollutant concentrations measured in air, water, sediment, and biota." The EPA further stated that "pollutant emissions will be further controlled by several rules scheduled to take effect in coming years. As a result, atmospheric deposition and loadings of these pollutants (NO_x, etc.) may be significantly reduced." The EPA also noted that actions taken to "implement pollution control laws issued by States and other nations will further reduce pollutant loadings to the Great Waters." The ESADs will result in an estimated 595 tpd reduction in NO_x emissions (equivalent to 181 tpd of pure nitrogen), while generating perhaps 15 tpd of additional ammonia emissions (equivalent to 12.4 tpd of pure nitrogen). The resulting estimated 595 tpd reduction in NO_x emissions, coupled with the estimated 15 tpd increase in ammonia emissions, represents a significant reduction in inorganic nitrogen emissions (approximately 169 tpd of pure nitrogen) from NO_x point sources. This likewise represents a corresponding reduction in inorganic nitrogen deposition to local waterways and the Gulf of Mexico, thereby reducing the associated nitrogen nutrient loading.

Oceanographers have determined that nitrogen is the limiting nutrient in marine systems for algal growth (along with trace elements such as iron). The Gulf of Mexico hypoxia problem is linked to nitrogen loads to the Gulf along with periods of thermal stratification. In the Gulf Hypoxia study conducted by the National Oceanic and Atmospheric Administration (NOAA), (*NOAA Coastal Ocean Program Decision Analysis Series No. 17*, May 1999), the nitrogen budget to the Gulf of Mexico was estimated from all potential sources. Agricultural activities are the largest estimated nitrogen source with fertilizer and mineralized soil organic nitrogen contributing about 50%. Nitrogen sources such as groundwater discharge, soil erosion, and atmospheric deposition contribute about 24%. Animal manure contributes about 15%, and municipal and industrial sources add the remaining 11%. In contrast to results reported for Chesapeake Bay, atmospheric deposition of nitrogen appears to be a relatively small contributor to the total nitrogen load to the Gulf of Mexico. Atmospheric deposition of nitrate (wet and dry) in the upper Ohio River Basin watersheds (power plants) which is consequently washed into the river tributaries may be important to the overall delivery to the Gulf, and atmospheric deposition of ammonia from manure is higher in Iowa, Minnesota, and Illinois; however, the largest source is from commercial fertilizers in the Mississippi River and Ohio River watersheds. Direct atmospheric deposition of nitrogen to the Gulf of Mexico is estimated at less than 1.0% of the total nitrogen loading.

There are many estuaries around the Gulf (all of which are nitrogen limited) such as Galveston Bay, Sabine Lake, Matagorda Bay, and Upper and Lower Laguna Madre, for which atmospheric deposition is a larger percentage of the nitrogen load, and the direct deposition to these shallow bays is more than 1.0% of the load. The Mississippi numbers are not representative of these other systems. Nonetheless, the nitrogen load from direct deposition is small compared to the nitrogen load coming into these bays from indirect deposition to the watershed, mediation by the terrestrial ecosystem and flow into the estuaries. The estimated 169 tpd reduction in pure nitrogen emissions resulting from implementation of the ESADs will reduce the atmospheric nitrogen deposition to these ecosystems, thus improving their water quality.

Calpine and RMT questioned whether the CO and ammonia limits of §117.206(e) apply to stationary gas turbines with duct burners in their exhaust ducts. Calpine and RMT expressed concern that the definition of "boiler" in §117.10(6) could be construed to include duct burners in stationary gas turbine exhaust ducts.

The CO and ammonia limits apply to any NO_x source which is subject to a NO_x emission specification under §117.106 or §117.206, including duct burners in gas turbine exhausts. The commission notes that the applicable emission specification for duct burners is 0.015 lb NO_x/MMBtu. The commission has clarified the adopted rule language of §117.106(d) by changing "utility boiler" to "unit." This change will not impact any additional units in BPA and DFW because §117.106(a) and (b) only apply to utility boilers. The commission has likewise clarified the adopted rule language of §117.206(e) by changing "boiler or process heater" to "unit." This change will not impact any additional units in BPA because §117.206(a) only applies to boilers and process heaters in BPA. In DFW, §117.206(b) likewise already applies to boilers and process heaters, and therefore this change will not impact any boilers or process heaters in DFW. Although §117.206(b) also applies to gas-fired and gas/liquid-fired lean-burn stationary reciprocating IC engines in DFW, none of the three engines in DFW which are subject to §117.206(b) would have to comply with the ammonia limit because they can meet the emission limits using LEC modifications rather than post-combustion controls. Regarding the CO limits, the commission revised §117.206(e) to specifically exclude stationary IC engines in BPA and DFW because these engines are already subject to a CO limit in §117.205(e) and §117.206(b)(2), respectively. The commission revised §117.206(e)(1) by specifying a CO limit for IC engines in HGA that is consistent with these existing CO standards. The commission also revised §117.206(e) to specifically exclude BIF units and incinerators in HGA which are already subject to CO limits in other rules (for example, 40 CFR 266.102(e)(2)(ii)(A) and 40 CFR 266.104(b)). Finally, as discussed later in the *EXEMPTIONS* section of this preamble, the commission has excluded boilers and process heaters operating in "hot-standby" mode and lightweight aggregate kilns from correcting CO to 3.0% O_2, dry basis, because these units typically will operate with high excess O_2 which will drive the CO level, when corrected to 3.0% O_2, to a high level.

Calpine requested that §117.206(e) not be included as part of the SIP revision submitted to EPA because CO and ammonia are not required to be regulated for demonstration of compliance with the ozone standard. Chevron suggested that the CO limits be deleted because HGA currently meets the NAAQS for CO.

The adopted emission limits of §117.106(d) and §117.206(e) address pollutants which may increase as an incidental result of compliance with the adopted NO_x limits. The adopted CO limit is consistent with the existing CO limit of §117.105(i) and §117.205(f) because nothing in these rules necessitates changing the existing limit. The adopted ammonia limit of ten ppmv is lower than the existing limit of §117.105(j) and §117.205(g). The adopted ammonia limit is supported by information from SCR vendors and ammonia test data for gas-fired boilers using SCR, not available when the original NO_x RACT rules were adopted in 1993. The test data are reported in Table 2-5 of NESCAUM's *Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers* (June 1998). It is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The commission is not including these related pollutant limits in the attainment demonstration SIP in order to simplify the approval process for alternative emission specification under §117.121 and §117.221 and eliminate the need for case-specific SIP revisions to complete the approval of an alternate CO or ammonia limit. Therefore, approvals of an alternate CO or ammonia limit under §117.121 or §117.221 can be done without EPA involvement (i.e., no case-specific SIP revision needed) since the commission is not including these approvals in the attainment demonstration SIP. The commission has clarified §117.121(a) and §117.221(a) by adding references to §117.106(d) and §117.206(e), respectively.

REI stated that the CO limitation specified in §117.105(h) and §117.106(d)(1) should be revised to include the appropriate CO emission rates for oil- and coal-fired units. REI stated that the currently specified 0.30 lb/MMBtu limitation correctly characterizes CO emissions of 400 ppmv corrected to 3.0% O_2 from gas-fired units, but that due to different conversion factors, the appropriate values for oil- and coal-fired units are 0.31 lb/MMBtu and 0.33 lb/MMBtu, respectively.

It is standard practice in the field of air pollution control to reference concentration limits to a flue gas oxygen concentration, to address the effects of dilution. The commission notes that the suggested equivalent alternate standard based on heat input would simplify compliance tracking for monitoring systems which are based on carbon dioxide as the diluent. Therefore, the commission has revised §117.105(h) and §117.106(d)(1) accordingly.

PERMITTING

GEHC, HDHHS, Mothers for Clean Air, and 61 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 emission specifications. GHASP commented that all grandfathered facilities should be investigated to be certain that they are properly so designated since many of these facilities have made modifications. State Senator Carlos Truan commented that a problem with the proposed rules is that they do not deal with grandfathered facilities and that the commission has let these facilities avoid permitting through the use of standard exemptions.

The commission has made no change in response to the comments. The adopted rules that apply to facilities, for example the Chapter 117 NO_x requirements and the Chapter 115 VOC requirements, apply to both permitted and non-permitted ("grandfathered") sources in HGA. The commission agrees that it is appropriate to pursue cost-effective measures to reduce pollution; however, any such measures must be within the statutory authority of the commission. The TCAA does not authorize the commission to require grandfathered sources to obtain permits in order to operate, or to prohibit operation of those sources. A grandfathered facility is one that existed at the time the Texas Legislature amended the TCAA in 1971. These facilities were not required to comply with (i.e., were grandfathered from) the then-new requirement to obtain permits for construction activities. Whenever a grandfathered facility is modified (as that term is defined in the TCAA), it is required to comply with the TCAA permitting requirements in order to be authorized to construct and operate that modification. If a grandfathered facility has never been modified, it continues to be authorized by the TCAA to operate without a permit. Further, the definition of "modification" specifically excludes changes to facilities that are authorized by an exemption; i.e., any facility, including a grandfathered facility, can make a change using a commission exemption (now permit by rule) and this change is not considered to be a modification that would trigger the permitting requirements of the TCAA. During the 76th Texas Legislative Session in 1999, the issue of grandfathered sources was addressed by two different legislative programs. SB 766 was passed, which provided a framework for a voluntary permitting program for grandfathered sources under the TCAA, as well as SB 7, which requires mandatory permitting and emission reductions from EGFs. The commission continues to pursue enforcement action against companies who are not in compliance with the permitting requirements of the TCAA. However, SB 766 does provide for amnesty from enforcement for facilities eligible to participate in the voluntary emission reduction permit program as long as a permit application is received before the TCAA deadline of September 1, 2001.

An individual stated that the commission should publish the names of grandfathered sources and how much each emits.

The commission has already published the names of grandfathered sources and how much each emits. This information is available on the commission's website at: http://www.tnrcc.state.tx.us/air/care/eidata.html. Additional information concerning grandfathered sources and their emissions is available on the commission's website at: http://www.tnrcc.state.tx.us/grandfathered/index.html.

GEHC and eight individuals suggested a moratorium on issuance of NSR permits and/or plant expansions.

The mass emissions cap and trade program will cap the level of NO_x emitted from stationary sources in the HGA area, thus stopping the possible growth of emissions from any new sources. Any new source will be required to find and retire allowances equal to the amount of their actual NO_x emissions from sources already participating in the cap. Thus, this program does not limit growth, but it does limit growth of emissions. For reaching attainment with the ozone standard, controlling emissions is necessary, as opposed to limiting NSR permit issuance and/or plant expansions. Therefore, the commission disagrees with the commenters' suggestion and has made no change in response to the comment.

The EPA commented on the proposed exemption in §§117.103(d), 117.203(c), and 117.473 for combustion units which would meet the requirements of a standard permit currently being developed for electricity-generating combustion units rated at less than ten MW and which emit no more than 0.015 lb NO_x/MMBtu heat input. The EPA stated that in order for it to consider a source to be exempted from Chapter 117, the commission should submit the standard permit to the EPA for approval as a SIP revision because this essentially provides a procedure to obtain an alternate means of control. The EPA stated that as such, the alternate method must be part of the SIP. TXU supported the development of a standard permit for electricity-generating combustion units rated at less than ten MW, while Sierra-Houston stated that all sources with NO_x emissions of ten tpy or more should be subject to the ESADs.

Regarding the Sierra-Houston comment, the commission notes that a ten MW site at the 0.23 pound per MW-hour rate would only emit ten tpy if it operated for the full year, so any project exceeding ten tpy would have to obtain an NSR permit rather than the proposed standard permit. The commission notes that the NSR permitting requirements of Chapter 116 are part of the SIP and therefore are federally enforceable. The commission has changed "less than 10 MW" in §§117.103(d), 117.203(c), and 117.473 to "no more than 'ten MW' for consistency with the new standard permit for small electric generating units currently being developed. In addition, because the term "distributed generation of electricity" is not defined, the commission has replaced this term with the more descriptive wording "small (ten MW or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid." This exemption is intended to provide an incentive for installation and use of new clean energy-producing technology. The emission limit of the proposed standard permit is consistent with the adopted ESAD of 0.015 lb NO_x/MMBtu heat input.

BCCA, TCC, and Union Carbide expressed concern that the use of ammonia in post-combustion controls will trigger more complex permitting requirements due to increased ammonia emissions, and will likely increase the pre-construction lead-time. BCCA stated that this, in turn, shortens the total amount of time available to install the controls, resulting in more unscheduled equipment downtimes and economic burden to the region that must be considered in the selection of controls. BCCA encouraged the commission to consider and authorized these more complex permitting activities through the rulemaking process and not on a case-by-case basis. TCC requested confirmation that the installation of ammonia storage and handling facilities associated with SCR qualifies for Standard Permits for Pollution Control Projects authorized in 30 TAC §116.617.

The Standard Permit for Pollution Control Projects in 30 TAC §116.617 should be available for use by SCR projects, and the review time period is 30 days. The only additional requirement because of the ammonia would be a demonstration to the "satisfaction of the executive director" that there are no "significant health effects concerns resulting from an increase in emissions of any air contaminant other than those for which a National Ambient Air Quality Standard has been established." This requirement is in §116.617(1) and can normally be satisfied by using the EPA Screen Model. Using the standard permit should eliminate the increased permitting time referenced provided that the ammonia emissions from the storage, handling, and slip do not create any health concerns.

Solar Turbines stated that some turbines can only be retrofitted with dry low-NO_x systems after they are uprated as part of a major overhaul process and expressed concern that uprating could trigger NSR permitting requirements.

If "uprating" increases the unit's production capacity, then the owner or operator must satisfy the requirements of §116.617(5), which could require the owner or operator to not utilize the production capacity increase until the necessary authorization under §116.110 or §116.116 is obtained.

DEFINITIONS As described earlier in this preamble in the *TECHNICAL FEASIBILITY--AUXILIARY BOILERS* section, the commission has revised the definition of auxiliary steam boiler in §117.10(3) to clarify that an auxiliary steam boiler produces steam as a replacement for steam produced by another piece of equipment which is not operating due to planned or unplanned maintenance.

Phillips 66, TCC, and TxOGA commented on the proposed definition of "EGF" in §117.10(11). Phillips 66 and TxOGA stated that this definition appears to include cogeneration units and questioned whether this was the intent. Phillips 66, TCC, and TxOGA objected to the inclusion of cogeneration units. Phillips 66 and TxOGA recommended the definition be revised to include a percentage of "sales to the grid" and regulation by the PUCT as a threshold within the definition. TCC recommended that cogeneration units at petrochemical plants only be subjected to the mass emissions cap and trade program for consistency, ease of implementation, and clarity for operators.

The definition of EGF includes cogeneration units. Cogeneration turbines generate power which in some cases is sold to the grid and in other cases is entirely dedicated to use by a manufacturing process. Cogeneration units which normally provide power to the grid during periods of peak electric demand are adding NO_x emissions during times of higher probability of ozone exceedance. Therefore, these cogeneration units should comply with the daily cap. Cogeneration turbines which provide power to a dedicated industrial load may provide power to the grid only when the manufacturing process is not operating. This type of operation is not adding additional emissions during peak electric demand and ozone periods. The commission has modified the system cap requirements in §117.210 to exclude cogeneration units whose electric output entirely serves one or several dedicated industrial customers, except when the industrial customers are not operating. These sources are base load sources and are not operated at higher levels on hot summer days to meet electric demand and would not contribute additional emissions during these periods. Therefore, these sources are more similar to electric generating units located at an industrial site which do not generate electricity for compensation. Because these industrial electric generators do not provide electricity for peaking, they were never included in the system cap for the reasons described in the previous paragraph. In a future rulemaking, the commission may develop system cap trading rules for EGFs in HGA which would enable trades to occur among companies. This development would ensure the flexibility of cap and trade compliance.

KTC, Phillips 66, TCC, and TxOGA stated that a definition of "incinerator" should be added to §117.10 that is consistent with the definition of the existing definition in §101.1, or the commission should clarify that the use of this term in Chapter 117 is consistent with the definition in §101.1. KTC also suggested the addition of a definition of "thermal oxidizer" in §101.1. KTC, Phillips 66, TCC, and TxOGA stated that control devices such as vapor combustors and thermal oxidizers should be clearly unregulated by the proposed rules. Similarly, Phillips 66 and TxOGA stated that tail gas incinerators controlling sulfur recovery units (SRUs) are not incinerators as defined in §101.1, but are similar to flares. Phillips 66 and TxOGA requested clarification that tail gas incinerators controlling SRUs are part of the SRU and therefore unregulated by the proposed rules.

As discussed earlier in the *TECHNICAL FEASIBILITY--INCINERATORS* section of this preamble, the commission identified incinerators (including enclosed control devices that combust or oxidize gases or vapors (e.g., vapor combustors and thermal oxidizers)) with more than 40 MMBtu/hr design heat input and BIF units as the largest NO_x emission sources within the category of waste combustion devices. The commission confirms that tail gas incinerators controlling SRUs are part of the SRU and therefore are unregulated by the adopted rules. Although the term "incinerator" is defined in §101.1 to refer to units which burn wastes for the primary purpose of reducing volume and weight, this term has also been used to refer to enclosed control devices that combust or oxidize gases or vapors. The ESADs for incinerators apply to both types of units. Therefore, the commission has added a definition to §117.10 to clarify that for the purposes of Chapter 117, the term "incinerator" includes both enclosed control devices that combust or oxidize gases or vapors, and incinerators as defined in §101.1. The new definition is not a substantive change from how this term is intended to be used in Chapter 117, and its inclusion in the adopted rule will provide clarity. Subsequent definitions in §117.10 were renumbered due to the addition of the definition of "incinerator." Because "fume abaters" (meaning enclosed control devices that combust or oxidize gases or vapors (e.g., vapor combustors and thermal oxidizers)) are now clearly included in the new definition of "incinerator" in §117.10, the commission has replaced the reference to incinerators (including fume abaters)" with a reference to "incinerators" in §§117.201(12), 117.203(a)(4), and 117.206(c)(16).

Sierra-Houston commented on the definition of "low annual capacity factor boiler, process heater, or gas turbine supplemental waste heat recovery unit." Sierra-Houston stated that the heat input cutoff should be lowered to 1.0 (10^{11}) Btu per year. Sierra-Houston also commented on the definition of "low annual capacity factor stationary gas turbine or stationary internal combustion engine" and stated that the operating hours cutoff should be lowered from 850 to 500 hours per year.

The commenter is apparently suggesting these changes in the belief that these units are exempt from the ESADs for HGA. However, low annual capacity factor units at major stationary sources of NO_x in HGA are subject to the ESADs, and therefore the commenter's suggested changes would have no impact on these units. The commission has made no change in response to the comments.

Rhodia commented on the definition of "major source" in §117.10 and questioned whether NO_x emissions from exempt sources are included in determining a "major source" classification.

For HGA, the definition of "major source" includes any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit at least 25 tpy of NO_x. Therefore, NO_x emissions from all stationary sources or groups of sources are included in determining a "major source" classification.

TCC stated that a definition for "reheat furnace" should be added to the rule because some equipment, such as reboilers, could be considered a "reheat" furnace. TCC stated that the commission should clarify whether such equipment is considered a "reheat" furnace. Wyman-Gordon suggested that definitions of "heat treat furnace" and "reheat furnace" be added.

The commission agrees that definitions of "heat treat furnace" and "reheat furnace" are needed to clarify the units to which the rule applies, and has added definitions of these terms to §117.10 accordingly. The new definitions are not a substantive change from how these terms are intended to be used in Chapter 117, and their inclusion in the adopted rule will provide clarity. Subsequent definitions in §117.10 were renumbered due to the addition of the definitions of "heat treat furnace" and "reheat furnace." In addition, the commission changed "furnaces" to "metallurgical furnaces" in §117.206(c)(14) for additional clarity.

MISCELLANEOUS RULE LANGUAGE COMMENTS

Phillips 66 and TxOGA stated that the rule is poorly formatted and difficult to read and understand. In particular, Phillips 66 and TxOGA commented that the exceptions to some exemptions made the rule difficult to follow. Phillips 66 and TxOGA also stated that the proposed rule language contained a number of typographical errors and incorrect citations and equations.

Phillips 66 and TxOGA did not identify the specific errors in the proposed rule language. The commission has made every effort to eliminate errors and improve the readability of the rule.

TXU supported the addition of §117.105(l) which specifies that RACT limits will no longer apply after the emission specifications of §117.106 become applicable. TXU stated that this provision will avoid potential confusion and unnecessary overlap of rules when the more stringent requirements of §117.106 go into effect.

The commission appreciates the support. As a result of several changes to the rules as proposed, the schedule of reductions required by the adopted HGA mass emissions cap has been lengthened for a number of sources currently subject to the RACT limits. The language in §117.105(l) and §117.205(i) has been modified to specify that the RACT emission specifications are effective until the emissions allocation for a source under the HGA mass emissions cap are equal or less than the allocation that would be calculated using the RACT emission specifications.

Sierra-Houston stated that §117.107, concerning Alternative System-Wide Emission Specifications, should be repealed.

No changes were proposed to §117.107. Therefore, this comment is beyond the scope of this rulemaking. However, it should be noted that §117.106(e)(3) specifically prohibits use of §117.107 in HGA as an alternative method of compliance with the NO_x emission specifications of §117.106. Consequently, the suggested change is unnecessary in HGA.

TCC stated that the language in §117.206(d) and (f)(4) concerning NO_x averaging and compliance flexibility is confusing and should be revised.

The commission believes that the language of §117.206(d) and (f)(4) is relatively straightforward. Specifically, the owner or operator of affected units in HGA must use the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3, as opposed to complying on a rolling 30-day average or block one-hour average, as is the case in BPA and DFW. However, EGFs in HGA must also comply with the daily and 30-day system cap emission limitations of §117.210, which is modeled on the existing system cap in §117.108. Finally, an owner or operator in HGA may not use §§117.207, 117.223, and 117.570 to comply with the ESADs of §117.206(c).

TCC commented on §117.211 and stated that the initial demonstration of compliance is unnecessarily onerous, that the existing NO_x final control plans should have all the necessary data with the exception of exempt sources, and that consequently an initial demonstration of compliance should be required only for previously exempt sources.

For sources in the mass cap and trade program for HGA, the test requirements of §117.211 are used to determine emission factors for units not required to install a NO_x monitor. The ESADs will require most unmonitored sources to reduce emissions. For most sources, it will be to the owner's advantage to sample emissions after installation of control equipment in order to develop a lower emission factor for that source. However, to ensure that all emission factors are grounded on actual source measurement by the compliance deadline, all units must be tested at least once under §117.211 by December 31, 2006. It is possible that a few sources will be able to demonstrate compliance with the mass cap and trade program using an emission factor based on source testing developed for the November 1999 NO_x RACT final control plans.

TCC commented on §117.216(c) and stated that references to §117.520(a) and (b) should be to §117.520(a), (b), and (c).

The commission has revised §117.116 and §117.216 to exclude sources in HGA since the testing and monitoring of §117.114 and §117.214, in conjunction with the requirements of the mass emissions cap and trade program, will be sufficient to determine compliance. Therefore, the suggested change is unnecessary.

Union Carbide commented that §117.219(d) and the requirements of §§117.206(f), 117.213(k)(2), and 117.206(e)(1)(A) appear to be inconsistent. Union Carbide requested clarification of the actual data that is needed to demonstrate compliance. TCC suggested that §117.219 be revised to require "annual" rather than "semiannual" reporting frequency consistent with the NO_x mass cap and trade reports.

The excess emissions report is applicable for sources complying with specific emission limits, either NO_x RACT, the emission specifications for the BPA and DFW attainment demonstrations, or sources monitoring CO emissions under §117.206(e)(1)(A). The concept of excess NO_x emissions has been modified under the HGA cap and trade program and is now addressed in Chapter 101. Chapter 117 retains the emissions monitoring requirements for the HGA cap and trade program. Maintaining a semiannual report requirement, which identifies periods during which the monitoring system was inoperative and the nature of system repairs or adjustments, will help assure the effectiveness of the cap and trade program. The commission has reduced the semiannual report requirements of §117.219(d) for sources in the HGA mass emissions cap and trade program that are not subject to (or no longer subject to) §117.205 to a monitoring system report.

Union Carbide stated that the recordkeeping requirements in §117.219(f) should incorporate some data reduction measures that will allow for hourly data to be consolidated to a daily value for long-term storage similar to what is allowed under 40 CFR 63.152(f). Union Carbide stated that keeping hourly data for five years for each source can be burdensome.

Because §117.219(f) specifically allows the records to be electronic, the commission does not believe that the records are burdensome. The commission has clarified §117.219(f)(2) by adding a new subparagraph (C) for units subject to the mass emissions cap and trade program since compliance with the ESADs in HGA will be on an annual basis. However, EGFs subject to the system cap of §117.210 additionally will be required to keep daily records under §117.219(f)(2)(B). The commission may review the monitoring, reporting, and recordkeeping requirements for the HGA cap and trade program in the future. Some of the procedures in 40 CFR 163(f) could be considered at that time.

EMISSION SPECIFICATIONS--GENERAL

Sierra-Houston stated that the emission specifications for BPA in §117.106(a) and §117.206(a) should be made equivalent to those for HGA because HGA and BPA are adjacent to each other, need equivalent emission reductions, and contribute to each other's air pollution and that of DFW through transport.

No changes were proposed to the Chapter 117 NO_x limits for sources in BPA. Therefore, this comment is beyond the scope of this rulemaking. However, the commission may, in the future, develop additional control measures for BPA upon a determination that additional emission reductions are needed from BPA sources.

Pasadena/Donohue stated that §117.206(c) should be moved to a new section titled "Emission Factors for the Allocation of Allowances under the Mass Emissions Cap and Trade Program" to avoid any misinterpretation that these standards are to be met on a unit-by-unit basis.

The commenter's suggestion is a good one. However, the commission cannot make the suggested change due to APA requirements, which do not allow for the creation of a new section upon adoption of a rule proposal. Nevertheless, the commission believes it is clear that the ESADs in HGA are used to set the allocations for the mass emissions cap and trade program.

Calpine and RMT stated that the phrase "the lower of any applicable permit limit" in §117.206(c) should be removed for consistency with §101.353. Calpine and RMT stated that this is necessary to avoid penalizing those sources already emitting or authorized to emit at levels equal to or lower than the limits in §117.206(c).

A few new EGF permits for combined cycle gas turbine plants have been issued or are under review at 3.0 or 3.5 ppmv NO_x. These commitments have been made as part of the permit applications and have been relied on to enable the projects to meet the nonattainment new source review (NNSR) permitting requirements applicable in HGA. To allow the facilities a higher emission level under the cap and trade program would windfall those facilities with allowances and increase the overall levels of emissions in the cap. To hold these facilities to their emission commitments is not penalizing them. In addition, under the adopted cap and trade rules, these new facilities will not be required to buy in to the cap to operate. This approach serves to minimize the potential 23 tpd of NO_x emissions from new permitted sources that was not identified in the SIP proposal because this work was not completed by commission staff until after the rules were proposed in August. Minimizing this increase is an important element of achieving an approvable SIP for HGA. The commission has revised §101.353 to be consistent with Chapter 117 on this matter.

The EPA commented that the proposed language in §117.206(c) and §117.475(a) and (b) uses "the lower of any applicable permit limit or the emission limit" in Chapter 117. The EPA stated that if a source relies upon a permit, the commission must have issued that permit through a permit process approved by the EPA as part of the Texas SIP.

The commission notes that the NSR permitting requirements of Chapter 116 are part of the SIP and therefore are federally enforceable. In addition, permits by rule which are authorized by Chapter 106 are likewise federally enforceable. Specifically, "permit by rule" replaced "standard exemption" due to the requirements of SB 766, which amended the TCAA and created "permits by rule." Prior to passage of SB 766, the commission had the authority under TCAA, §382.057, to exempt from permitting requirements, changes within any facility and certain types of facilities that would not make a significant contribution of air contaminants to the atmosphere. In order to remove the appearance that these insignificant facilities were exempt from environmental regulation in addition to being exempt from permitting, the new TCAA, §382.05196 gives the commission the authority to adopt permits by rule for certain types of facilities that will not make a significant contribution of air contaminants to the atmosphere. On August 9, 2000, the commission adopted revisions to 30 TAC Chapter 106 in order to use permits by rule to authorize new construction and/or modifications or changes (25 TexReg 8653 (September 1, 2000)). On August 13, 1982, (47 Federal Register 35183), the EPA published its approval of several revisions to 30 TAC Chapter 116 that were submitted to the EPA for SIP approval on May 9, 1975. Part of that May 9, 1975 submittal included §116.6, Exemptions. Although §116.6 has since been revised, the version that existed at the time of the August 13, 1982 SIP approval has not been withdrawn from the SIP. Thus, the basic regulatory authority for exemptions, now permits by rule, is in the SIP. In a letter dated June 4, 1990 from Merrit Nicewander, Chief, New Source Review Section, EPA Region VI, to Lawrence Pewitt, Director of the Permits Division of the Texas Air Control Board (TACB, predecessor to the commission), the EPA stated that where the TACB issues standard exemptions pursuant to state regulations that were developed in accordance with the Texas SIP, the standard exemptions themselves are federally enforceable. Thus, since permits by rule are federally enforceable, companies may rely upon them in order to meet the requirements of §117.206(c) and §117.475(a) and (b).

TCC noted that §117.221 limits the alternative case specific specification to ammonia and carbon monoxide limits, and suggested that the rule be revised to allow companies to submit an alternative case specific specification for NO_x in §117.221. TCC stated that this is necessary due to the uncertainty associated with the proposed NO_x limits. Solutia and TCC stated that the regulated community needs a case-by-case determination for NO_x limits if they cannot demonstrate compliance despite best efforts and that the commission should address how they expect to handle such situations.

The commission does not believe that case-by-case determinations for NO_x limits are appropriate because the adopted Chapter 117 revisions include flexibility. Specifically, under the mass emissions cap and trade program, the agency will allocate to a source a number of allowances (NO_x emissions in tons) which a source would be allowed to emit during the calendar year. The source is not allowed to exceed this number of allowances granted unless they obtain additional allowances from another facility's surplus allowances. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet emission reduction requirements. The mix of control technologies can be greater because the owner can manage activity levels of equipment and place higher levels of control on high utilization units and less controls on less utilized units. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs.

SYSTEM CAPS

Dynegy stated that the daily and 30-day system cap limited the flexibility of the mass emissions cap and trade program. BCCA, Entergy, PECO, TCC, TIP, and TxOGA similarly objected to the daily and 30-day system cap. Phillips 66, TCC, and TxOGA suggested that EGFs whose primary purpose is to supply steam and electricity to an industrial facility be exempt from the daily and 30-day system cap and subject only to an annual limit. Calpine suggested that participation in the system cap of §117.210 be made voluntary for each "qualifying facility," as defined in 40 CFR 72.2, due to continual obligations to provide steam and electric power, which limits the ability to control activity level and take advantage of the system cap. Sierra-Houston objected to the proposed system cap and stated that system caps do not result in maximum NO_x reductions from every unit.

The commission disagrees with the comments and has made no change to the rules. The 30-day average emission limit functions as a flexible but controlling limit which ensures that a specified emission level is achieved during a typical peak ozone season day. The much less stringent daily maximum limit ensures that the 30-day average is not manipulated to allow higher NO_x emissions on a single day when ozone may be a problem. An annual limit cannot assure the level of control required on the hot summer days when ozone is most likely to form. For example, a cost effective compliance strategy with annual limits would be to import additional power and thereby reduce operations and emissions within HGA during the non-peak ozone season. Then, when meeting the peak electric demands of a hot summer day, the peaking units would be free to emit uncontrolled, adding to ozone levels. There would be a strong economic incentive to operate in this manner, because the peaking units include both the least efficient and oldest equipment, for which it is harder to justify adding emission controls. The system cap addresses the ozone problem while allowing the source owners to determine the most cost effective compliance strategy. For these reasons the commission has determined that the daily and monthly limits are necessary elements of the HGA SIP.

As described earlier in the *DEFINITIONS* section of this preamble, the commission has modified the system cap requirements in §117.210 to exclude cogeneration units whose electric output entirely serves one or several dedicated industrial customers, except when the industrial customers are not operating. These sources are base load sources and are not operated at higher levels on hot summer days to meet electric demand and would not contribute additional emissions during these periods. Therefore, these sources are more similar to electric generating units located at an industrial site which do not generate electricity for compensation. Because these industrial electric generators do not provide electricity for peaking, they were never included in the system cap for the reasons described in the previous paragraph.

The commission disagrees that these daily and monthly limits render the ability to trade meaningless because trading can still be useful to meet annual limits. As discussed in a previous response, in a future rulemaking, the commission may develop system cap trading rules for EGFs in HGA which would enable trades to occur among companies. This development would enhance the flexibility of cap and trade compliance.

REI commented that under §117.108(c)(1), a baseline heat input is proposed for calculation of a 30-day rolling average system cap using the "system highest 30-day heat input in the nine months of July, August, and September 1997, 1998, 1999." REI proposed that the phrase be changed to "*any* system 30-day heat input, *specified by an owner or operator*, in the nine months of July, August, and September 1997, 1998, 1999" to provide the flexibility for systems to choose a period other than that corresponding to the system highest heat input. (REI's emphasis supplied). Crown and TCC expressed concern about the use of the 1997-1999 period in the system caps of §117.108(c)(1) and §117.210(c)(1). Crown stated that this could limit throughput to the levels experienced in these years. Chevron suggested that the 30-day system cap be based on the highest six-month fired duty in 1995-2000. As an alternative, Chevron suggested that the average actual firing rates for units in non-turnaround months of the affected year be substituted for times that the unit is in a major scheduled shutdown or turnaround mode. PECO and an individual stated that the provisions for determining a 30-day system cap do not include a method for determining the system cap emissions for sources that did not operate between 1997 and 1999. PECO suggested that the following language be added to the H_i definition in §117.210(c)(1): "For EGFs constructed after January 1, 1999, authorized daily heat input may be used."

The 30-day system cap limit based on historical operations assures that reductions are achieved below actual historical levels. The years 1997-1999 were selected because use of the 1997 emissions inventory is consistent with the photochemical modeling analyses of NO_x point source emissions in support of the HGA ozone attainment demonstration, which are based on 1997 emissions. The system cap includes 1998 and 1999 to address concerns about fluctuations in activity level from year to year. The months of July, August, and September were selected because these three months typically represent the highest demand for electricity and, not coincidentally, include hot summer days when ozone is most likely to form. In summary, the baseline of the system highest 30-day heat input in the nine months of July, August, and September 1997, 1998, and 1999 represents recent highest utility electric demand and emissions during the peak ozone formation months. The commission agrees that the provisions for determining a 30-day system cap should include a method for determining the system cap emissions for sources which were not in operation prior to January 1, 1997. Consistent with the cap and trade provisions of §101.353(a), the commission has revised the H_i definition in §117.108(c)(1) and §117.210(c)(1) to address these sources in HGA.

Sierra-Houston commented on §117.108(i) and objected to allowing permanently retired or decommissioned EGFs to be used in a system cap emission limit. Sierra-Houston stated that this does not result in maximum NO_x reductions from every unit.

Only shutdowns that occurred after the modeled emission inventory are included in the system cap. This provides an incentive for the replacement of higher-emitting EGFs with much-cleaner EGFs, thus resulting in progress toward attainment of the ozone NAAQS. The commission has made no change in response to the comment.

EXEMPTIONS

BCCA, Calpine, NASA, PECO, REI, RMT, TGC, and TGP suggested that a new exemption be added for low annual capacity factor units. BCCA, NASA, Pasadena/Donohue, PECO, REI, and TGP stated that the retrofit of combustion controls and SCR is not economically reasonable for certain low-capacity factor applications. BCCA and REI stated that a number of local air districts in Southern California have regulations which allow for lesser NO_x control requirements for gas turbines with limited operation, and that the commission should consider the approach used in SCAQMD Rule 1134 which recognizes retrofit consideration issues associated with gas turbines of different sizes and applications. BCCA stated that SCAQMD exempts low capacity factor turbines, laboratory gas turbines used in research and testing, gas turbines operated exclusively for fire fighting and/or flood control, chemical processing gas turbines, emergency standby and peaking gas turbines demonstrated to operate less than 200 hours per calendar year, existing gas turbines rated below 4.0 MW and operated less than 877 hours per year, etc.

The commission has evaluated the comments and has included exemptions in the adopted rules for certain sources in HGA which provide for a balance between the need for NO_x reductions and implementation of an effective, technically feasible control strategy. As described earlier in this preamble in the *TECHNICAL FEASIBILITY--AUXILIARY BOILERS* section, the commission has added an alternative ESAD as new §117.106(c)(4) based on Tier I controls. The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for auxiliary boilers, utility boilers, and stationary gas turbines with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation.

Regarding IC engines, the commission has added a new paragraph (10) to §117.203(a) which exempts diesel-fired engines. This will address emergency diesel-fired generators. The commission notes that §117.203(a)(6)(A) exempts stationary gas turbines and engines which are used in research and testing, or used for purposes of performance verification and testing, or used solely to power other engines or gas turbines during start-ups, or operated exclusively for firefighting and/or flood control, or used in response to and during the existence of any officially declared disaster or state of emergency, or used directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals, or used as chemical processing gas turbines. However, in the future, the commission may pursue requirements for these currently-exempt engines in HGA to prevent emissions increases from these engines if operated in peak shaving mode, or to address their emissions if additional reductions are determined to be necessary to reach attainment with the ozone NAAQS.

The commission has also added new §117.206(c)(17) and §117.475(c)(3), which provide low annual capacity factor units with an alternative to the emission specifications in §117.206(c)(1)-(16). The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation. This alternative ESAD will address low-capacity factor applications which do not qualify for the stationary gas turbine and engine exemptions described in the previous paragraph.

TCC and Union Carbide stated that the 850 hour per year exemption should be retained rather than eliminated. Phillips 66 and TxOGA stated that the 850 hour per year exemption for stationary IC engines should be reduced to 250 hours per year, while Texas Eastern suggested a cutoff of 200 hours per year. Sierra-Houston stated that the 850 hour per year exemption should be reduced to 500 hours per year and that only stationary IC engines of less than 100 hp should be exempt. Pasadena/Donohue suggested that the 850 hour per year exemption be retained and that only stationary IC engines of less than 250 hp be exempt. Pasadena/Donohue also suggested that an exemption be added for engines which are operated during maintenance and repair activities. Texas Eastern, TGC, and TGP stated that compliance with the 0.17 g/hp-hr NO_x emission specification on engines with low utilization rates or lower emission rates during the baseline years will result in large capital expenditures with minimal NO_x reductions. Dynegy and Pasadena/Donohue suggested the inclusion of an exemption from the emission specifications and monitoring requirements for emergency generators which are used solely in the event of a power outage. Pasadena/Donohue stated that it has an engine which must be used during power outages to rotate a lime kiln to keep the hot lime from warping the bottom of the kiln. Phillips 66, Spring Valley, TCC, Texas Eastern, and an individual stated that firewater pumps and emergency electrical generators are used only a small portion of the time, and therefore the emissions will only be a small portion of the total potential emissions and should be exempt. TCC stated that companies must maintain the reliability of emergency equipment designed for use in the event of a catastrophic incident and that reliable, voluntary testing of emergency back-up or standby equipment should be encouraged rather than discouraged. Spring Valley and an individual suggested that testing of engines should be restricted from operating between 6:00 a.m. and noon. TCC also stated that the commission should clarify that testing of emergency equipment is already exempt per §117.203(a)(6)(A) and the potential loss of the 850 hour per year exemption in no way impacts the testing of this equipment. In addition, TCC stated that the commission should also clarify that the exemption applies to gas turbines, engines, and other infrequently used equipment, and that these sources also should be exempt from continuous monitoring requirements. GPA and Solar Turbines recommended an exemption for gas turbines rated at less than ten MW. Solar Turbines also suggested the inclusion of a dollars per ton exemption threshold, to be set no higher than that found acceptable under NO_x RACT rules or that used in developing NO_x SIP rules. Spring Valley and an individual suggested that engines that are exempt from the Chapter 117 requirements be subject to the California spark-ignition engine requirements of §114.421 and §114.422.

As noted earlier in this preamble, the commission has added exemptions for certain stationary gas turbines and engines. Section 117.203(a) specifically states that units which qualify for exemption under this subsection are "exempted from the provisions of this division," which includes the CEMS and PEMS requirements. As noted earlier in this preamble, the commission has added a new §117.206(c)(17), which provides low annual capacity factor units with an alternative to the emission specifications in §117.206(c)(1)-(16), and has also added an additional ESAD to §117.106(c)(2) for auxiliary boilers, utility boilers, and stationary gas turbines based on Tier I controls. In the future, the commission may pursue emission reductions from exempt sources in HGA if additional reductions are determined to be necessary to reach attainment with the ozone NAAQS. Similarly, the commission may pursue in future rulemaking the suggestion that testing of the engines should be restricted from operating between 6:00 a.m. and noon.

The commission disagrees with the suggested concept of including a maximum cost (in dollars per ton of NO_x reduced) in the 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.

TECO commented on the proposed emission specification for dual-fuel engines in §117.206(c)(9)(C) and stated that it operates a 6.0 MW dual-fuel engine/generator unit to provide electricity during times of reduced reliability of the REI commercial power grid. TECO stated that the engine has operated from 219 to 444 hours per year in 1997-1999 and that it would cost $111,877 per ton to add SCR to this engine and might render the unfired waste heat recovery boiler inoperable. TECO stated that its dual-fuel engine/generator furnishes electricity to a variety of medical buildings, and that future growth could result in the building owners installing individual engines which would produce less than ten tpy and therefore would not be subject to the proposed Chapter 101 mass emissions cap and trade program. TECO stated that these individual engines would produce 6.0-8.0 g/hp-hr of NO_x, resulting in greater emissions compared to its one large engine. TECO suggested that an exemption be added to §117.203 for dual-fuel engines at "District Energy Plants" which run less than 850 hours per year.

Engines which are used to shave peak electric demand tend to operate on hot days that coincide with higher probability of ozone exceedances. The commission does not agree with the suggestion to exclude this source from the cap and trade program entirely. Uncontrolled, the 8,338 hp engine has the potential to emit 1.3 tpd of NO_x, but under the cap and trade program, the low historical usage of this engine would limit the NO_x emissions, regardless of the emission specification. The reported NO_x emissions for the engine were 11.3 tpy over the year in 1997, and 0.018 tpd over the June-August, 1997 period used in the attainment demonstration modeling.

The commission has adopted two standards for dual-fuel engines. The adopted ESAD of 0.5 g/hp-hr would apply to any dual-fuel engine placed into service after December 31, 2000. The adopted 5.83 g/hp-hr ESAD would apply to engines that were placed into service before December 31, 2000. The TECO engine, the only dual-fuel stationary engine in the HGA point source inventory, would be subject to the 5.83 g/hp-hr standard, which is the emission factor used to calculate TECO's emissions in 1997. This results in the TECO engine being included in the cap and trade compliance program at its historical emission factor and activity level, so it will not be required to reduce emissions, but it will not be given allowances to increase them, either. By capping the emissions at this level and requiring TECO to find other ways to reduce emissions if the engine is to increase its emissions, the source, which contributes to ozone exceedances, is also required to be part of the attainment strategy.

It has come to the commission's attention that the proposed §117.103(a)(2) inadvertently included a comma after the term "utility boiler" that should have been deleted when the term "steam generator" was deleted. The commission has revised §117.103(a)(2) to remove this comma.

TXU supported the proposed revision to §117.103(c)(1) which would extend the oil-fired emergency exemption provisions of §117.105 to the emissions specifications of §117.106 and §117.108 for EGFs. TXU stated that this provision will help maintain electric reliability during critical periods of gas supply interruption. NASA and TCC stated that a similar exemption should be added to §117.203 to suspend fuel oil firing emission specifications for industrial boilers, process heaters, and furnaces during these same emergency operating conditions.

The commission agrees with TXU that the purpose of the oil-fired emergency exemption provisions of §117.103(c)(1) is to help maintain electric reliability during critical periods of gas supply interruption. Gas curtailments are most likely to occur during extended periods of sub-freezing weather, and it is important during such times to maintain the reliability of the electric grid to ensure that human health is not endangered by lack of heat due to unavailability of electricity. There is no corresponding need during these same emergency operating conditions for industrial boilers, process heaters, and furnaces to continue operating. Therefore, the commission disagrees with NASA and TCC and has made no change in response to the comments.

Solutia and TCC suggested that addition of an exemption in §117.203 for startup or regeneration heaters operated less than 850 hours per year. Solutia and TCC stated that this equipment is used only a small portion of the time, and therefore, the emissions will only be a small portion of the total potential emissions. As an example, Solutia and TCC stated that process startup heaters used to preheat systems prior to introducing feeds operate for a short period of time for a startup which generally occurs a few times a year. Solutia stated that it has five startup heaters ranging in size from 11 to 75 MMBtu/hr heat input, each operating less than 850 hours per year.

As noted earlier in this preamble, the commission added a new §117.206(c)(17), which provides low annual capacity factor units with an alternative to the emission specifications in §117.206(c)(1)-(16). The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation.

Chevron suggested that the exemption in §117.203(a)(9) for boilers and process heaters be revised from 2.0 MMBtu/hr to ten MMBtu/hr due to the high cost of FGR and SCR in these small units. Chevron also questioned the feasibility of installing SCR and FGR on these units. TCC suggested that the exemption be revised to 15 MMBtu/hr, or alternatively, that all boilers and process heaters rated at less than 40 MMBtu/hr should be exempt because these sources make up a large percentage of total units but a small percentage of total NO_x emissions.

Currently, boilers and process heaters rated at less than 2.0 MMBtu/hr are regulated under Chapter 117. The commenters' suggested changes would result in a gap in coverage for some or all boilers and process heaters between 2.0 and 40 MMBtu/hr. The boilers and process heaters in HGA are almost entirely gas-fired. FGR has been demonstrated to be an effective control technology for these sources, based on experience with BACT NO_x limits, retrofit requirements in California, and information in the literature. Fuel trim has been demonstrated as an effective control technique for natural gas fired boilers operating with FGR to achieve compliance with a 30 ppmv NO_x limit. The combination of FGR to achieve NO_x compliance with variable speed fans and upgraded boiler operating controls has improved fuel efficiency and combustion stability. The commission has made no change in response to the comments.

It has come to the commission's attention that the exemption for ICI boilers and process heaters with a maximum rated capacity of less than 40 MMBtu/hr in the proposed §117.205(h)(9) is unnecessary because these units are already exempt under the existing §117.205(h)(1). Therefore, the commission has deleted the proposed §117.205(h)(9) and renumbered the proposed §117.205(h)(10) and (11) as §117.205(h)(9) and (10). The commission has also revised references to these rules in §117.213 to reflect their renumbering.

TCC and Union Carbide stated that §117.206(c)(1)(C) and (8)(C) should be revised to exclude boilers and process heaters with a maximum rated capacity of 2.0 MMBtu/hr or less.

An exemption has been added for these small boilers and process heaters as new §117.203(a)(9). Therefore, the suggested change does not appear to be necessary.

Phillips 66, TCC, and TxOGA suggested the addition of an exemption from the CO limits for boilers operated in hot-standby mode, as indicated by low load and high stack oxygen concentration (greater than 15% O_2). Phillips 66 and TxOGA considered "low load" to be less than 1.0% of maximum, while TCC considered "low load" to be less than 5.0% of maximum. TCC stated that combustion sources such as boilers, process heaters, and pyrolysis furnaces equipped with multiple low-NO_x burners have difficulty meeting the Chapter 117 CO emissions limit during periods of hot-standby operation. TCC stated that hot-standby operations are those periods during which only a very few burners are in operation, when fired duty may be as low as 1.0-5.0%. TCC stated that during periods of hot-standby, stack oxygen is nearly always over 15%, and averages about 20%. TCC stated that the uncorrected CO concentration averages about 35-75 ppm for some boilers, and as low as 0.5 to 8 ppm for some furnaces, and that the CO concentration corrected to 3% O_2 may average from over 300 ppm to over 600 ppm. Solutia similarly suggested an exemption or revised emission standard for such boilers. TXI stated that 15% O_2 is typical in lightweight aggregate kiln stack emissions. TXI commented that EPA MACT regulations specify 7.0% O_2 in stack emissions from hazardous waste kilns, and stated that use of a 3.0% O_2 level to correct CO emissions from lightweight aggregate kilns would be unreasonable.

The commission agrees that certain units typically will operate with high excess O_2 which will drive the CO level, when corrected to 3.0% O_2, to a high level. These units include boilers and process heaters operating at less than 10% of maximum load with stack O_2 in excess of 15% (i.e., "hot-standby" mode), and lightweight aggregate kilns. Accordingly, the commission has revised §117.206(e) to exclude these units from correcting CO to 3.0% O_2. Other units which were excluded from the CO limit of §117.206(e) if they are already subject to CO limits in other rules include stationary IC engines in BPA and DFW, BIF units, and certain incinerators, as described in the *AMMONIA AND CO EMISSIONS* section of this preamble. It should be noted that approvals of an alternate CO limit are available under §117.221 and can be done without EPA involvement (i.e., no case-specific SIP revision needed) since the commission is not including these approvals in the attainment demonstration SIP.

Dynegy suggested the addition of an exemption for major sources to be modeled after the exemptions for minor sources in the proposed §117.473(a)(2)(A) and (b).

The exemption available for minor sources in §117.473(b) does not apply to sources which are subject to the mass emissions cap and trade program. Since all major sources are subject to the mass emissions cap and trade program, it would be inappropriate for the exemption available for minor sources in §117.473(b) to also apply major sources. Regarding the exemption available for minor sources in §117.473(a)(2)(A) for engines rated at 50 hp or less, the commission has not included a similar exemption in §117.203 for major sources in order to ensure that the universe of equipment outside the cap at major sources is minimized. This is necessary to achieve NO_x reductions which come as close as possible to the 90% target described earlier in this preamble. Nevertheless, as noted earlier in this preamble, the commission added a new §117.206(c)(17), which provides low annual capacity factor units with an alternative to the emission specifications in §117.206(c)(1)-(16). The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation.

Calpine and RMT stated that a new §117.206(h) should be added to provide an exemption from §117.206(c) for sources in HGA that emit less than ten tpy units in order to mesh with the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3.

The applicability of §117.206(c) is specified in §117.201, which states that Subchapter B, Division 3 (Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) applies to the listed units "located at any major source of nitrogen oxides" in BPA, DFW, or HGA. For HGA, "major source" is defined in §117.10 as any stationary source or group of sources located within a contiguous area and under common control that emits or has the potential to emit at least 25 tpy of NO_x. Sources that emit less than 25 tpy of NO_x are regulated under Chapter 117, Subchapter D, concerning Small Combustion Sources. Section 117.475 spells out the two compliance approaches available for sources which emit less than ten tpy, either direct compliance with the emission specifications, or compliance through the mass emissions cap and trade program in Chapter 101.

TGP commented that under §117.475(c)(2), stationary IC engines greater than 50 hp would have to meet an emission specification of 0.50 g/hp-hr. TGP stated that there may be more than 1,000 emergency generators, located at most office buildings, high-rise residences, country clubs and hotels, that would have to meet this emission specification. TGP stated that emergency generators usually do not operate more than 100 hours per year and recommended the addition of an exemption under §117.473(a)(2)(H) for "portable and emergency engines and turbines as defined under §106.511."

The emission standard for stationary reciprocating IC engines is intended to apply only to gas-fired engines. The commission has added "gas-fired" to §117.475(c)(2) to clarify this standard and has added a new subparagraph (I) to §117.473(a)(2) which exempts diesel-fired engines. The commission agrees that an exemption for gas-fired emergency generators is appropriate and has revised §117.473(a)(2) accordingly to include an exemption for emergency generators that do not operate more than 100 hours per year. The commission has added a new subsection (h) to §117.479 which specifies the recordkeeping requirements for engines which are necessary to document exemption status. However, in the future, the commission may pursue requirements for these engines to prevent emissions increases if they are operated in peak shaving mode, or to address their emissions if additional reductions are determined to be necessary to reach attainment with the ozone NAAQS.

As noted earlier in this preamble, the commission added a new §117.475(c)(3), which provides low annual capacity factor units with an alternative emission specifications. The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for units with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation.

MONITORING REQUIREMENTS

Two individuals suggested that continuous monitoring of emissions be required. One of the individuals suggested that the results be published in the newspapers. Another individual suggested that CEMS/PEMS data be transmitted directly to TNRCC regional offices.

The adopted rules include requirements for continuous monitoring systems (CEMS or PEMS). Emissions data is submitted to the commission, and therefore is a public record available to the public for review. Therefore, the commission does not believe it is necessary to require the regulated community to publish emissions data in the newspaper. It is impractical to require that CEMS/PEMS data be transmitted directly to TNRCC regional offices because the commission has the authority to request monitoring information at any time, and therefore simply accumulating duplicate data in the regional office would serve no useful purpose.

Kinder Morgan and TGP commented on periodic testing for emergency generators and other low capacity factor units in §117.214(a)(1) and §117.213(g). Kinder Morgan and TGP suggested the inclusion of an exemption that would only require testing of low annual capacity factor units in cases of installing controls, after performing major maintenance, permit renewals, or in cases where the operator or agency believes the emissions may have changed. Kinder Morgan and TGP's suggested language would not require periodic emission testing for engines run no more than ten hours per month. Enron suggested that low annual capacity factor engines not be required to conduct periodic emission testing, except after installation of controls, major repair work, or when the owner/operator believes that emissions may have changed. Pasadena/Donohue likewise suggested that low annual capacity factor engines not be required to conduct periodic emission testing, and stated that testing would result in more emissions than actual operation of its auxiliary engine during power outages.

The commission has corrected a reference in §117.214(a)(1) to §117.213(g) and has revised §117.213(g) by adding a new paragraph (2) to specify an alternative to periodic testing for engines which use a chemical reagent for reduction of NO_x. Since these engines are required under §117.213(c)(1)(E) to be equipped with NO_x CEMS or PEMS, there is no need for these engines to conduct periodic testing. Therefore, the commission has subdivided §117.213(g) into requirements for engines with and without CEMS/PEMS, and has added a new paragraph (2) which specifies that engines which use a chemical reagent for reduction of NO_x shall comply with the with NO_x CEMS or PEMS requirements rather than conduct periodic testing.

Regarding low annual capacity factor engines, the commission notes that §117.213(g) applies to engines which are subject to an emission specification. Because the commission has added a new paragraph (10) to §117.203(a) which exempts diesel-fired engines, these engines will not be required to conduct testing under §117.213(g). However, gas-fired emergency generators are subject to the ESADs. The commission has revised §117.213(g) by adding a new paragraph (1)(C) for which specifies that gas-fired emergency generators are not required to conduct periodic testing under the renumbered §117.213(g)(1)(B).

The commission has revised §117.208(d) to exclude sources subject to §117.206(c) and has concurrently added a quarterly engine testing requirement as new §117.214(b)(2). Because quarterly emission testing for engines that run no more than ten hours per month could result in these engines operating when they otherwise would be idle, thereby increasing emissions, the commission has included language which states that quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours. This exemption does not diminish the requirement to test emissions after the installation of controls, major repair work, and any time the owner or operator believes emissions may have changed.

BP, Phillips 66, TCC, and TxOGA suggested that the CEMS/PEMS requirements should be limited to units being controlled by SCR, rather than basing the CEMS/PEMS requirements on heat input. As an alternative to CEMS/PEMS monitoring, Dynegy suggested that monitoring be performed quarterly with a portable gas analyzer (or equivalent methodology) and whenever maintenance activities may affect the NO_x emissions. TCC stated that the heat input threshold for CEMS/PEMS requirements should be 250 MMBtu/hr for boilers and 200 MMBtu/hr for process heaters, rather than 100 MMBtu/hr for these sources. TGP stated that the CEMS/PEMS requirements for IC engines is overly burdensome and that even if an IC engine is converted to electric, the current language in §117.213(c)(2)(A) mandates a CEMS or PEMS.

NO_x monitors will be key to a successful point source emission reduction program and is critical to achieving real reductions in NO_x emissions which are necessary to attain the ozone NAAQS. Without CEMS/PEMS, estimating NO_x emissions is subjective. NO_x is a product of a dynamic reaction in a flame, and can easily vary tenfold in a brief time. Units controlled by combustion modification are not immune to variability in NO_x emissions. By basing the monitoring requirements on size of equipment (heat input), the commission does not discriminate between control technologies while ensuring that the greater portion of the point source NO_x in HGA will be reduced to the required specifications. The monitoring suggested by Dynegy may be more appropriate for sources not required to install NO_x monitors under the adopted rule. The language in 117.213(c)(2) is a list of NO_x sources not required to install a CEMS or PEMS under §117.213. An electric motor is not listed because it is not a NO_x source.

TCC stated that flexible monitoring and recordkeeping methods are appropriate for SCR. TCC stated that actual ammonia levels should be determined based on a stoichiometric material balance and actual material use, rather than through the use of monitors. TCC stated that additional continuous monitoring devices increase labor, material, and maintenance costs, and do not reduce emissions in and of themselves.

The CEMS/PEMS requirements are for the monitoring of NO_x, CO, and either O_2 or CO_2. Ammonia slip emissions do not rise to a level of concern that would justify requiring continuous monitors for ammonia.

Pavilion requested confirmation that PEMS are allowed as an alternative to CEMS.

The commission confirms that PEMS are specifically allowed as an alternative to CEMS under §117.213(c)(1).

Pavilion stated that the commission should adopt some form of the TNRCC PEMS Draft Protocol as part of the rule in order to clarify the PEMS requirements and agency policies to the regulated community and the TNRCC's field operations and enforcement groups.

The TNRCC PEMS Draft Protocol is available to the regulated community as well as enforcement personnel in order to clarify the PEMS requirements for both regulations and for NSR permits. Therefore, the commission does not believe that it is necessary to adopt this guidance as a rule.

Pavilion stated that all units should be required to implement advanced process monitoring and control schemes as part of standard operating procedures of control devices. Pavilion stated that advanced process monitoring can detect if a unit and/or add-on control device is malfunctioning, thereby reducing pollution on a consistent basis, minimizing reagent usage and reagent slip, and decreasing the operating costs necessary to comply with the rule.

Monitoring to determine the instantaneous NO_x level is useful in allowing tight process control and rapid corrective actions to reduce NO_x emissions. The adopted rules include appropriate emission monitoring requirements.

Pasadena/Donohue commented on the CEMS requirements of §117.213(e)(3)(A) and stated that the requirement to analyze separately the exhaust stream of each unit sharing a CEMS should be revised to provide an exception for units in the mass cap and trade program since the purpose is to monitor and document actual NO_x emissions for deduction from allowance accounts on an annual basis. Pasadena/Donohue stated that similar language should be added to the PEMS requirements of §117.213(f).

Under §117.213(e)(3), several units, each venting to a single stack, can share a single CEMS, thereby reducing the monitoring costs. The requirement to analyze separately the exhaust stream does not apply to the case of several units venting to a common stack, which is not the case addressed by subsection (e)(3). The cap and trade program is concerned only with total emissions to the atmosphere, so monitoring combined emissions in a single stack is at least as effective an enforcement approach as monitoring separate streams. It is also simpler and more cost effective than monitoring separate streams. In contrast to a CEMS, which measures the gaseous concentration of a pollutant, a PEMS predicts pollutant emissions and does not directly measure the gaseous concentration. Some PEMS rely on physical principles which employs analytical methods to describe the dynamics of the process. These methods are derived from the physical equations or the laws of nature that govern the system. This category of models is typically expressed in nonlinear partial differential equations that are solved via numerical analysis techniques, as these equations are often too complicated to be solved via standard analytical methods. Other PEMS rely mainly on computer software which, with the use of high quality historical data, interpolates and/or extrapolates over a wider range of operating conditions, or learns the dynamics of the process by developing statistical multi-variable mathematical functions that mask the dynamics of the process. Since a PEMS is necessarily dependent on the process, it is not appropriate to extend the CEMS flexibility of §117.213(e)(3) to PEMS.

Sierra-Houston commented on §§117.114(c)(2)(B), 117.214(c)(2)(B), and 117.479(e)(7)(B) and noted that retesting must occur within 60 days after any modification which could reasonably be expected to increase the NO_x emission rate. Sierra-Houston objected to the retesting being optional after any modification which could reasonably be expected to decrease the NO_x emission rate.

The commission disagrees with the commenter. While it is important for retesting to occur if the emission rate could have increased to ensure that the emission reduction requirements are still being met, it is not important for retesting to occur if the emission rate decreased. The owner or operator may choose to conduct retesting after any modification which could decrease the NO_x emission rate since the emission reduction requirements logically would continue to be met after an emissions decrease.

The EPA commented on §117.478(b)(5), concerning the requirement for checking the proper operation of an IC engine after maintenance that might be reasonably expected to increase emissions. The EPA stated that the term "as soon as practicable" is vague and makes enforcement for violations of proper operating procedures very difficult and perhaps impossible. The EPA suggested that a specific time limit such as two weeks could be set for when to check the operation of the engine after maintenance.

The commission agrees and has revised §117.478(b)(5) accordingly.

Union Carbide stated that §117.520(c)(2)(D) has a conflict with §117.520(c)(2)(E) and §117.211 concerning when the first relative accuracy test audit (RATA) is due. Union Carbide requested clarification of when the initial RATA and demonstration of compliance have to be completed and when the initial demonstration of compliance report has to be submitted.

The commission has revised §117.510(c)(2) and §117.520(c)(2) to specify that the applicable CEMS or PEMS performance evaluation and quality assurance procedures must be submitted within 60 days after startup of a unit following installation of emission controls, or by March 31, 2005, whichever comes first. An initial demonstration of compliance report is not required. Also, as described earlier in this preamble, the commission revised §117.116 and §117.216 to exclude sources in HGA since the testing and monitoring of §117.114 and §117.214, in conjunction with the requirements of the mass emissions cap and trade program, will be sufficient to determine compliance.

COMPLIANCE SCHEDULE

ExxonMobil stated that the commission has not provided legal justification for the proposed December 31, 2004 compliance date. ExxonMobil asserted that this date exceeds federal requirements because it believes the commission has the discretion, supported by federal law, EPA policy, and precedent, to specify a 2007 compliance date.

The commission has modified the original proposal to call for the final phase of reductions after the mid-course review and in the 2006-2007 time frame. The commission will review the option of an attainment date extension, if that becomes necessary, when appropriate. The measures adopted here are being implemented as expeditiously as practicable. The commission believes that the measures adopted here will be sufficient to demonstrate attainment with the one-hour ozone standard along the time line indicated by federal guidance.

BCCA asserted that the NO_x SIP point source rule proposal preamble lacks valid, current, and adequate scientific and technical support for the proposed implementation timing, and that there is no discussion or consideration of implementation timing issues.

The implementation schedule and the technical feasibility have been analyzed separately in this adoption preamble in order to show as clearly as possible the reasoning the commission used in adopting the ESADs and in developing the compliance schedule. The commission has tried to use the term technical feasibility in a sense that does not depend on the schedule. What is technically feasible is a function of the state of current engineering practice. The appropriate schedule for applying the technically feasible controls is a function of the practicability (or difficulty) of a certain rate of application. In other words, control measures which are technically feasible remain so, but there needs to be a feasible schedule to apply them. Responses to comments concerning the technical feasibility are discussed in detail earlier in this preamble under the heading of *TECHNICAL FEASIBILITY* for the various source categories. Implementation timing issues are addressed in the remaining portion of this section of the preamble.

Baytown, Baytown COC, BCCA, Chevron, Crown, Diamond-Koch, Dynegy, Entergy, Enterprise, Equistar, ExxonMobil, GPA, Lyondell-Citgo, Lyondell, Kinder Morgan, NASA, PECO, Phillips 66, REI, Rhodia, TCC, Texas Eastern, TGC, TGP, TPIEC, TxOGA, Union Carbide, Valero, and five individuals commented that an adequate amount of time should be given for compliance with the new requirements, while Sierra-Houston supported the proposed three-year compliance schedule for electric utility EGFs. BP stated that its plants could comply with the proposed compliance schedule but suggested that half the emission reductions be required by December 31, 2003, with the remainder by December 31, 2004. BP, BCCA, and Diamond-Koch stated that a longer compliance schedule would allow phase-in of controls with normal planned outages. Chevron suggested that half the emission reductions be required by June 2003, with the remainder by December 31, 2004, with the availability of the executive director to grant a six to 12-month extension if necessary. Baytown and Baytown COC suggested that the compliance date should be May 2007. Dynegy, Entergy, Equistar, Goodyear, Lyondell, PECO, Texas Eastern, TPIEC, and Valero suggested a five-year implementation schedule, beginning December 31, 2002 and ending December 31, 2007. Lyondell-Citgo, Phillips 66, and TxOGA stated that the compliance date should be no earlier than 2007. NASA stated that a longer compliance schedule should be included for federal facilities due to budgetary and timing constraints. Rhodia suggested that the phased compliance schedule be replaced with a compliance date of 2005 for all emission reductions. TCC stated that the annual reduction targets be applied to HGA as a whole, rather than to specific, individual sources, and that the first annual one-third reduction target (December 31, 2002) should be limited to major electric utilities, with petrochemical plants specifically excluded. Kinder Morgan, TGC, and TGP stated that the initial compliance date should be December 31, 2003 rather than December 31, 2002. Union Carbide suggested that the annual reduction targets be one-third plus/minus some percentage. Enterprise suggested that 50%-75% of the emission reductions be required by December 31, 2005, with implementation of a mid-course correction by that time. GPA suggested that 10% of the emission reductions be required each year from 2003 through 2005, a 50% emission reduction in 2006, and the remainder in 2007. ExxonMobil stated that the commission has not provided adequate scientific and technical analyses or justification for the proposed December 31, 2004 compliance date and suggested a March 31, 2007 compliance date. An individual suggested that units fired on liquid fuel or nitrogen-laden fuel should be given an additional three years for compliance. BCCA, ExxonMobil, and TCC suggested that the compliance schedule be more consistent with normal process unit turnaround cycles and the availability of manpower and material resources, and stated that this would dramatically improve the cost effectiveness of proposed rule while minimizing the potential for product disruption, supply shortages, and consumer price increases.

After careful consideration of the commenters' concerns and suggestions in conjunction with the 42 USC, §7502(a)(2), requirement to achieve attainment as expeditiously as practicable, the commission has revised the compliance schedule as follows. For sources other than investor-owned electric utilities, the commission is adopting a staged six-year implementation schedule for compliance with the new HGA ESADs. First, 44% of the total reductions required to comply with the ESADs are required by March 31, 2004. The next 45% of the reductions are required by March 31, 2005. The final reductions are required by March 31, 2007. This revised schedule will provide an additional year and a quarter before the first reductions are required, yet still result in 89% of the emission reductions before the critical 2005 ozone season. This schedule will result in emission reductions as expeditiously as practicable, yet will allow the more difficult to control or more expensive emission reduction projects six years to achieve the emission reductions. The commission believes that this revised compliance schedule will allow the emission reduction projects to be more consistent with normal process unit turnaround cycles, allow additional incorporation of emerging technologies, reduce labor and material availability concerns, and concurrently reduce costs, thereby improving the cost effectiveness while minimizing the potential for product disruption, supply shortages, and consumer price increases. The commission also believes that this revised compliance schedule facilitates a determination at the mid-course review by May 1, 2004 to ensure that the final 11% of the reductions are necessary for attainment of the ozone standard. The adopted compliance schedule for sources other than investor-owned electric utilities allows the maximum feasible time under the federal requirement to attain the ozone standard in HGA by 2007.

For investor-owned electric utilities, the commission is adopting a staged six-year implementation schedule for compliance with the new HGA ESADs. First, 46% of the total reductions required to comply with the ESADs are required by March 31, 2003. The next 46% of the reductions are required by March 31, 2004. The final reductions are required by March 31, 2007. The commission believes that this compliance schedule is appropriate for investor-owned electric utilities since emission reduction projects are already underway to implement the majority of the emission reductions necessary to meet the ESADs for investor-owned electric utilities. The adopted compliance schedule for investor-owned electric utilities allows the maximum feasible time under the federal requirement to attain the ozone standard in HGA by 2007.

TCC expressed concern that the proposed compliance schedule will cause financial, planning, and competitive difficulties for smaller, but still major, sources. As an example, TCC stated that a plant with a large boiler and either no, or only a small number of, smaller sources will be required to control the boiler by December 31, 2002 to meet the first one-third rate-of-progress requirement. TCC stated that the requirement to make such a large capital outlay early on in the program relative to larger sources will be very difficult to fund, implement, and schedule and may result in negative effects on the competitiveness of the source.

A major source with a single unit, or a small number of units, does not necessarily have to install controls to achieve all of the target emission reductions by the first compliance date. The owner or operator of each affected source is free to choose the control technology which best addresses the circumstances of the affected sources, obtain additional allowances from another facility's surplus allowances, or a combination of the two approaches. The owner or operator might choose to make Tier I combustion modifications sufficient to achieve the initial rate-of-progress reductions in order to delay the capital expenditure for Tier II controls until a later date. Alternatively, the owner or operator might choose to implement the emission reduction projects ahead of schedule in order to be able to sell the surplus allowances. There is an infinite number of permutations. Ultimately, each owner or operator will make a business decision believed to represent the best choice for each unique situation. As described earlier in this section of the preamble, the commission lengthened the compliance schedule. This will allow additional incorporation of emerging technologies, reduce labor and material availability concerns, and concurrently reduce costs.

BCCA stated that for all of the HGA point source categories, there is no experience with retrofit NO_x control technology applications that have been demonstrated to perform at the levels proposed, and that time for technology development, testing, and prototyping before commercialization will be required to overcome the many technical limitations that are now being identified as the result of detailed engineering and design reviews. BP, Diamond-Koch, and TCC stated that a longer compliance schedule could allow capture of benefits from emerging technologies as well as ease concerns about availability of labor and materials. BCCA stated that the commission has not allowed for sufficient time for the necessary technology developments with the proposed December 31, 2004 compliance date.

The commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of the adopted ESADs. The commission is aware that there undoubtedly will be cases in which an owner or operator evaluates the circumstances of a particular unit and determines, for whatever reason, to pursue an option other than retrofit control technology. The commission has determined that the various controls which can be used to meet the ESADs have a proven performance experience and agrees with BP that the 90% reductions are technically feasible. A detailed explanation of how the commission has reached these conclusions is provided in the responses to comments earlier in this preamble.

NO_x controls have rapidly improved in capability recently. It is also clear from the numerous technical innovations under development today that NO_x control technology is continuing to improve rapidly. The commission agrees with the commenters that a longer compliance schedule could allow capture of benefits from emerging technologies as well as ease concerns about availability of labor and materials. As described earlier in this section of the preamble, the commission extended the compliance schedule for sources other than investor-owned electric utilities. This will allow additional incorporation of emerging technologies, reduce labor and material availability concerns, and concurrently reduce costs.

BCCA and TCC stated that the December 31, 2004 compliance date does not recognize the magnitude of manpower and material resources required to implement the proposed rule, does not allow for the practical implementation of controls, and is not physically possible. BCCA and TCC stated that the proposed implementation timing is too short and will cause significant manpower, material, and equipment shortages nationwide, will result in supply disruptions of fuels, petrochemical products and intermediates, and will unnecessarily increase the cost of products for consumers. BCCA stated that facility operators will need 12-18 months from the December 2000 rule adoption to scope and design equipment, secure permits, perform detailed engineering, secure funding, and begin the installation of controls. BCCA stated that consequently it will not be until 2002 that many companies will be in a position to begin control installation, leaving only three years for some 180 companies to begin retrofitting over 2,500 individual units. BCCA commented that these companies will be competing for limited resources to engineer, design, permit, construct, and operate some 1,900 boilers, heaters, turbines, and engines, newly modified with SCR technology.

BCCA stated that a study completed by a consultant determined that demand for construction labor between 2002-2004 will consume 175% the available supply in the entire upper Gulf Coast (HGA to Baton Rouge, LA) area as forecasted by the 2000 *Houston Business Roundtable--Gulf Coast Workforce Projection Survey*; that demand for front-end design engineering human resources between 2002-2004 will consume 145% of the available nationwide supply as forecasted by the 1999 *Joint Industry Program Engineering, Procurement and Construction Survey*; and that demand for detailed engineering design resources between

2002-2004 will consume 128% of the available nationwide supply as forecasted by the 1999 *Joint Industry Program Engineering, Procurement and Construction Survey*.

BCCA further stated that the consultant's study determined that highly specialized labor resources, such as furnace engineering evaluation specialists and flue-gas computational fluid dynamics modelers are expected to be in short in supply and a critical path limitation to timely completion of engineering design activities; and that demand for burner testing facilities to demonstrate, certify, and guarantee NO_x emission performance of new burners will exceed current worldwide burner testing capability by 200%. BCCA stated that this will be another critical path limitation to timely delivery of new burners to meet the proposed December 31, 2004 compliance deadline. BCCA also stated that demand for SCR catalyst for HGA and the 22 State OTAG NO_x SIP Call between 2002-2004 will exceed available worldwide production capability by 500%. ExxonMobil expressed similar concerns about the results of the consultant's study.

The commenters have overstated the number of SCRs that will be installed. Point source NO_x reductions in the range of 90% requires the combined use of combustion modification and flue gas controls on the majority of large combustion units. The capabilities of both combustion modifications and flue gas controls are well documented in the NO_x control literature, including the EPA ACTs, papers at numerous meetings of research and trade organizations for industry, NO_x control vendors, constructors, and the government. These documents report combustion-based reductions from minimal to over 90%, and flue gas controls in the range of 75% to 95%. Reduction capabilities as reported in the literature continue to improve and technology has developed rapidly since the late 1980s when a number of California districts set retrofit NO_x control standards. Both combustion modifications and flue gas cleanup are established technologies. Technology is replicable, so in a true sense, the first successful SCR project was sufficient to demonstrate its feasibility. With more than 500 applications of SCR reported by 1997 and growing rapidly, in many different exhaust streams with widely varying degrees of temperature and contaminants, its technical feasibility is not a question. The combination of combustion and flue gas controls can provide overcompliance with the standards in a number of cases and will allow for meaningful choices in the selection of control strategies. Examples of units which have been retrofit to levels below the adopted emission specifications and further details of the technical feasibility of the emission specifications can be found elsewhere in this preamble. Overcontrol on some units will enable others to be under controlled, which will result in substantial cost savings. Although the exact degree of cost savings is not determinable, one vendor has estimated the number of SCRs at 800, rather than the approximately 1,200 that the Chapter 117 cost note contemplated. Although the number of SCRs is expected to be unprecedented, the ultimate number installed is virtually certainly going to be lower as a result of the cap and trade rules, representing significant cost savings. The market-based approach embodied in the adopted rules give nearly complete freedom on how to achieve the goals and based on experience from California, will stimulate the development of new and innovative reduction technologies and strategies. The history of economics shows that the market adjusts to changing market conditions by developing additional supply when there is an increased demand for a product or service. As described earlier in this section of the preamble, the commission lengthened the compliance schedule. This will allow additional incorporation of emerging technologies, reduce labor and material availability concerns, and concurrently reduce costs.

Kinder Morgan, TGC, and TGP stated that the commission did not address issues with respect to FERC and the National Environmental Policy Act (NEPA) (18 CFR Part 380). Kinder Morgan, TGC, and TGP stated that interstate natural gas pipeline systems, including compressor stations, used in the interstate transportation of natural gas are governed by the Natural Gas Act, 15 USC, §§717 et seq. (NGA) and regulated by the FERC, which typically acts as the lead agency in the implementation of the regulations and guidelines of NEPA. Kinder Morgan, TGC, and TGP stated that the NGA requires that interstate pipeline system compression capacity be approved by the FERC. Kinder Morgan, TGC, and TGP stated that the installation of new compression requires an applicant to file with the FERC an Application for a Certificate of Public Convenience and Necessity (Application) under the NGA, §7(c). Kinder Morgan, TGC, and TGP stated that it is unlikely that the electric motor driven compression will exactly match the existing FERC certificated IC compression capacity at any given compressor station and that as a result, it will be required to apply for and obtain FERC approval consisting of a Certificate of Public Convenience and Necessity (Certificate) prior to the construction of any replacement facilities. Kinder Morgan, TGC, and TGP stated that the application preparation, review, and approval process typically takes at least one year. Kinder Morgan, TGC, and TGP stated that additionally, the FERC is required to evaluate cumulative impacts potentially resulting from a proposed project, and that such cumulative impacts include the displacement of emissions from the end user (e.g., Kinder Morgan, TGC, or TGP) to the energy source (the EGF), new electric transmission corridors, areas associated with the disposal of the facilities being replaced, and installation of electric transmission lines to provide electrical power for the newly constructed electric driven compression. Kinder Morgan, TGC, and TGP stated that due to the level of effort involved in the preparation of an application and the FERC review timeline, it is highly unlikely that interstate natural gas pipeline companies would receive the appropriate FERC approvals to authorize construction prior to January 1, 2002. Kinder Morgan, TGC, and TGP stated that as a result, additional time is needed to meet the mandatory requirements for electric conversion.

As noted earlier in this preamble, the commission re-examined the issues of technical feasibility of the proposed ESADs for stationary IC engines and adjusted these ESADs such that the level of control is technically feasible without wholesale replacement of engines. Nevertheless, an option for compliance with the ESADs is still the replacement of IC engines with electric drive motors, as in fact has already occurred at some sites due to the cost savings associated with reduced labor costs for maintenance of the IC engines. As described earlier in this section of the preamble, the commission extended the compliance schedule for sources other than investor-owned electric utilities in order to allow implementation of emission reduction projects as efficiently as possible and reduce the unscheduled downtime and any associated costs. This longer compliance schedule will also allow the necessary time for owners and operators to address FERC and NEPA issues associated with the replacement of IC engines with electric drive motors. In addition, there is no major federal action associated with these rules that triggers compliance with NEPA.

BCCA stated that if electric drive motors replace engines, the sheer number of replacements will strain the availability of motors, switch gear, and other components and that power will have to be supplied to 36 sites at an average of three miles per site. BCCA stated that installing NSCR on rich-burn engines will lead to the same concerns over catalyst availability and competition for welders and general construction workers as for other source categories. BCCA and TGC also stated that LEC technology for lean-burn engines is highly specialized and requires almost case-by-case engineering to optimize the technology as well as specialized expertise to install the hardware. BCCA stated that this specialized engineering and installation expertise is in short supply; the specialized hardware is supplied primarily by after-market vendors since many of the original equipment manufacturers are no longer in business or no longer support some of the engine models used in HGA; and after-market vendors will have difficulty supplying parts for large-scale retrofit activity over a short time frame.

The assessment of a leading vendor of electric drive motors and the related equipment for compressor stations is that there is adequate manufacturing capacity to respond to the increased demand within the proposed time frame. The expected widespread conversion to electric motors for the larger sites and the many rich-burn IC engines which already have NSCRs and air-fuel ratio controllers as a result of NO_x RACT limits the number of NSCR and LEC retrofits. There is a significant infrastructure in place in HGA for supplying emission controls for gas-fired engines which has little overlap with other specialized service providers for other source categories. A leading vendor of NSCR catalyst indicates that manufacturing capacity will not be an issue. NSCR catalyst is used by the automobile manufacturing industry and the stationary source market is very small by proportion. Nonetheless, phasing the controls in with a six-year compliance schedule would have a significant mitigating effect on any supply issues which may arise, particularly for SCR and LECs, which will be competing with the SIP call sources.

BASF, BCCA, Dynegy, Equistar, Lyondell-Citgo, Lyondell, Phillips 66, TCC, TIP, TPIEC, TxOGA, Union Carbide, and Valero commented that the compliance date for installation of totalizing fuel flow meters and CEMS/PEMS should be changed from December 31, 2001. BASF suggested that the deadline be consistent with the SIP compliance dates of December 31, 2002-2004. BCCA, Equistar, Lyondell, Phillips 66, TCC, TIP, TPIEC, TxOGA, and Valero suggested that the deadline be changed to 2007. BASF stated that unit outages may be required for fuel flow meter installation and that CEMS/PEMS certification may be difficult to complete by December 31, 2001 due to the limited number of testing companies and their workloads. BASF, Dynegy, Lyondell-Citgo, Phillips 66, TPIEC, TxOGA, Union Carbide commented that CEMS/PEMS selection depends on the type of controls that are installed and therefore, that monitoring should not be required prior to the installation of the required controls. BASF, Dynegy, TPIEC, and Valero suggested that stack testing be used prior to CEMS/PEMS installation to verify emission estimates.

The rules have been changed in response to this comment. The commission proposed a December 31, 2001 compliance date for installation of emissions monitors and fuel meters in order to improve the consistency of the value of a NO_x allowance at the start of the trading program and to improve the inputs used in the commission's air quality planning tools. However, the proposed schedule did not take into account the practicalities identified by the commenters. Both PEMS and CEMS vendors indicated that the number of monitors required in one year would strain their abilities to provide the equipment. The owners identified clear benefits of installing the monitors in conjunction with the control equipment. If a CEMS is installed before the flue gas controls are fully constructed, the CEMS may need to be uninstalled during construction and possibly relocated after NO_x controls. A PEMS will need to be retrained after the installation of control equipment. Phasing in CEMS/PEMS with the emission control equipment is a more rational and cost-effective approach. Therefore, the commission has modified §117.520(c) to require that the monitors will be phased over a four-year period, at the earlier of installing emission controls or March 31, 2005. This phase-in will achieve the end result benefits of specified emissions reduction by 2005. Because the first reduction period has been extended to 2004, the greater uncertainty about NO_x emissions in the first two years of the program (compared to monitors in place by 2002) will be of less consequence.

The EPA commented on the proposed revision to §117.510(b)(2)(B), which would modify the compliance schedule for utility boilers in DFW by allowing utility boilers retired and decommissioned before May 1, 2005 to be excluded from the calculation of the emission reductions to be made by May 1, 2003. The EPA stated that the commission should include a justification of how this approach will implement reductions as expeditiously as practicable, or the rule would not be approvable for the DFW SIP.

The revised schedule will facilitate an orderly installation of NO_x controls by allowing soon-to-be-retired utility boilers to remain online during the construction and startup of emission reduction projects in DFW. This will ensure the continued reliability of the electric power distribution grid during the transition period, which is necessary in order for the implementation of emission reductions as expeditiously as practicable. The emission reductions from the soon-to-be-retired utility boilers will occur before the critical 2005 ozone season, and therefore will contribute to DFW's attainment of the ozone NAAQS.

COST

BCCA, Entergy, Equistar, ExxonMobil, and Lyondell asserted that most of the emission limitations were developed with a less than complete analysis of the economic feasibility of the resulting controls, or an analysis of the possible economic disbenefit of the proposed controls. BCCA and ExxonMobil stated that the commission appears to have first established an arbitrary NO_x reduction target for point sources (i.e., 90%) and, through an iterative process, back-calculated the emission limits necessary to achieve the desired target. BCCA and ExxonMobil stated that this is "an arbitrary approach to establishing air pollution standards, and circumvents the intent established in the Texas Clean Air Act to establish standards based on a technological and economical review of available control measures."

TCAA, §382.011, requires the commission to establish the level of quality to be maintained in the state's air and to control the quality of the state's air. The commission is required to "seek to accomplish" this through the control of air contaminants by "practical and economically feasible methods." The level of quality of the state's air is measured by whether the air complies with the NAAQS. According to 42 USC, §7409(b), national primary ambient air quality standards are standards which, in the judgment of the administrator of the EPA, are requisite to protect the public health. The criteria for setting the standard is protection of public health, which includes an allowance for an adequate margin of safety. The ESADs were developed in order for HGA to achieve attainment with the ozone NAAQS, which is a health-based standard and not a cost-based standard.

As described in detail earlier in this preamble, the ESADs are not arbitrary and were developed with sufficient analysis to justify the limits and the technical feasibility of the resulting controls. The proposed rules contained a detailed, but admittedly approximate, estimate of the costs of the controls based on information available to the commission. There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the commission must seek to accomplish the goal of protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

Because flexibility in compliance will provide a greater incentive and ability to achieve the goal of attainment, the commission is implementing the mass emissions cap and trade program. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet emission reduction requirements. The mix of control technologies can be greater because the owner can manage activity levels of equipment and place higher levels of control on high utilization units and less controls on less utilized units. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs. This demonstrates that the commission has sought to accomplish its duty.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

TCAA, §382.012, also requires the commission to develop a general comprehensive plan for the proper control of the state's air. The control of the air quality includes various measures such as emission limits and controls on point sources through permit and rules, as well as regulation of certain on-road and non-road sources, and, for compliance with the NAAQS, the control plan meets the FCAA requirement to develop a SIP. As discussed earlier in this preamble, this rule adoption is one element of the control strategy for the HGA SIP and it is the adoption and implementation of this control strategy is necessary in order for the HGA nonattainment area to comply with the requirements of the FCAA and achieve attainment for ozone. Specifically, this rule adoption comprises a large portion of the control strategy necessary to achieve attainment. Therefore, the requirement to properly control the state's air must also meet the comprehensive plan requirements, implemented through the SIP. Unless the plan meets the SIP requirements in the FCAA, which includes meeting NAAQS, the commission is not in compliance with the TCAA. Therefore, the plan as a whole must be examined to ensure that all legal requirements are met. The Texas Code Construction Act, Texas Government Code, §311.021, requires that it is presumed that the entire statute is intended to be effective. Thus, a reading of TCAA, §382.011 and §382.012, leads to the conclusion that the adopted rules meet the requirements of both the TCAA and FCAA.

BCCA stated that three key options for NO_x control are available: application of retrofit control technology on existing equipment; replacement or consolidation of existing equipment; and shutdown of existing equipment. BCCA asserted that there is no evidence in the proposed rule that the commission weighed and analyzed the costs of the potential control options that operators will be required to use to reach NO_x reduction targets. BCCA stated further that there will be instances where the direct application of retrofit technology will not meet the desired NO_x emission targets and where replacement and consolidation of existing equipment will not be economically feasible. BCCA stated that in those instances, the shutdown of equipment must be considered as the last remaining viable measure to meet the NO_x reduction. BCCA stated that capacity reductions, product line shutdowns, and some plant shutdowns will occur as a result of the proposed rule and asserted that the commission has not considered the economic impacts of the anticipated capacity reductions and shutdowns that could occur as a result of the proposed emission limitations.

The comments received did not identify specific plants or equipment lines that would be rendered uneconomical as a result of the cost, and therefore there is no indication that there will be widespread shutdowns. In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates that, even with the use of the mass emissions cap and trade program, that choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment that the rules are economically infeasible. ExxonMobil said that cost analyses would have to be done and some production lines would shut down; if this were to occur on a limited scale it could be viewed as the most rational solution to obtaining the goals of a cleaner environment and maintaining an efficient marketplace. Experience has shown that stringent environmental controls have not wrecked an economy; the NO_x controls in SCAQMD are one example. Indeed, discernible economic effects in Los Angeles have been hard to measure. As the nature of the economy changes, there is a growing belief that environmental measures are necessary for sustained growth. The concurrence of the long economic expansion in the 1990s with significantly increased spending for air emission reductions in local areas such as in Los Angeles under RECLAIM, and nationally under 1990 FCAA mandates addressing smog, hazardous pollutants, and acid deposition, is an indication that strict air emission controls and economic growth can coexist.

Further, for those instances where the direct application of retrofit technology will not meet the desired targets, the commission has built in flexibility to comply with the ESADs, rather than requiring specific methods of controls. Because flexibility in compliance will provide a greater incentive and ability to achieve the goal of attainment, the commission is implementing the mass emissions cap and trade program. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet emission reduction requirements. The mix of control technologies can be greater because the owner can manage activity levels of equipment and place higher levels of control on high utilization units and less controls on less utilized units. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs. This demonstrates that the commission has sought to accomplish its duty.

BCCA stated that the estimated total capital cost for affected HGA sources of approximately $2.7 billion is low by more than a factor of two, and suggested that the commission's cost estimates were based on new, grass roots facilities that have been specifically designed for low-NO_x performance technology, as opposed to cost estimates for the retrofitting of existing equipment. CAP, Clear Lake COC, Crown, Dow, Dynegy, ExxonMobil, Houston MPO, Lyondell-Citgo, Phillips 66, REI, and Texas City Mayor Carlos Garza expressed similar concerns about the cost of control technology.

The costs of SCR for the coal and gas-fired utility boilers were estimated from the cost models contained in Appendix D of *Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers*, issued by NESCAUM (June 1998). In addition, the catalyst cost for the coal-fired boilers was estimated from discussions with engineers familiar with SCR application, and the catalyst cost for gas-fired boilers was estimated based on more specific cost information from gas-fired installation in the Los Angeles area, as identified in the May 5, 2000 issue of the *Texas Register* (25 TexReg 4157). The NESCAUM report was based on actual retrofit data for electric utility boilers and 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 NESCAUM report states that the costs are "anchored in reality" rather than being mere speculation.

Although the total capital cost estimate may have been imprecise, most estimates were for retrofits or replacement projects, rather than new grass roots facilities. The largest cost element was for the set of industrial boilers and process heaters in size above 40 MMBtu/hr at refineries and chemical plants, for which the presumed control approach was applying combustion modifications and SCR. As discussed in the preceding paragraph, the cost model for these sources was based on actual retrofit data, but for electric utility boilers. The model's cost curve, from specific retrofit projects, showed sharply higher costs for the smaller utility boilers. Nonetheless, the retrofit costs may have been underestimated on average because of generally tighter spatial layouts at refineries and chemical plants as compared with small utility boilers. In particular, many of the larger refinery and chemical plant heaters have more obstacles in the form of piping and ducting of process streams than steam boilers. On the other hand, by retrofitting process heaters to the levels of the ESADs in areas such as Los Angeles, experience has been gained which will result in lower costs on subsequent applications. Flue gas cleanup technologies which operate at lower temperatures than conventional SCR, such as low temperature SCR and low temperature oxidation, offer the possibility of minimizing the amount of existing equipment which has to be taken apart.

The gas turbine costs were based on the gas turbine ACT. The EPA's ACTs normally provide retrofit cost data, but the database of retrofits for gas turbine SCRs was small, and the EPA contractor reported the cost of new units rather than retrofits. BCCA may be correct that the cost in the preamble was underestimated for gas turbines. Because capital costs are amortized over the life of the control equipment and combined with operating costs in calculating the cost effectiveness, even if the cost were underestimated by a factor of two, the average cost effectiveness would not double. Further, BCCA's turbine cost estimates are not large enough to result in the overall rule capital cost to be underestimated by a factor of two.

In addition, it should be noted that the NO_x control technologies evaluated in the gas turbine ACT document include steam and water injection, DLN, and SCR. New control technologies are available now that were not available when the ACT was issued in 1993, including low- and high-temperature SCR, catalytic combustion, and catalytic adsorption technology. According to a principal supplier of conventional SCR to the gas turbine market, advances in SCR technology since 1997 have resulted in a 20% reduction in the amount of catalyst needed to achieve a particular reduction target, that experience gained in the design and installation of SCR units has lowered engineering costs, and that these two factors have substantially reduced SCR costs since the 1993 ACT document. Operating costs have been reduced through innovations such as using hot flue gas to pre-heat ammonia injection air, thereby lowering the power requirements of the ammonia injection system.

The engine costs were based on specific costs of electric motor conversion of a gas-fired compressor station in Houston, so they also were not based on grass roots installations costs.

The cost estimates in other categories which were based on SCR control used the same cost model as the heaters and boilers, which as discussed earlier, used actual SCR retrofit data.

The CEMS cost estimates were based on the EPA cost model, *U.S. EPA's Continuous Emission Monitoring System Cost Model, Version 3.0*, a flexible model which details more than 50 individual cost components associated with the purchase and installation of a CEMS. CEMS vendors corroborate costs similar to the EPA model. The commission notes that the number of CEMS/PEMS would be closer to 700 than the 300 in the rule proposal preamble because many of the boilers and heaters in the 40-100 MMBtu/hr range are expected to install SCR, which necessitates a NOx monitor. Using the EPA cost model, the commission estimates the cost of 300 additional CEMS to be approximately $72 million.

BCCA, Entergy, and REI stated that the proposed emission specifications for utility boilers are economically infeasible in wide-scale retrofit applications. BCCA stated that although the proposed rate for utility boilers can be achieved in limited applications, the ESAD is economically unreasonable for many gas-fired boilers.

Since July 1999, the commission has received permit applications for at least 25 new gas turbines, in projects representing more than 6,800 MW of new electric capacity, all to be located in HGA and to operate below the 0.015 lb/MMBtu ESAD for gas turbines, using Tier III controls. These projects are likely to make older, far less efficient boilers economically worthless anyway by 2005. In addition, the commission is not required to set ESADs which are economically reasonable. Rather, as discussed earlier in this preamble, the commission must seek to accomplish the requirement to control the quality of the state's air by practical and economically feasible methods. The commission has met those requirements in adopting these rules.

There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the commission must seek to accomplish the goal of protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

Entergy stated that the commission's cost estimate for gas-fired utility boilers underestimate retrofit costs for the region because the units in the NESCAUM report represented an 85% NO_x reduction (i.e., from 0.20 to 0.030 lb/MMBtu), and asserted that the commission did not take into account the significant incremental expense of controlling by 95% (to 0.010 lb/MMBtu). Entergy stated that as a result, the limits for gas-fired utility boilers are financially inequitable. REI similarly stated that the commission underestimated the costs for utility boilers.

The commission disagrees with the commenter. The actual performance data referenced in the first response in the *TECHNICAL FEASIBILITY--UTILITY BOILERS* section clearly indicates that the selection of 85% reduction in the NESCAUM cost evaluation spreadsheet was not meant to illustrate the technical limits of SCR. The cost differential between 85% and 90% reduction with SCR on a gas-fired boiler is likely to be small; 90% reduction is often the most cost-effective reduction. Entergy doesn't need to make a 95% reduction, because they are operating at 0.15 and 0.16 on their 30-day compliance average under the NO_x RACT rule. In addition, combustion modifications appear to be capable of achieving significantly lower than 0.10 lb/MMBtu on many gas-fired utility boilers today. The flexibility of combining additional combustion and flue gas cleanup controls on these boilers will result in costs similar to those estimated in the cost note. The cost note for REI, at $610 million for a 93% reduction, is similar to the $480 million cost that REI has estimated for their 88% reduction plan. There is no requirement that the commission set limits that are financially equitable among types of equipment.

BCCA and REI stated that typical capacity factors for auxiliary boilers are less than 10%, and therefore the costs for SCR are not economically reasonable given the limited NO_x reduction potential and low service factor.

The commission agrees that SCR is not an appropriate choice for auxiliary boilers because they infrequently operate at high loads. The infrequent operation at high loads means that the cost effectiveness will be extremely poor, regardless of whether SCR is technically infeasible in this application. As noted earlier in the *TECHNICAL FEASIBILITY--AUXILIARY BOILERS* section, the commission has added an alternative emission specification as new §117.106(c)(4) for auxiliary boilers, utility boilers, and stationary gas turbines based on Tier I controls. The limit is the lower of any applicable permit limit or 0.060 lb/MMBtu for these units with an annual capacity factor of 0.0383 or less. This annual capacity factor is based on the equivalent 336 hours (14 days per year) at full load operation. This adopted standard is one which some of the auxiliary boilers are currently meeting with combustion modifications, and which should be technically feasible for the others with combustion modifications. This change would significantly lower the cost of control if the utility chooses to control these units rather than make up the reductions elsewhere under the cap and trade program. As discussed earlier in this preamble, the commission must seek to accomplish the requirement to control the quality of the state's air by practical and economically feasible methods. The commission has met those requirements in adopting these rules. There is no requirement that the commission must determine that the costs be economically reasonable.

BCCA stated that the commission's cost estimate of $2.1 million dollars per unit ($403 million total for HGA) underestimate the gas turbine retrofit costs for the region. REI similarly stated that the commission underestimated the costs for gas turbines. BCCA asserted that the EPA reference guide used does not adequately represent retrofit costs, but instead is more representative of the cost of new, grassroots SCR installations as noted in the reference document itself. Based on the best engineering data available from BCCA member companies, BCCA estimated that the capital cost for approximately 180 gas-fired turbines in HGA to be retrofitted with SCR controls to achieve the desired NO_x reduction target will be in the $0.8-1.2 billion range, depending on the turbine design, power output and use. BCCA, Kinder Morgan, Solar Turbines, and TCC stated that the proposed emission specification imposes an excessively high cost on small gas turbines (less than 10-20 MW).

Total annualized costs for turbines were estimated from cost tables 6-6, 6-9, 6-10, and 6-12 of EPA's ACT document, *Alternative Control Techniques Document NO_x Emissions from Stationary Gas Turbines*, (EPA-453/R-93-007). The turbine cost estimate may well be low, but many of them are among the largest sources of NO_x in the area. In fact, of all point source categories in HGA, the gas turbine category has NO_x emissions second only to utility boilers. The commission must consider that reductions from these largest sources are a necessary component of the plan, and it may undermine the economic feasibility to not include this group merely based on underestimated costs for a few categories. Regarding the cost for small turbines, as noted earlier in this preamble, the commission has revised the ESAD in §117.106(c)(3) and §117.206(c)(10) for existing stationary gas turbines rated at less than 1.0 MW to 0.15 lb NO_x per MMBtu. This will mitigate the costs somewhat for these smaller turbines. In addition, the market-based control program is expected to minimize the costs necessary to achieve the required reductions. Specifically, the mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs.

There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the commission must seek to accomplish the goal of protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

Enterprise stated that a 90% reduction from the estimated 60 small gas turbines (i.e., up to ten MW) represent only 2,254 tpy of NO_x reductions at a disproportionately higher cost than for the estimated 180 large gas turbines (i.e., ten MW or greater). BCCA, PECO, REI, and Solar Turbines stated that the proposed emission specifications for gas turbines are economically infeasible in wide-scale retrofit applications. BCCA noted that gas turbines can be found in utility plants, industrial plants, and remote pipeline transmission sites, and stated that each location, and in many cases each machine, has its own unique design and operating conditions that need to be considered when determining the cost of a particular NO_x reduction technology.

The commission agrees that in many cases each gas turbine has its own unique design and operating conditions that need to be considered in evaluating feasibility and cost. As discussed elsewhere in this preamble, gas turbine retrofit costs are likely to be higher than estimated in the rule proposal. The costs for the smallest gas turbines (less than 1.0 MW) have been reduced because the adopted ESAD is based on Tier II controls rather than Tier III controls, and the total reduction required for this category of smallest gas turbines is 0.2 tpd less than proposed.

In addition, the market-based control program is expected to minimize the costs necessary to achieve the required reductions. Specifically, the mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs. Therefore, the commission disagrees that the ESAD for gas turbines are economically infeasible.

There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the commission must seek to accomplish the goal of protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

TECO stated that it would cost $47,500 per ton to add SCR to its four gas-fired boilers which are rated at over 100 MMBtu/hr heat input.

TECO incorrectly calculated the cost per ton by failing to take into account the fact that the emission reductions will continue to occur for the life of the equipment (assumed to be 15 years) rather than for only a single year. Consequently, TECO's estimated cost per ton is significantly overstated. The 0.010 lb/MMBtu emission specification may be achievable with Tier I controls for the single burner boilers above 100 MMBtu/hr that TECO operates. There are at least three burner vendors with experience in achieving ESAD levels of NO_x in single burner gas-fired boilers, with at least two dozen retrofits. It appears unlikely that TECO will need to install SCRs because of the burner technologies offered by these vendors. Ultralow-NO_x burner technology is less expensive than retrofit of the SCR controls assumed by TECO in its cost estimate; therefore the overall cost of achieving the necessary emission reductions from TECO's boilers will be much lower.

BCCA stated that there is no analysis in the rule proposal preamble to describe the economic feasibility of the proposed retrofit limits for FCCUs, incinerators, dryers, pulping recovery furnaces, steel furnaces, kilns, or other sources. BCCA and TxOGA requested that the commission provide the economic feasibility analysis for the proposed ESADs for FCCUs. BCCA requested that the commission provide the economic feasibility analysis for the proposed ESADs for incinerators.

The cost estimates were published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8287-8293). The market-based control program is expected to minimize the costs necessary to achieve the required reductions. Specifically, the mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs.

Regarding stationary IC engines, BCCA, EMA, ExxonMobil, GPA, Kinder Morgan, Pasadena/Donohue, TCC, Texas Eastern, TGC, and TGP stated that the rule proposal preamble cites costs for just one site and stated that this site may not be operating the replacement electric drive motors as base-load equipment. The commenters stated that other recent gas industry experience with electric drive replacement indicates the cost may be higher than cited in the rule proposal preamble. BCCA, GPA, and TGP stated that the economic feasibility cited in the preamble also relies, in part, upon the value of credits generated by shutdown of the replaced engines and stated that at a limit of 0.17 g/hp-hr, replacing engines with electric drive will generate very few credits. ExxonMobil expressed similar concerns regarding replacement of stationary IC engines with electric drive motors. EMA stated that a stationary gaseous-fueled engine rated at greater than 3,000 hp could meet the proposed limit with advanced SCR, but this control would be costly. GPA, Kinder Morgan, Texas Eastern, TGC, and TGP stated that the emission specifications are unattainable without significant capital expenditure. MECA stated that NSCR can achieve NO_x emission reductions of more than 90% from rich-burn engines or engines operated stoichiometrically at a cost of $10-$15 per bhp, that SCR can achieve NO_x emission reductions of more than 90% from lean-burn engines at a cost of $50-$125 per bhp, and that lean NO_x catalysts can achieve NO_x emission reductions of more than 80% from lean-burn engines at a cost of $10-$20 per bhp.

As described earlier in this preamble, the commission has revised the ESADs for IC engines in order to ensure that the ESADs are technically feasible without wholesale replacement of equipment, thereby significantly reducing the costs. The cost of electrification of stationary IC engines and the cost of upgraded electric transmission lines to sites was based on certified costs of a project completed in 2000 in HGA and was corroborated by an individual knowledgeable with such projects as being very representative of costs of this kind of project. An option for compliance with the ESADs is still the replacement of IC engines with electric drive motors, as in fact has already occurred at some sites due to such factors as the cost savings associated with increased automation and reduced labor costs for engine maintenance. The commission expects continuation of the trend toward replacement of additional IC engines with electric drive.

Wyman-Gordon stated that its furnace mechanical contractor estimated the cost for its five reheat furnaces and four heat treat furnaces to meet the proposed emission rates to be approximately $4.2 million to install low-NO_x burners and approximately $700,000 to adjust the burners to be compatible with the furnaces, for a total of approximately $4.9 million, and noted that this is substantially more than the commission's estimate. Wyman-Gordon commented that the EPA's ACT document, *Alternative Control Techniques Document--NO_x Emissions From Iron and Steel Mills*, states on page 5-8 that heat treat furnaces "operate at a very specific flame point and furnace geometries to achieve a specific 'set point' past which steel processing is most efficient; major problems may occur for a specific furnace without a large amount of equipment reconstruction." Wyman-Gordon stated that the higher cost to achieve the proposed emission rates is because its furnaces have custom designed and built proprietary burners which already have very low NO_x emission rates as compared to standard burners commonly used in reheat and heat treat furnaces. Wyman-Gordon stated that because the burners are custom built, it is not possible to retrofit the burners with an "off the shelf" low-NO_x package and that instead, each burner would need to be completely rebuilt or replaced to achieve the proposed emission rates. Wyman-Gordon also stated that the new burners would have different flame characteristics than the existing burners, requiring modeling and an engineering study to determine the correct placement to achieve uniform heating in the furnaces, and that the cost estimate does not include the cost of lost production time while each furnace is out of operation.

While the commission strives to make the best cost estimate possible based on the available information, it agrees that individually-prepared vendor cost estimates are likely to be more accurate than generic cost information. Regarding the commenter's cost estimates for installation of low-NO_x burners, the commission notes that Tier I control options other than low-NO_x burners are available to reduce emissions from heat treat furnaces and reheat furnaces. For example, an external gas conditioning system can be added which introduces inert gas using existing fuel pressure (i.e., without moving parts) into an eductor where it dilutes the fuel to produce a low-NO_x fuel. The inert gas reduces peak flame temperatures, lowers available O_2 concentration, and minimizes reaction times, thereby reducing both prompt NO_x and thermal NO_x formation. Under demonstration on a utility boiler in Texas, this is currently achieving 0.04 lb/MMBtu, with expectations of even better performance. Other control options are also available. The owner or operator of each affected source is free to choose the control technology which best addresses the circumstances of the affected sources, obtain additional allowances from another facility's surplus allowances, or a combination of the two approaches.

There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the commission must seek to accomplish the goal of protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

BCCA stated that *U.S. EPA's Continuous Emission Monitoring System Cost Model, Version 3.0* understates the cost of NO_x CEMS. BCCA stated that industry experience with installed retrofit costs under the current Chapter 117 rules was in the $350,000-$400,000 range. BCCA also stated that the commission underestimated the number of CEMS required since all units equipped with SCR will require installation of a NO_x CEMS. BCCA asserted that the number of new CEMS will be closer to 700, rather than 300, and, based on industry experience of $350,000 per installation and 700 new CEMS required, estimated the cost of new emission monitoring systems to be $245 million.

The EPA cost model is a flexible model which details more than 50 individual cost components associated with the purchase and installation of a CEMS. The commenters did not provide specifics to support their cost estimates, which are more than double the standard EPA model costs for a NO_x CEMS, so it is hard to evaluate these comments. CEMS vendors corroborate costs similar to the EPA model. The commission agrees that the number of CEMS/PEMS would be closer to 700, because many of the boilers and heaters in the 40-100 MMBtu/hr range are expected to install SCR, which necessitates a NO_x monitor. Using the EPA cost model, the commission estimates the cost of 300 additional CEMS to be approximately $72 million.

In addition, based on vendor quotes, it appears that the cost of CEMS has been dropping, such that the EPA cost model overestimates both the initial and annual costs. Further, the adopted rules allow multiple stacks to share one CEMS, as well as allowing PEMS as an alternative to CEMS, which should further reduce the costs of complying with the adopted rules. It is generally recognized that a PEMS, which consists of equipment necessary for the continuous determination and recordkeeping of process gas concentrations and emission rates using process or control device operating parameters measurements and a conversion equation or computer program to produce results in units of the applicable emission limitation, are generally less expensive than a CEMS. Therefore, the costs estimated by the EPA's cost model could be expected to represent an upper bound of the monitoring costs.

BCCA asserted that there is no discussion or consideration of design and implementation timing issues, which will impact the economic feasibility of the required technology applications.

A phased compliance schedule was included in the adopted rules precisely to take into consideration the design and implementation timing issues. In addition, as noted earlier in this preamble, the commission extended the compliance schedule for sources other than investor-owned electric utilities to address design and implementation timing issues, thereby reducing costs. Also as noted earlier in this preamble, under the mass emissions cap and trade program, the agency will allocate to a source a number of allowances (NO_x emissions in tons) which a source would be allowed to emit during the calendar year. The source is not allowed to exceed this number of allowances granted unless they obtain additional allowances from another facility's surplus allowances. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet emission reduction requirements. The mix of control technologies can be greater because the owner can manage activity levels of equipment and place higher levels of control on high utilization units and less controls on less utilized units. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs.

BCCA and ExxonMobil asserted that the commission has not considered the cost and economic consequences associated with the proposed December 31, 2004 compliance date. BCCA stated that the time between turnarounds ranges from four to seven years, depending on service, or about five years on average. ExxonMobil requested inclusion in the final rule adoption of the costs of the following: over 800 unscheduled plant shutdowns due to the December 31, 2004 compliance date; reduced future growth and capital investments in the energy industries associated with the inability to secure NO_x emission offsets for plant expansions due to the 90% NO_x reduction requirement; reduced industrial property tax revenues resulting from lower future capital investment; and lost jobs and lower wages in the energy industries resulting from lower capital investments in plants and plant shutdowns.

The commission extended the compliance schedule for sources other than investor-owned electric utilities as described earlier in order to allow implementation of emission reduction projects as efficiently as possible and reduce the unscheduled downtime and any associated costs. This will minimize the need for additional outages for installation of controls by allowing more of them to be accomplished during normal plant turnarounds, while concurrently reducing costs associated with lost production.

The adopted compliance schedule allows more than six years for achieving the required NO_x emission reductions. Based on BCCA's estimate that units undergo scheduled outages for maintenance every five years on average, it could be expected that 85% of the units would undergo a scheduled shutdown by March 31, 2005. Owners and operators of units subject to the ESADs have been aware of the need to reduce NO_x emissions by 90% at least since May 1998 and of the specific ESADs at least since August 2000. Therefore, scheduled shutdowns in 2001 could be expected to include implementation of NO_x emission control projects. In addition, some structural work can be accomplished while a unit is operating to reduce the actual down time. Further, scheduled outages can be avoided by accelerating scheduled activities to coincide with unplanned outages. The combination of these strategies could be expected to reduce the number of additional shutdowns to install control equipment.

While the requirement to achieve 89% of the reductions by December 31, 2004 is greater than the 85% of the scheduled outages estimated to occur by this same date, it is also reasonable to expect that projects which generate the largest emission reductions and are most cost-effective will be implemented before projects which result in smaller emission reductions at a higher cost per ton than average. There is also an incentive for early implementation of projects which generate the largest emission reductions and are most cost-effective in order to create excess emission reduction credits which can be sold. The use of these newly-generated credits, in conjunction with existing emission reduction credits, can reasonably be expected to facilitate achieving 89% of the reductions by March 31, 2005 even though 85% of the scheduled outages are estimated to occur by this same date.

There are other areas in the state to locate new facilities which would not require that the new emissions be offset. A shift from HGA to other areas may be one of the ways to deal with air quality problems in HGA.

BCCA stated that there are steps other than application of retrofit technology that must be taken to achieve the 90% reduction target, such as wholesale replacement of sources, consolidation of sources to reduce fuel firing, and shutdown of marginally economic equipment and plants. BCCA stated that it does not believe such steps are economically based emission control standards. BCCA, Equistar, Goodyear, PECO, and TPIEC stated that they do not believe that the commission considered the cost and regional economic impacts associated with such steps.

As described in detail earlier in this preamble, the commission believes the ESADs are technically feasible, albeit with engineering challenges. In a case where an owner or operator evaluates the circumstances of a particular unit and determines, for whatever reason, that equipment replacement and/or consolidation is the best option, that is a business decision which indicates that the owner or operator considers equipment replacement and/or consolidation to be the most cost-effective method of obtaining the necessary emission reductions.

As noted earlier in this preamble, there is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

BCCA, Equistar, Lyondell, and TCC stated that post-combustion retrofit controls have limitations which will cause a decrease in operational reliability and loss of production capacity in many applications. BCCA asserted that the commission has not considered or quantified the economic consequences, such as loss of fuel and petrochemical production capacity, as a result of these technological limitations.

NESCAUM's *Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers* (June 1998) 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 operating experience discussion is, according to the NESCAUM report, "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. 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 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 United States facilities and any impact to facility reliability." In short, there is no reason to expect a decrease in operational reliability with Tier II controls, based upon well-documented experience. Regarding potential loss of capacity, the commission believes that the combined capabilities of Tier I and Tier II technologies will operate in tandem to minimize costs and any potential loss of capacity.

As noted earlier in this preamble, there is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control.

BCCA stated that a 90% NO_x reduction target effectively eliminates the ability to create surplus point source emission reduction credits under the proposed Chapter 101 mass emissions cap and trade program to permit future business expansion in the region. BCCA stated that the proposed level of control provides little or no opportunity for future growth of stationary sources in HGA and that such a "no future growth" plan will eventually put businesses in HGA at an economic and competitive disadvantage in the global marketplace and make them non-competitive for further investment and expansion. BCCA asserted that the commission has not considered the regional economic consequences of what it called a "no future growth" plan. ExxonMobil and Texas Eastern expressed similar concerns about growth and regional economic consequences.

The commission disagrees with the comment. As provided in the earlier specific examples of units achieving the ESADs, many of these units are operating below the ESADs. This demonstrates that it is possible to use overcompliance to create surplus point source emission reduction credits under the adopted Chapter 101 mass emissions cap and trade program. As noted earlier in this preamble, under the mass emissions cap and trade program, the agency will allocate to a source a number of allowances (NO_x emissions in tons) which a source would be allowed to emit during the calendar year. The source is not allowed to exceed this number of allowances granted unless they obtain additional allowances from another facility's surplus allowances. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet emission reduction requirements.

The mass emissions cap and trade program will cap the level of NO_x emitted from stationary sources in the HGA area, thus stopping the possible growth of emissions. Any new source will be required to find and retire allowances equal to the amount of their actual NO_x emissions from sources already participating in the cap. Thus, this program does not limit growth, but it does limit growth of emissions.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs and will not prevent future growth. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs, which the commission expects will result in sufficient available allowances for growth.

BCCA stated that a compliance date of December 31, 2004 will effectively decrease the ethylene industry capacity by 2.8% and cost the HGA ethylene plant operators $330 million dollars in lost sales during the implementation period of 2003-2004 when construction would take place. BCCA asserted that this is one example of the economic costs not considered by the commission in understanding the economic impact of the point source rule. BCCA also stated that this product loss will add $1.65 million, on average, to the cost of each ethylene plant furnace SCR retrofit, more than doubling the average cost the commission estimated for a furnace SCR retrofit.

BCCA did not provide analysis of the basis for its estimated loss of ethylene capacity and lost sales, and added cost to each ethylene plant furnace SCR retrofit. As noted earlier in this preamble, the commission revised the compliance schedule in order to allow implementation of emission reduction projects as efficiently as possible and reduce the unscheduled downtime and any associated costs. This will minimize the need for additional outages for installation of controls by allowing more of them to be accomplished during normal plant turnarounds, while concurrently reducing costs associated with lost production.

The adopted compliance schedule allows at least six years for achieving the required NO_x emission reductions. Based on BCCA's estimate of units undergoing scheduled outages for maintenance every five years on average, it could be expected that 85% of the units would undergo a scheduled shutdown by March 31, 2005. In addition, owners and operators of units subject to the ESADs have been aware of the need to reduce NO_x emissions by 90% at least since May 1998, and the specific ESADs at least since August 2000. Therefore, scheduled shutdowns in 2001 could be expected to include implementation of NO_x emission control projects. In addition, some structural work can be accomplished while a unit is operating to reduce the actual down time. Further, scheduled outages can be avoided by accelerating scheduled activities to coincide with unplanned outages. The combination of these strategies could be expected to reduce the number of additional shutdowns to install control equipment.

While the requirement to achieve 89% of the reductions by March 31, 2005 is greater than the 85% of the scheduled outages estimated to occur by this same date, it is also reasonable to expect that projects which generate the largest emission reductions and are most cost-effective will be implemented before projects which result in smaller emission reductions at a higher cost per ton than average. There is also an incentive for early implementation of projects which generate the largest emission reductions and are most cost-effective in order to create excess emission reduction credits which can be sold. The use of these newly-generated credits, in conjunction with existing emission reduction credits, can reasonably be expected to facilitate achieving 89% of the reductions by March 31, 2005 even though 85% of the scheduled outages are estimated to occur by this same date.

There are other areas in the state to locate new facilities which would not require that the new emissions be offset. A shift from HGA to other areas may be one of the ways to deal with air quality problems in HGA.

BCCA stated that the engineering challenges associated with the retrofit of existing combustion devices with flue-gas treatment technologies add significantly to the cost of a NO_x control project, and urged the commission to make every attempt to quantify these additional costs and include them in the economic analysis associated with the proposed rules.

The comment implies that the engineering challenges associated with the retrofit of existing combustion devices with flue-gas treatment technologies add to the cost of all Tier II NO_x control projects. In fact, only some of the combustion sources which will be retrofitted with Tier II controls will have more difficult engineering challenges associated with the installation, while other installations will be relatively straightforward. For example, gas turbines constructed after 1990 typically have included extra space in the exhaust duct for the subsequent installation of Tier II controls, making the design and installation of Tier II controls much easier and, therefore, less expensive. For most older gas turbines, the heat recovery sections can be moved or low-temperature SCR added at the back end.

As noted earlier in this preamble, there is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control.

BCCA stated that the NO_x reduction potential and cost effectiveness of combustion control technologies are dependent on a number of factors including: starting NO_x emission level; safe operations conditions such as flame stability; process temperature requirements such a radiant heat release and total heat input; physical burner and combustion device geometry and burner size; fuel type quality and variability (e.g., Btu content, level of hydrogen and olefins); and construction issues such as material and equipment availability (e.g., burners, burner testing, combustion modelers, etc.).

The commission basically agrees with these comments. There is no question that there are a number of challenges in achieving the design emission specifications and that there are a variety of factors which affect the NO_x reduction potential and cost effectiveness of combustion control technologies.

As noted earlier in this preamble, under the mass emissions cap and trade program, the agency will allocate to a source a number of allowances (NO_x emissions in tons) which a source would be allowed to emit during the calendar year. The source is not allowed to exceed this number of allowances granted unless they obtain additional allowances from another facility's surplus allowances. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet emission reduction requirements.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs and will not prevent future growth. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs, which the commission expects will result in sufficient available allowances for growth.

BCCA stated that the NO_x reduction potential and cost effectiveness of SCR technology applications is dependent on a number of factors, including: the starting NO_x emission level; safe operations conditions (e.g., ammonia storage and handling); stack gas temperature, sulfur level, and dust loading, all of which affects technology selection and performance; fuel type quality and variability (e.g., presence of catalyst poisons and plugging agents); and construction issues such as combustion equipment type, physical equipment geometry, equipment availability and size, and physical plant plot space limitations. BCCA and TCC also stated that in many retrofit applications, SCR cannot simply be placed at the end of the flue-gas handling system, but must be designed and constructed to operate at the optimum point within the heat recovery system, with such equipment reconstruction adding significantly to the construction cost and to the production downtime necessary to install the project.

The commission basically agrees with these comments. There is no question that there are a number of challenges in achieving the design emission specifications and that there are a variety of factors which affect the NO_x reduction potential and cost effectiveness of SCR and other retrofit post-combustion control technologies. As noted earlier in this preamble, control options other than SCR (for example, ultralow-NO_x burner technology) are available to reduce emissions. The commission notes that ultralow-NO_x burner technology is less expensive than the SCR controls that BCCA has assumed will be necessary. Other control options are also available. Since technologies other than SCR can achieve significant emission reductions, fewer installations of SCR would be expected than either the commission or BCCA assumed in their respective cost analyses, thereby reducing the overall cost of achieving the necessary emission reductions in HGA.

As noted earlier in this preamble, under the mass emissions cap and trade program, the agency will allocate to a source a number of allowances (NO_x emissions in tons) which a source would be allowed to emit during the calendar year. The source is not allowed to exceed this number of allowances granted unless they obtain additional allowances from another facility's surplus allowances. Allowance trading should provide flexibility and potential cost savings in planning and determining the most economical mix of the application of emission control technology with the purchase of other facility's surplus allowances to meet emission reduction requirements.

The mass emissions cap and trade program will also allow sources flexibility in planning the order of emission reduction projects which will best address design and implementation timing issues and result in the most cost-effective approach to achieving emission reductions. For simplicity in the rule proposal preamble, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of OTAG has analyzed market-based emission trading options, such as the mass emissions cap and trade program, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. Consequently, the commission believes that, in practice, the mass emissions cap and trade program will reduce the costs of compliance with the ESADs and will not prevent future growth. In addition, the mass emissions cap and trade program is expected to encourage innovations and development of emerging technology because reductions achieved by controlling emissions to below the ESADs can be sold. In short, there is an incentive to do better than the level specified by the ESADs, which the commission expects will result in sufficient available allowances for growth.

BCCA stated that there will be many instances where the direct application of retrofit technology will not meet the desired NO_x emission targets or the cost to design the system around the engineering challenges will be prohibitive. BCCA stated that equipment replacement and consolidation would, in most cases, be more costly than if the NO_x retrofit applications were technologically and/or economically feasible. BCCA asserted that the commission has not included the cost of equipment replacement and consolidation that will be necessary as a result of the proposed emission limitations.

As described in detail earlier in this preamble, the commission believes the ESADs are technically feasible, albeit with engineering challenges. In a case where an owner or operator evaluates the circumstances of a particular unit and determines, for whatever reason, that equipment replacement and/or consolidation is the best option, that is a business decision which indicates that the owner or operator considers equipment replacement and/or consolidation to be the most cost-effective method of obtaining the necessary emission reductions.

The units with unique retrofit problems and therefore much higher retrofit costs may be fewer than this comment indicates. The capabilities of control technology continue to grow, adding more compliance options. Older equipment often faces higher costs to retrofit because of factors such as operating controls. In those cases for which replacement is the most cost effective option, there are economic benefits that will be enjoyed that offset the higher cost.

There is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control. Rather, the commission must seek to accomplish the goal of protecting air quality through economically feasible methods. The economical feasibility requirement must be read in conjunction with the requirement that the commission control the air through all practical methods. The limits are admittedly stringent, and thus may be more costly to implement than less stringent standards. As discussed earlier in this preamble, similar stringent limits have been met in California for some categories of equipment and therefore are not cost prohibitive. In other categories, there are examples of similar and even lower levels of control on individual units which continue to operate. The commission is merely required to seek economically feasible methods to achieve these stringent limits. By identifying existing examples of most, if not all, of equipment that meets the proposed emission standards, the commission has satisfied the statutory requirement to consider the economic feasibility of the controls. In addition, the commission is not prohibited from requiring the use of economically infeasible methods to achieve the required standard of air quality. Although, as discussed later, the commission has built in flexibility to comply with the ESADs rather than requiring specific methods of controls, the commission recognizes that there will be certain situations in which a particular choice for compliance may be economically infeasible. However, on average for the many types of facilities which must comply with the ESADs, the rules are not economically infeasible. Therefore, commission has met the requirement to seek to accomplish the plan to meet the ozone NAAQS through practical and economically feasible methods.

In addition, no commenter has provided detailed revenue and cost information for either individual units or for the entire HGA area that demonstrates, even with the use of the mass emissions cap and trade program, which provides choices to comply through the use of retrofits, replacement and consolidation, or shut down of existing equipment, that the rules are economically infeasible.

TGP stated that the commission's cost estimate for the electrification of stationary IC engines of $714/hp (not including the cost of upgraded electric transmission lines to the site, which cost approximately $700,000 per mile) overestimates the cost-effectiveness associated with electrification. TGP stated that it has undertaken such electrification projects in Louisiana, Mississippi, Tennessee, and Kentucky, and that based on its experience, the capital cost is approximately $1,099/hp to $1,211/hp. TGP stated that another author *(Economic Considerations for the Use of Electric Motors for Compression on Natural Gas Pipelines*, John P. Fagg, Second Annual Symposium, Electric Power Research Institute) has placed the capital cost for converting a natural gas driven unit to electric drive at $800/hp to $1,500/hp. GPA stated that it estimates the cost of compliance for a 4,000 hp facility to reduce NO_x emissions from 2.0 g/hp-hr to 0.17 g/hp-hr to be $70,000 per ton of NO_x controlled, which it stated is "exorbitant" and an indication that IC engines are disproportionately burdened with high control costs.

GPA incorrectly calculated the cost per ton by failing to take into account the fact that the emission reductions will continue to occur for the life of the equipment (assumed to be 15 years) rather than for only a single year. Consequently, GPA's estimated cost per ton is significantly overstated. However, as described earlier in this preamble, the commission has revised the ESADs for IC engines in order to ensure that the ESADs are technically feasible without wholesale replacement of equipment, thereby significantly reducing the costs. The cost of electrification of stationary IC engines and the cost of upgraded electric transmission lines to sites was based on certified costs of a project completed in 2000 in HGA and was corroborated by an individual knowledgeable with such projects as being very representative of costs of this kind of project. An option for compliance with the ESADs is still the replacement of IC engines with electric drive motors, as in fact has already occurred at some sites due to such factors as the cost savings associated with increased automation and reduced labor costs for engine maintenance. The commission expects continuation of the trend toward replacement of additional IC engines with electric drive.

BCCA stated that the installation of combustion controls, such as low-NO_x burners will, in many cases, reduce the existing capacity of certain combustion devices by about 10%-15% relative to conventional burners, and that this furnace capacity must be reestablished by addition of significant new equipment or production capacity is lost. BCCA stated that the heat input replacement cost or production loss associated with this control technology will significantly increase the overall cost of the NO_x reductions and should be included in the overall regional cost impact assessment. BCCA and Dynegy stated that a reduction in system efficiency associated with post-combustion controls increases the overall long-term cost of the NO_x controls.

BCCA did not explain how the reported 10%-15% reduction in capacity was estimated. The commission believes that the combined capabilities of Tier I and Tier II technologies will operate in tandem to minimize costs and any potential loss of capacity. As noted earlier in this preamble, there is no requirement that the commission determine the probable economic cost of the unique aspects of every facility or source that must comply, nor give the probable economic cost of every possible method of control.

The commenters did not provide details on system efficiency difference. However, the NESCAUM 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.

BCCA stated that the time required to perform SCR retrofits may extend the normal process downtime and result in additional production losses and that such production losses are not typically experienced with combustion hardware changes, which can generally be done during normal major turnarounds. BCCA asserted that the commission has not adequately addressed these issues in the analysis of technical feasibility and cost.

The implementation schedule and the technical feasibility have been analyzed separately in this adoption preamble in order to show as clearly as possible the reasoning the commission used in adopting the ESADs and in developing the compliance schedule. The commission has tried to use the term "technical feasibility" in a sense that does not depend on the schedule. What is technically feasible is a function of the state of current engineering practice. The appropriate schedule for applying the technically feasible controls is a function of the practicability (or difficulty) of a certain rate of application. In other words, control measures which are technically feasible remain so, but there needs to be a feasible schedule to apply them. Responses to comments concerning the technical feasibility are discussed in detail earlier in this preamble under the heading of *TECHNICAL FEASIBILITY* for the various emission source categories.

The commission agrees that the time required to perform SCR retrofits may extend the normal process downtime. For this and other reasons, the commission revised the compliance schedule as described earlier in order to allow implementation of emission reduction projects as efficiently as possible and reduce the additional scheduled downtime and any associated costs. This will minimize the need for additional outages for installation of controls by allowing more of them to be accomplished during normal plant turnarounds, while concurrently reducing costs associated with lost production.

In addition, some structural work can be accomplished while a unit is operating to reduce the actual down time. Further, scheduled outages can be avoided by accelerating scheduled activities to coincide with unplanned outages. These strategies could be expected to reduce the number of additional shutdowns to install control equipment.

SUBCHAPTER A. DEFINITIONS

30 TAC §117.10

STATUTORY AUTHORITY

The amendment is 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; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air, such as the SIP; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

§117.10. 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. An auxiliary steam boiler produces steam as a replacement for steam produced by another piece of equipment which is not operating due to planned or unplanned maintenance.

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

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

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

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

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

(A) All boilers, 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, 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.

(13) 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.

(14) 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.

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

(16) 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.

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

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

(A) an enclosed control device that combusts or oxidizes gases or vapors; and

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

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

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

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

(22) 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.

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

(A) greater than or equal to 40 million 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.

(24) 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.

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

(26) 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.

(27) 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.

(28) 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.

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

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

(31) 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.

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

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

(34) 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.

(35) 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.

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

(37) 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 as defined in this section.

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

(39) 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.

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

(41) 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.

(42) 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.

(43) 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.

(44) 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.

(45) 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.

(46) 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.

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

(A) for the purposes of §117.105 and §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology) and each requirement of this chapter associated with §117.105 and §117.205 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section; or

(B) for the purposes of §117.106 and §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations) and each requirement of this chapter associated with §117.106 and §117.206 of this title, any boiler, process heater, stationary gas turbine, or stationary internal combustion engine, as defined in this section, or any other stationary source of nitrogen oxides (NO_x) at a major source, as defined in this section.

(48) Utility boiler--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.

(49) 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.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009083
Margaret Hoffman
Director, Envronmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

SUBCHAPTER B. COMBUSTION AT MAJOR SOURCES
DIVISION 1. UTILITY ELECTRIC GENERATION IN OZONE NONATTAINMENT AREAS

30 TAC §§117.101, 117.103, 117.105, 117.106, 117.108, 117.111, 117.113, 117.114, 117.116, 117.119, 117.121

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; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air, such as the SIP; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

§117.103. Exemptions.

(a) Reasonably available control technology. Units exempted from the provisions of §§117.105, 117.107, and 117.113 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Alternative System-wide Emission Specifications; and Continuous Demonstration of Compliance), except as may be specified in §117.113(h), (i), and (j) of this title, include the following:

(1) any new units placed into service after November 15, 1992;

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

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

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

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

(b) Emission specifications for attainment demonstrations. Stationary gas turbines and engines which are used solely to power other engines or gas turbines during start-ups are exempt from the provisions of §§117.106, 117.108, and 117.113 of this title (relating to Emission Specifications for Attainment Demonstrations; System Cap; and Continuous Demonstration of Compliance), except as may be specified in §117.113(i) of this title.

(c) Emergency fuel oil firing.

(1) The fuel oil firing emission limitations of §§117.105(c), 117.106(a), (b), and (c)(1)(B), 117.107(b), and 117.108 of this title shall not apply during an emergency operating condition declared by the Electric Reliability Council of Texas or the Southwest Power Pool, or any other emergency operating condition which necessitates oil firing. All findings that emergency operating conditions exist are subject to the approval of the executive director.

(2) The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction verbal notification as soon as possible but no later than 48 hours after declaration of the emergency. Verbal notification shall identify the anticipated date and time oil firing will begin, duration of the emergency period, affected oil-fired equipment, and quantity of oil to be fired in each unit, and shall be followed by written notification containing this information no later than five days after declaration of the emergency.

(3) The owner or operator of an affected unit shall give the executive director and any local air pollution control agency having jurisdiction final written notification as soon as possible but no later than two weeks after the termination of emergency fuel oil firing. Final written notification shall identify the actual dates and times that oil firing began and ended, duration of the emergency period, affected oil-fired equipment, and quantity of oil fired in each unit.

(d) Distributed generation. Upon issuance of a standard permit by the commission for small (ten megawatts or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid, combustion sources registered under that permit are exempt from this chapter.

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

(a) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, emissions of nitrogen oxides (NO_x) in excess of 0.26 pound per million (MM) Btu heat input on a rolling 24-hour average and 0.20 pound per MMBtu heat input on a 30-day rolling average while firing natural gas or a combination of natural gas and waste oil.

(b) No person shall allow the discharge into the atmosphere from any utility boiler, NO_x emissions in excess of 0.38 pound per MMBtu heat input for tangentially-fired units on a rolling 24-hour averaging period or 0.43 pound per MMBtu heat input for wall-fired units on a rolling 24-hour averaging period while firing coal.

(c) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of 0.30 pound per MMBtu heat input on a rolling 24- hour averaging period while firing fuel oil only.

(d) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler, NO_x emissions in excess of the heat input weighted average of the applicable emission limits specified in subsections (a) - (c) of this section on a rolling 24-hour averaging period while firing a mixture of natural gas and fuel oil, as follows:
Figure: 30 TAC §117.105(d) (No change.)

(e) Each auxiliary steam boiler which is an affected facility as defined by New Source Performance Standards (NSPS) 40 Code of Federal Regulations (CFR), Part 60, Subparts D, Db, or Dc shall be limited to the applicable NSPS NO_x emission limit, unless the boiler is also subject to a more stringent permit emission limit, in which case the more stringent emission limit applies. Each auxiliary boiler subject to an emission specification under this subsection is not subject to the emission specifications of subsection (a) or (c) of this section.

(f) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a megawatt (MW) rating greater than or equal to 30 MW and an annual electric output in MW-hours (MW-hr) of greater than or equal to the product of 2,500 hours and the MW rating of the unit, NO_x emissions in excess of a block one-hour average of:

(1) 42 parts per million by volume (ppmv) at 15% oxygen (O_2), dry basis, while firing natural gas; and

(2) 65 ppmv at 15% O_2, dry basis, while firing fuel oil.

(g) No person shall allow the discharge into the atmosphere from any stationary gas turbine used for peaking service with an annual electric output in MW-hr of less than the product of 2,500 hours and the MW rating of the unit NO_x emissions in excess of a block one-hour average of:

(1) 0.20 pound per MMBtu heat input while firing natural gas; and

(2) 0.30 pound per MMBtu heat input while firing fuel oil.

(h) No person shall allow the discharge into the atmosphere from any utility boiler or auxiliary steam boiler subject to the NO_x emission limits specified in subsections (a) - (e) of this section, carbon monoxide (CO) emissions in excess of 400 ppmv at 3.0% O_2, dry (or alternatively, 0.30 pound per MMBtu heat input for gas-fired units, 0.31 lb/MMBtu heat input for oil- fired units, and 0.33 lb/MMBtu for coal-fired units), based on:

(1) a one-hour average for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

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

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

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

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

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

(2) For any unit placed into service after June 9, 1993 and prior to the final compliance date as specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas) or approved under the provisions of §117.540 of this title (relating to Phased Reasonably Available Control Technology (RACT)), as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter, the higher of any permit NO_x emission limit under a permit issued after June 9, 1993 pursuant to Chapter 116 of this title and the emission limits of subsections (a) - (g) of this section shall apply. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.107 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

(l) This section shall no longer apply:

(1) to any utility boiler in the Beaumont/Port Arthur ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.510(a)(2) of this title;

(2) to any utility boiler in the Dallas/Fort Worth ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.510(b)(2) of this title; and

(3) in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.510(c)(2) of this title. For purposes of this paragraph, this means that the RACT emission specifications of this section remain in effect until the emissions allocation for a unit under the Houston/Galveston mass emissions cap are equal or less than the allocation that would be calculated using the RACT emission specifications of this section.

§117.106. Emission Specifications for Attainment Demonstrations.

(a) Beaumont/Port Arthur. The owner or operator of each utility boiler located in the Beaumont/Port Arthur ozone nonattainment area shall ensure that emissions of nitrogen oxides (NO_x) do not exceed 0.10 pound per million Btu (lb/MMBtu) heat input, on a daily average, except as provided in §117.108 of this title (relating to System Cap), or §117.570 of this title (relating to Trading).

(b) Dallas/Fort Worth. The owner or operator of each utility boiler located in the Dallas/Fort Worth (DFW) ozone nonattainment area shall ensure that emissions of NO_x do not exceed: 0.033 lb/MMBtu heat input from boilers which are part of a large DFW system, and 0.06 lb/MMBtu heat input from boilers which are part of a small DFW system, on a daily average, except as provided in §117.108 of this title or §117.570 of this title. The annual heat input exemption of §117.103(2) of this title (relating to Exemptions) is not applicable to a small DFW system.

(c) Houston/Galveston. The owner or operator of each utility boiler, auxiliary steam boiler, or stationary gas turbine located in the Houston/Galveston ozone nonattainment area shall ensure that emissions of NO_x do not exceed the lower of any applicable permit limit or the following rates, in lb/MMBtu heat input, on the basis of daily and 30-day averaging periods as specified in §117.108 of this title, and as specified in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program):

(1) utility boilers:

(A) gas-fired, 0.010; and

(B) coal-fired or oil-fired:

(i) wall-fired, 0.030; and

(ii) tangential-fired, 0.030;

(2) auxiliary steam boilers:

(A) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.010;

(B) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.015; and

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

(3) stationary gas turbines:

(A) rated at 1.0 megawatt (MW) or greater, 0.015; and

(B) rated at less than 1.0 MW:

(i) with initial start of operation on or before December 31, 2000, 0.15; and

(ii) with initial start of operation after December 31, 2000, 0.015; and

(4) as an alternative to the emission specifications in paragraphs (1) - (3) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060.

(d) Related emissions. No person shall allow the discharge into the atmosphere from any unit boiler subject to the NO_x emission limits specified in subsections (a), (b), and (c) of this section:

(1) carbon monoxide (CO) emissions in excess of 400 ppmv at 3.0% O_2, dry (or alternatively, 0.30 lb/MMBtu heat input for gas-fired units, 0.31 lb/MMBtu heat input for oil-fired units, and 0.33 lb/MMBtu for coal-fired units), based on:

(A) a one-hour average for units not equipped with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) for CO; or

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

(2) ammonia emissions in excess of ten ppmv, based on a block one-hour averaging period.

(e) Compliance flexibility.

(1) In the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, an owner or operator may use either of the following alternative methods of compliance with the NO_x emission specifications of this section:

(A) §117.108 of this title; or

(B) §117.570 of this title (relating to Trading).

(2) An owner or operator may petition the executive director for an alternative to the CO or ammonia limits of this section in accordance with §117.121 of this title (relating to Alternative Case Specific Specifications).

(3) Section 117.107 of this title (relating to Alternative System-wide Emission Specifications) and §117.121 of this title are not alternative methods of compliance with the NO_x emission specifications of this section.

(4) In the Houston/Galveston ozone nonattainment area, an owner or operator may not use the alternative methods specified in §117.570 of this title to comply with the NO_x emission specifications of this section. In addition, the following requirements apply.

(A) For units which meet the definition of electric generating facility (EGF), the owner or operator must use both the alternative methods specified in §117.108 of this title and the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) to comply with the NO_x emission specifications of this section.

(B) For units which do not meet the definition of EGF, the owner or operator must use the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title to comply with the NO_x emission specifications of this section.

§117.108. System Cap.

(a) An owner or operator of an electric generating facility (EGF) in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment areas may achieve compliance with the nitrogen oxides (NO_x) emission limits of §117.106 of this title (relating to Emission Specifications for Attainment Demonstrations) by achieving equivalent NO_x emission reductions obtained by compliance with a daily and 30-day system cap emission limitation in accordance with the requirements of this section. An owner or operator of an electric generating facility in the Houston/Galveston ozone nonattainment area must comply with a daily and 30-day system cap emission limitation in accordance with the requirements of this section.

(b) Each EGF within an electric power generating system, as defined in §117.10(12)(A) of this title (relating to Definitions), that would otherwise be subject to the NO_x emission rates of §117.106 of this title must be included in the system cap.

(c) The system cap shall be calculated as follows.

(1) A rolling 30-day average emission cap shall be calculated using the following equation.
Figure: 30 TAC §117.108(c)(1)

(2) A maximum daily cap shall be calculated using the following equation.
Figure: 30 TAC §117.108(c)(2) (No change.)

(3) Each EGF in the system cap shall be subject to the emission limits of both paragraphs (1) and (2) of this subsection at all times.

(d) The NO_x emissions monitoring required by §117.113 of this title (relating to Continuous Demonstration of Compliance) for each EGF in the system cap shall be used to demonstrate continuous compliance with the system cap.

(e) For each operating EGF, 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); or

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

(2) use Appendix E monitoring in accordance with §117.113(d) of this title;

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

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

(B) use calculations in accordance with §117.113(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 block one-hour emission rate as measured by the 30-day testing.

(f) The owner or operator of any EGF subject to a system cap shall maintain daily records indicating the NO_x emissions and fuel usage from each EGF and summations of total NO_x emissions and fuel usage for all EGFs under the system cap on a daily basis. Records shall also be retained in accordance with §117.119 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(g) The owner or operator of any EGF subject to a system cap shall report any exceedance of the system cap emission limit within 48 hours to the appropriate regional office. The owner or operator shall then follow up within 21 days of the exceedance with a written report to the regional office which includes an analysis of the cause for the exceedance with appropriate data to demonstrate the amount of emissions in excess of the applicable limit and the necessary corrective actions taken by the company to assure future compliance. Additionally, the owner or operator shall submit semiannual reports for the monitoring systems in accordance with §117.119 of this title.

(h) The owner or operator of any EGF subject to a system cap shall demonstrate initial compliance with the system cap in accordance with the schedule specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas).

(i) For the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, an EGF which is permanently retired or decommissioned and rendered inoperable may be included in the source cap emission limit, provided that the permanent shutdown occurred after January 1, 1999. For the Houston/Galveston ozone nonattainment area, an EGF which is permanently retired or decommissioned and rendered inoperable may be included in the source cap emission limit, provided that the permanent shutdown occurred after January 1, 2000. 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 EGF 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 the EPA that actual emissions were less than maximum emissions during such periods.

§117.114. Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration.

(a) Monitoring requirements. The owner or operator of units which are subject to the emission limits of §117.106(c) of this title (relating to Emission Specifications for Attainment Demonstrations) must comply with the following monitoring requirements.

(1) The nitrogen oxides (NO_x) monitoring requirements of §117.113(a), (c) - (f) of this title (relating to Continuous Demonstration of Compliance) apply.

(2) The carbon monoxide (CO) monitoring requirements of §117.113(b) of this title apply.

(3) The totalizing fuel flow meter requirements of §117.113(h) of this title apply.

(4) Installation of monitors shall be performed in accordance with the schedule specified in §117.510(c)(2) of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas).

(b) Testing requirements. The owner or operator of units which are subject to the emission limits of §117.106(c) of this title must test the units as specified in §117.111 of this title (relating to Initial Demonstration of Compliance) in accordance with the schedule specified in §117.510(c)(2) of this title.

(c) Emission allowances.

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

(2) For units not operating with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS), the following apply.

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

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

(C) The NO_x emission rate determined by the retesting shall establish a new emission factor to be used to calculate actual emissions instead of the previously determined emission factor used to calculate actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

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

§117.116. Final Control Plan Procedures for Attainment Demonstration Emission Specifications.

(a) The owner or operator of utility boilers listed in §117.101 of this title (relating to Applicability) at a major source of nitrogen oxides (NO_x) shall submit to the executive director a final control report to show compliance with the requirements of §117.106 of this title (relating to Emission Specifications for Attainment Demonstrations). The report must include:

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

(A) §117.106 of this title; or

(B) §117.108 of this title (relating to System Cap); and as applicable,

(C) §117.570 of this title (relating to Trading);

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

(3) the emissions measured by testing required in §117.111 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 §117.111 of this title which is not being submitted concurrently with the final compliance report; and

(5) the specific rule citation for any utility boiler with a claimed exemption from the emission specification of §117.106 of this title.

(b) For sources complying with §117.108 of this title, in addition to the requirements of subsection (a) of this section, the owner or operator shall submit:

(1) the calculations used to calculate the 30-day average and maximum daily system cap allowable emission rates;

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

(A) the average daily heat input H_i specified in §117.108(c)(1) of this title;

(B) the maximum daily heat input H_{mi} specified in §117.108(c)(2) of this title;

(C) the method of monitoring emissions; and

(D) 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 values of H_i and H_{mi}.

(c) The report must be submitted by the applicable date specified for final control plans in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas). The plan must be updated with any emission compliance measurements submitted for units using continuous emissions monitoring system or predictive emissions monitoring system and complying with the system cap rolling 30-day average emission limit, according to the applicable schedule given in §117.510 of this title.

§117.121. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), or the carbon monoxide (CO) or ammonia limits of §117.106(d) of this title (relating to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.105 of this title or the CO or ammonia limits in §117.106(d) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) must determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through system-wide averaging at maximum capacity.

(b) Any person affected by the executive director's decision to deny an alternative case specific emission specification may file a motion for reconsideration. The requirements of §50.39 of this title (relating to Motion for Reconsideration) or §50.139 of this title (relating to Overturn Executive Director's Decision) apply. However, only a person affected may file a motion for reconsideration. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the EPA in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas).

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009084
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

DIVISION 2. UTILITY ELECTRIC GENERATION IN EAST AND CENTRAL TEXAS

30 TAC §117.138

STATUTORY AUTHORITY

The amendment is 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; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air, such as the SIP; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009085
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

DIVISION 3. INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL COMBUSTION SOURCES IN OZONE NONATTAINMENT AREAS

30 TAC §§117.201, 117.203, 117.205-117.208, 117.210, 117.211, 117.213, 117.214, 117.216, 117.219, 117.221

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; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air, such as the SIP; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

§117.201. Applicability.

The provisions of this division (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas), shall apply to the following units located at any major stationary source of nitrogen oxides located within the Beaumont/Port Arthur, Dallas/Fort Worth, or Houston/Galveston ozone nonattainment areas:

(1) industrial, commercial, or institutional boilers and process heaters;

(2) stationary gas turbines;

(3) stationary internal combustion engines;

(4) fluid catalytic cracking units (including carbon monoxide (CO) boilers, CO furnaces, and catalyst regenerator vents);

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

(6) duct burners used in turbine exhaust ducts;

(7) pulping liquor recovery furnaces;

(8) lime kilns;

(9) lightweight aggregate kilns;

(10) heat treating furnaces and reheat furnaces;

(11) magnesium chloride fluidized bed dryers; and

(12) incinerators.

§117.203. Exemptions.

(a) Units exempted from the provisions of this division (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas), except as may be specified in §117.209(c)(1) of this title (relating to Initial Control Plan Procedures), include the following:

(1) any new units placed into service after November 15, 1992, except for new units which were placed into service as functionally identical replacement for existing units subject to the provisions of this division as of June 9, 1993. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced;

(2) any commercial, institutional, or industrial boiler or process heater with a maximum rated capacity of less than 40 million Btu per hour (MMBtu/hr);

(3) heat treating furnaces and reheat furnaces. This exemption shall no longer apply to any heat treating furnace or reheat furnace with a maximum rated capacity of 20 MMBtu/hr or greater in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas);

(4) flares, incinerators, pulping liquor recovery furnaces, sulfur recovery units, sulfuric acid regeneration units, and sulfur plant reaction boilers. This exemption shall no longer apply to the following units in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title:

(A) incinerators with a maximum rated capacity of 40 MMBtu/hr or greater; and

(B) pulping liquor recovery furnaces;

(5) dryers, kilns, or ovens used for drying, baking, cooking, calcining, and vitrifying. This exemption shall no longer apply to the following units in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title:

(A) magnesium chloride fluidized bed dryers; and

(B) lime kilns and lightweight aggregate kilns;

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

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

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

(7) stationary gas turbines with a megawatt (MW) rating of less than 1.0 MW;

(8) stationary internal combustion engines which are:

(A) located in the Houston/Galveston ozone nonattainment area with a horsepower (hp) rating of less than 150 hp; or

(B) located in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment area with a hp rating of less than 300 hp;

(9) any boiler or process heater with a maximum rated capacity of 2.0 MMBtu/hr or less; and

(10) diesel-fired stationary internal combustion engines.

(b) The exemptions in paragraphs (1), (2), (6)(B), (7), and (8)(A) of subsection (a) shall no longer apply in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations specified in §117.520 of this title.

(c) Upon issuance of a standard permit by the commission for small (ten MW or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid, combustion sources registered under that permit are exempt from this chapter.

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

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

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

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

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

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

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

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

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

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

(1) gas-fired boilers, as follows:

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

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

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

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

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

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

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

(A) based on air preheat temperature:

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

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

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

(B) based on firebox temperature:

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

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

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

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

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

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

(6) for any gas-fired boiler or process heater firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, a multiplier of up to 1.25 times the appropriate emission limit in this subsection may be used for that eight-hour period. The total hydrogen volume in all gaseous fuel streams will be divided by the total gaseous fuel flow volume to determine the volume percent of hydrogen in the fuel supply. The multiplier may not be used to increase limits set by permit. The following equation shall be used by an owner or operator using a gas-fired boiler or process heater which is subject to this paragraph and one of the rolling 30-day averaging period emission limitations contained in paragraph (1) or (2) of this subsection to calculate an emission limitation for each rolling 30-day period:
Figure: 30 TAC §117.205(b)(6)

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

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

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

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

(c) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a MW rating greater than or equal to 10.0 MW, emissions in excess of a block one-hour average concentration of 42 parts per million by volume (ppmv) NO_x and 132 ppmv carbon monoxide (CO) at 15% oxygen (O_2), dry basis. For stationary gas turbines equipped with CEMS or PEMS for CO, the owner or operator may elect to comply with the CO limit of this subsection using a 24-hour rolling average.

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

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

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

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

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

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

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

(B) a monitoring system which:

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

(I) may be adjusted by engine testing; and

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

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

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

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

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

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

(g) No person shall allow the discharge into the atmosphere from any unit subject to a NO_x emission limit in this section, (including an alternative to the NO_x limit in this section under §117.207 or §117.223 of this title), ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

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

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

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

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

(4) fluid catalytic cracking units (including CO boilers, CO furnaces, and catalyst regenerator vents);

(5) duct burners used in turbine exhaust ducts;

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

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

(8) any new units placed into service after November 15, 1992, except for new units which were placed into service as functionally identical replacement for existing units subject to the provisions of this division as of June 9, 1993. Any emission credits resulting from the operation of such replacement units shall be limited to the cumulative maximum rated capacity of the units replaced;

(9) stationary gas turbines and engines, which are demonstrated to operate less than 850 hours per year, based on a rolling 12-month average; and

(10) stationary internal combustion engines which are:

(A) located in the Houston/Galveston ozone nonattainment area with a horsepower (hp) rating of less than 150 hp; or

(B) located in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment area with a hp rating of less than 300 hp.

(i) This section shall no longer apply:

(1) to any gas-fired boiler or process heater in the Beaumont/Port Arthur ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.520(a)(3) of this title; and

(2) in the Houston/Galveston ozone nonattainment area after the appropriate compliance date(s) for emission specifications for attainment demonstrations given in §117.520(c)(2) of this title. For purposes of this paragraph, this means that the RACT emission specifications of this section remain in effect until the emissions allocation for a unit under the Houston/Galveston mass emissions cap are equal or less than the allocation that would be calculated using the RACT emission specifications of this section.

§117.206. Emission Specifications for Attainment Demonstrations.

(a) Beaumont/Port Arthur. No person shall allow the discharge into the atmosphere from any gas-fired boiler or process heater with a maximum rated capacity equal to or greater than 40 million (MM) Btu/hr in the Beaumont/Port Arthur ozone nonattainment area, emissions of nitrogen oxides (NO_x) in excess of the following, except as provided in subsections (f) and (g) of this section:

(1) boilers, 0.10 pound (lb) NO_x per MMBtu of heat input; and

(2) process heaters, 0.08 lb NO_x per MMBtu of heat input.

(b) Dallas/Fort Worth. No person shall allow the discharge into the atmosphere in the Dallas/Fort Worth ozone nonattainment area, emissions in excess of the following, except as provided in subsections (f) and (g) of this section:

(1) gas-fired boilers with a maximum rated capacity equal to or greater than 40 MMBtu/hr, 30 parts per million by volume (ppmv) NO_x, at 3.0% oxygen (O_2), dry basis; and

(2) gas-fired and gas/liquid-fired, lean-burn, stationary reciprocating internal combustion engines rated 300 horsepower (hp) or greater, 2.0 grams NO_x per horsepower hour (g NO_x/hp-hr) and 3.0 g carbon monoxide (CO)/hp-hr.

(c) Houston/Galveston. In the Houston/Galveston ozone nonattainment area, the emission rate values used to determine allocations for Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) shall be the lower of any applicable permit limit or the following:

(1) gas-fired boilers:

(A) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.010 lb NO_x per MMBtu;

(B) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.015 lb NO_x per MMBtu; and

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

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

(A) 13 ppmv NO_x at 0.0% O_2, dry basis;

(B) a 90% NO_x reduction of the exhaust concentration used to calculate the June - August 1997 daily NO_x emissions; or

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

(i) install and certify a NO_x CEMS or PEMS as specified in §117.213(e) or (f) of this title (relating to Continuous Demonstration of Compliance) no later than June 30, 2001;

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

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

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

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

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

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

(i) 0.030 lb NO_x per MMBtu; or

(ii) an 80% reduction from the emission factor used to calculate the June - August 1997 daily NO_x emissions;

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

(5) wood fuel-fired boilers, 0.046 lb NO_x per MMBtu;

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

(7) oil-fired boilers, 2.0 lb NO_x per 1,000 gallons of oil burned;

(8) process heaters:

(A) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.010 lb NO_x per MMBtu;

(B) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.015 lb NO_x per MMBtu; and

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

(9) stationary, reciprocating internal combustion engines:

(A) gas-fired rich-burn engines, 0.17 g NO_x/hp-hr;

(B) gas-fired lean-burn engines, 0.50 g NO_x/hp-hr, except as specified in subparagraph (C) of this paragraph; and

(C) dual-fuel engines:

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

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

(10) stationary gas turbines:

(A) rated at 1.0 megawatt (MW) or greater, 0.015 lb NO_x per MMBtu; and

(B) rated at less than 1.0 MW:

(i) with initial start of operation on or before December 31, 2000, 0.15 lb NO_x per MMBtu; and

(ii) with initial start of operation after December 31, 2000, 0.015 lb NO_x per MMBtu;

(11) duct burners used in turbine exhaust ducts, 0.015 lb NO_x per MMBtu;

(12) pulping liquor recovery furnaces, either:

(A) 0.050 lb NO_x per MMBtu; or

(B) 1.08 lb NO_x per air-dried ton of pulp (ADTP);

(13) kilns:

(A) lime kilns, 0.66 lb NO_x per ton of calcium oxide (CaO); and

(B) lightweight aggregate kilns, 0.76 lb NO_x per ton of product;

(14) metallurgical furnaces:

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

(B) reheat furnaces, 0.062 lb NO_x per MMBtu;

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

(16) incinerators, either of the following:

(A) an 80% reduction from the emission factor used to calculate the June - August 1997 daily NO_x emissions; or

(B) 0.030 lb NO_x per MMBtu; and

(17) as an alternative to the emission specifications in paragraphs (1) - (16) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb NO_x per MMBtu.

(d) NO_x averaging time.

(1) In the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, the emission limits of subsections (a) and (b) of this section shall apply:

(A) if the unit is operated with a NO_x CEMS or PEMS under §117.213 of this title, either as:

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

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

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

(B) if the unit is not operated with a NO_x CEMS or PEMS under §117.213 of this title, a block one-hour average, in the units of the applicable standard. Alternatively for boilers and process heaters, the emission limits may be applied in lbs per hour, as specified in subparagraph (A)(iii) of this paragraph.

(2) In the Houston/Galveston ozone nonattainment area, the averaging time for the emission limits of subsection (c) of this section shall be as specified in Chapter 101, Subchapter H, Division 3 of this title, except that electric generating facilities (EGFs) shall also comply with the daily and 30-day system cap emission limitations of §117.210 of this title (relating to System Cap).

(e) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to NO_x emission specifications in subsection (a), (b), or (c) of this section, emissions in excess of the following, except as provided in §117.221 of this title (relating to Alternative Case Specific Specifications) or paragraph (3) or (4) of this subsection:

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

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

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

(2) ammonia emissions, ten ppmv on a block one-hour averaging period;

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

(A) lightweight aggregate kilns; and

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

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

(A) stationary internal combustion engines subject to subsection (b)(2) of this section or §117.205(e) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT));

(B) BIF units which were regulated as existing facilities by the EPA at 40 CFR 266, Subpart H (as was in effect on June 9, 1993) and which are subject to subsection (c)(3) of this section; and

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

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

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

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

(f) Compliance flexibility.

(1) In the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, an owner or operator may use any of the following alternative methods to comply with the NO_x emission specifications of this section:

(A) §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications);

(B) §117.223 of this title (relating to Source Cap); or

(C) §117.570 (relating to Trading).

(2) Section 117.221 of this title is not an applicable method of compliance with the NO_x emission specifications of this section.

(3) An owner or operator may petition the executive director for an alternative to the CO or ammonia limits of this section in accordance with §117.221 of this title.

(4) In the Houston/Galveston ozone nonattainment area, an owner or operator may not use the alternative methods specified in §§117.207, 117.223, and 117.570 of this title to comply with the NO_x emission specifications of this section. The owner or operator shall use the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title to comply with the NO_x emission specifications of this section, except that EGFs shall also comply with the daily and 30-day system cap emission limitations of §117.210 of this title.

(g) Exemptions. Units exempted from the emissions specifications of this section include the following in the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas:

(1) any industrial, commercial, or institutional boiler or process heater with a maximum rated capacity less than 40 MMBtu/hr; and

(2) units exempted from emission specifications in §117.205(h)(2) - (5) of this title.

(h) Prohibition of circumvention. In the Houston/Galveston ozone nonattainment area, the owner or operator of units which utilize liquid or gaseous streams containing chemical-bound nitrogen as a source of fuel or combustion air shall not direct these streams to flares or other units which are not subject to an emission specification in subsection (c) of this section, unless:

(1) the unit which receives the chemical-bound nitrogen stream is opted into the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title; and

(2) NO_x emissions from this opt-in unit are determined using a CEMS or PEMS which meets the requirements of §117.213(e) or (f) of this title or through stack testing which meets the requirements of §117.211(e) of this title (relating to Initial Demonstration of Compliance).

§117.208. Operating Requirements.

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

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

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

(d) All units subject to the emission limitations of §§117.205, 117.206(a) and (b), 117.207, or 117.223 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Emission Specifications for Attainment Demonstrations; Alternative Plant-wide Emission Specifications; and Source Cap) shall be operated so as to minimize NO_x emissions, consistent with the emission control techniques selected, over the unit's operating or load range during normal operations. Such operational requirements include the following.

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

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

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

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

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

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

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

§117.210. System Cap.

(a) The owner or operator of each electric generating facility (EGF) in the Houston/Galveston ozone nonattainment area must comply with a daily and 30-day system cap emission limitation for nitrogen oxides (NO_x) in accordance with the requirements of this section. EGFs are not subject to this section if electric output is entirely dedicated to industrial customers. "Entirely dedicated" may include up to two weeks per year of service to the electric grid when the industrial customers' load sources are not operating.

(b) Each EGF that is subject to the NO_x emission rates of §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations) must be included in the system cap.

(c) The system cap shall be calculated as follows.

(1) A rolling 30-day average emission cap shall be calculated using the following equation.
Figure: 30 TAC §117.210(c)(1)

(2) A maximum daily cap shall be calculated using the following equation.
Figure: 30 TAC §117.210(c)(2)

(3) Each EGF in the system cap shall be subject to the emission limits of both paragraphs (1) and (2) of this subsection at all times.

(d) The NO_x emissions monitoring required by §117.213 of this title (relating to Continuous Demonstration of Compliance) for each EGF in the system cap shall be used to demonstrate continuous compliance with the system cap.

(e) For each operating EGF, 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 CFR 75, use the missing data procedures specified in 40 CFR 75, Subpart D (Missing Data Substitution Procedures); or

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

(2) use Appendix E monitoring in accordance with §117.113(d) of this title (relating to Continuous Demonstration of Compliance);

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

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

(B) use calculations in accordance with §117.113(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 block one-hour emission rate as measured by the 30-day testing.

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

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

(h) The owner or operator of any EGF subject to a system cap shall demonstrate initial compliance with the system cap in accordance with the schedule specified in §117.520 of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas).

(i) An EGF which is permanently retired or decommissioned and rendered inoperable may be included in the source cap emission limit, provided that the permanent shutdown occurred after January 1, 2000. 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 (relating to Control of Air Pollution by Permits for New Construction or Modification) 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 EGF 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 the EPA that actual emissions were less than maximum emissions during such periods.

§117.213. Continuous Demonstration of Compliance.

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

(1) The units are the following:

(A) for units which are subject to §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), and for units in the Beaumont/Port Arthur (BPA) and Dallas/Fort Worth (DFW) ozone nonattainment areas which are subject to §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations):

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

(I) boilers;

(II) process heaters;

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

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

(ii) stationary, reciprocating internal combustion engines not exempt by §117.203(a)(6) or (8) of this title (relating to Exemptions), or §117.205(h)(9) or (10) of this title;

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

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

(B) for units in the Houston/Galveston (HGA) ozone nonattainment area which are subject to §117.206 of this title:

(i) boilers (excluding wood-fired boilers);

(ii) process heaters;

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

(iv) duct burners used in turbine exhaust ducts;

(v) stationary, reciprocating internal combustion engines;

(vi) stationary gas turbines;

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

(viii) lime kilns;

(ix) lightweight aggregate kilns;

(x) heat treating furnaces;

(xi) reheat furnaces;

(xii) magnesium chloride fluidized bed dryers; and

(xiii) incinerators.

(2) As an alternative to the fuel flow monitoring requirements of this subsection, units operating with a nitrogen oxides (NO_x) and diluent continuous emissions monitoring system (CEMS) under subsection (e) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 CFR 60, Appendix B, Performance Specification 6 or 40 CFR 75, Appendix A.

(b) Oxygen (O_2) monitors.

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

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

(B) process heaters with a rated heat input:

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

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

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

(A) units listed in §117.205(h)(3) - (5) and (8) - (10) of this title;

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

(C) wood-fired boilers.

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

(c) NO_x monitors.

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

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

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

(C) boilers and process heaters located in the Beaumont/Port Arthur ozone nonattainment area which are vented through a common stack and the total rated heat input from the units combined is greater than or equal to 250 MMBtu/hr and the annual heat input combined is greater than $2.2(10^{11})$ Btu/yr;

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

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

(F) units for which the owner or operator elects to comply with the NO_x emission specifications of §117.205 or §117.206(a) or (b) of this title using a pound per MMBtu limit on a 30-day rolling average;

(G) lime kilns and lightweight aggregate kilns in HGA; and

(H) units with a rated heat input greater than or equal to 100 MMBtu/hr which are subject to §117.206(c) of this title.

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

(A) for purposes of §117.205 or §117.206(a) or (b) of this title, units listed in §117.205(h)(3) - (5) and (8) - (10) of this title; and

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

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

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

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

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

(2) sample CO as follows:

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

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

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

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

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

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

(A) Section 60.13;

(B) Appendix B:

(i) Performance Specification 2, for NO_x;

(ii) Performance Specification 3, for diluent; and

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

(C) After the final compliance date, audits in accordance with §5.1 of Appendix F, quality assurance procedures for NO_x, CO and diluent analyzers, 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 §5.1.1.

(2) Monitor diluent, either O_2 or CO_2, unless using an exhaust flow meter as provided in subsection (a)(2) of this section.

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

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

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

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

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

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

(2) Monitor diluent, either O_2 or CO_2:

(A) using a CEMS

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

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

(B) using a PEMS.

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

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

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

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

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

(A) perform the following alternative initial certification tests:

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

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

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

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

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

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

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

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

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

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

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

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

(i) at normal load operations;

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

(iii) at the following frequency:

(I) semiannually; or

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

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

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

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

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

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

(1) Engines not using NO_x CEMS or PEMS.

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

(B) Sample:

(i) on a biennial calendar basis; or

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

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

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

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

(-b-) an estimate of the date of the next required sampling.

(C) Gas-fired emergency generators are not required to conduct the testing specified in subparagraph (B) of this paragraph.

(2) Engines using NO_x CEMS or PEMS. Engines which use a chemical reagent for reduction of NO_x shall monitor in accordance with subsection (c)(1)(E) of this section and shall comply with the applicable requirements of this section for CEMS and PEMS.

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

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

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

(A) The system shall be accurate to within ± 5.0%.

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

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

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

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

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

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

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

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

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

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

(k) Data used for compliance.

(1) After the initial demonstration of compliance required by §117.211 of this title, the methods required in this section shall be used to determine compliance with the emission specifications of §117.205 or §117.206(a) or (b) of this title. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission limitations.

(2) For units subject to the emission specifications of §117.206(c) of this title, the methods required in this section and §117.214 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) shall be used in conjunction with the requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) to determine compliance. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission limitations.

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

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

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

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

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

§117.214. Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration.

(a) Monitoring requirements. The owner or operator of units which are subject to the emission limits of §117.206(c) of this title (relating to Emission Specifications for Attainment Demonstrations) must comply with the following monitoring requirements.

(1) The nitrogen oxides (NO_x) monitoring requirements of §117.213(c), (e), and (f) of this title (relating to Continuous Demonstration of Compliance) apply.

(2) The carbon monoxide (CO) monitoring requirements of §117.213(d) of this title apply.

(3) The totalizing fuel flow meter requirements of §117.213(a) of this title apply.

(4) Installation of monitors shall be performed in accordance with the schedule specified in §117.520(c)(2) of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas).

(b) Testing requirements.

(1) The owner or operator of units which are subject to the emission limits of §117.206(c) of this title must test the units as specified in §117.211 of this title (relating to Initial Demonstration of Compliance) in accordance with the schedule specified in §117.520(c)(2) of this title.

(2) Each stationary internal combustion engine shall be checked for proper operation of the engine by recorded measurements of NO_x and CO emissions at least quarterly and as soon as practicable within two weeks after each occurrence of engine maintenance which may reasonably be expected to increase emissions, oxygen (O_2) sensor replacement, or catalyst cleaning or catalyst replacement. Stain tube indicators specifically designed to measure NO_x concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x analyzers shall also be acceptable for this documentation. Quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours. This exemption does not diminish the requirement to test emissions after the installation of controls, major repair work, and any time the owner or operator believes emissions may have changed.

(c) Emission allowances.

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

(2) For units not operating with continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS), the following apply.

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

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

(C) The NO_x emission rate determined by the retesting shall establish a new emission factor to be used to calculate actual emissions instead of the previously determined emission factor used to calculate actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

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

§117.216. Final Control Plan Procedures for Attainment Demonstration Emission Specifications.

(a) The owner or operator of units listed in §117.206(a) and (b) of this title (relating to Emission Specifications for Attainment Demonstrations) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.206 of this title. The report must include:

(1) the section under which NO_x compliance is being established, either:

(A) Section 117.206 of this title;

(B) Section 117.223 of this title (relating to Source Cap); or

(C) Section 117.570 of this title (relating to Trading);

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

(3) the emissions measured by testing required in §117.211 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 §117.211 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 §117.206 of this title.

(b) For sources complying with §117.223 of this title, in addition to the requirements of subsection (a) of this section, the owner or operator shall submit:

(1) the calculations used to calculate the 30-day average and maximum daily source cap allowable emission rates;

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

(A) the average daily heat input H_i specified in §117.223(b)(1) and (k) or (l) of this title;

(B) the maximum daily heat input H_{mi} specified in §117.223(b)(2) and (k) or (l) of this title;

(C) the method of monitoring emissions; and

(D) 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 values of H_i and H_{mi}.

(c) The report must be submitted to the executive director by the applicable date specified for final control plans in §117.520(a) or (b) of this title (relating to Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas). The plan must be updated with any emission compliance measurements submitted for units using continuous emissions monitoring system or predictive emissions monitoring system and complying with the source cap rolling 30-day average emission limit, according to the applicable schedule given in §117.520 of this title.

§117.219. Notification, Recordkeeping, and Reporting Requirements.

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

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

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

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

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

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

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

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or water- to-fuel or steam-to-fuel ratio monitoring system under §117.213 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations of this division (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) and the monitoring system performance. For sources in the Houston/Galveston ozone nonattainment area in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), which are no longer subject to the emission limitations of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), the report is only a monitoring system report as specified in paragraph (3) of this subsection. All reports shall be postmarked or received by the 30th day following the end of each calendar semiannual period. Written reports shall include the following information:

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

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

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

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

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

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

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

(e) Reporting for engines. The owner or operator of any rich-burn engine subject to the emission limitations in §§117.205, 117.206 (relating to Emission Specifications for Attainment Demonstrations), or 117.207 (relating to Alternative Plant-wide Emission Specifications) of this title shall report in writing to the executive director on a quarterly basis any excess emissions and the air- fuel ratio monitoring system performance. All reports shall be postmarked or received by the 30th day following the end of each calendar semiannual period. Written reports shall include the following information:

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

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

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

(1) for each unit subject to §117.213(a) of this title, records of annual fuel usage;

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

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

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

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

(ii) pounds or tons per day; or

(C) daily emissions and fuel usage (or stack exhaust flow) for units subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title. Emissions must be recorded in units of:

(i) lb/MMBtu heat input or in the units of the applicable emission specification in §117.206(c) of this title; and

(ii) pounds or tons per day;

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

(A) emissions measurements required by:

(i) §117.208(d)(7) of this title; and

(ii) §117.213(g) of this title; and

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

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

(A) pounds of steam or water injected;

(B) pounds of fuel consumed; and

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

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

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

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

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

(7) Records of carbon monoxide measurements specified in §117.213(d)(2) of this title;

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

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

§117.221. Alternative Case Specific Specifications.

(a) Where a person can demonstrate that an affected unit cannot attain the applicable requirements of §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or the carbon monoxide (CO) or ammonia limits of §117.206(e) of this title (relating to Emission Specifications for Attainment Demonstrations), the executive director may approve emission specifications different from §117.205 of this title or the CO or ammonia limits in §117.206(e) of this title for that unit. The executive director:

(1) shall consider on a case-by-case basis the technological and economic circumstances of the individual unit;

(2) must determine that such specifications are the result of the lowest emission limitation the unit is capable of meeting after the application of reasonably available control technology; and

(3) in determining whether to approve alternative emission specifications, may take into consideration the ability of the plant at which the unit is located to meet emission specifications through plant-wide averaging at maximum capacity.

(b) Any person affected by the executive director's decision to deny an alternative case specific emission specification may file a motion for reconsideration. The requirements of §50.39 of this title (relating to Motion for Reconsideration) or §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) apply. However, only a person affected may file a motion for reconsideration. Executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by EPA in cases where specified criteria for determining equivalency have not been clearly identified in applicable sections of this division (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas).

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009086
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

SUBCHAPTER D. SMALL COMBUSTION SOURCES
DIVISION 2. BOILERS, PROCESS HEATERS, AND STATIONARY ENGINES AT MINOR SOURCES

30 TAC §§117.471, 117.473, 117.475, 117.478, 117.479

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; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air, such as the SIP; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

§117.473. Exemptions.

(a) This division (relating to Boilers, Process Heaters, and Stationary Engines at Minor Sources) does not apply to the following:

(1) boilers and process heaters with a maximum rated capacity of 2.0 million British thermal units per hour (MMBtu/hr) or less; and

(2) the following engines:

(A) engines with a horsepower (hp) rating of 50 hp or less;

(B) engines used in research and testing;

(C) engines used for purposes of performance verification and testing;

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

(E) engines operated exclusively for firefighting and/or flood control;

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

(G) engines used directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals;

(H) emergency generators that do not operate more than 100 hours per calendar year, provided that records are maintained as specified in §117.479(h) of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements); and

(I) diesel-fired engines.

(b) At any stationary source of nitrogen oxides (NO_x) which is not subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the following are exempt from the requirements of this division, except for the totalizing fuel flow requirements of §117.479(a), (d), and (g)(1) of this title:

(1) any boiler or process heater with a maximum rated capacity greater than 2.0 MMBtu/hr and less than 5.0 MMBtu/hr that has an annual heat input less than or equal to 1.8 (10^9) Btu per calendar year; and

(2) any boiler or process heater with a maximum rated capacity equal to or greater than 5.0 MMBtu/hr that has an annual heat input less than or equal to 9.0 (10^9) Btu per calendar year.

(c) Upon issuance of a standard permit by the commission for small (ten megawatts or less) electric generating units that generate electricity for use by the owner and/or generate power to be sold to the electric grid, combustion sources registered under that permit are exempt from this chapter.

§117.475. Emission Specifications.

(a) For sources which are subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the nitrogen oxides (NO_x) emission rate values used to determine allocations for Chapter 101, Subchapter H, Division 3 of this title shall be the lower of any applicable permit limit or the limits in subsection (c) of this section. The averaging time shall be as specified in Chapter 101, Subchapter H, Division 3 of this title.

(b) For sources which are not subject to Chapter 101, Subchapter H, Division 3 of this title, NO_x emissions are limited to the lower of any applicable permit limit or the limits in subsection (c) of this section. The averaging time shall be as follows:

(1) if the boiler, process heater, or engine is operated with a NO_x continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.479(c) of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements), either as:

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

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

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

(2) if the unit is not operated with a NO_x CEMS or PEMS under §117.479(c) of this title, a block one-hour average, in the units of the applicable standard.

(c) No person shall allow the discharge of NO_x emissions into the atmosphere in excess of the following rates:

(1) from boilers and process heaters, 0.036 lb/MMBtu heat input (or alternatively, 30 parts per million by volume (ppmv), at 3.0% oxygen (O_2), dry basis);

(2) from stationary, gas-fired, reciprocating internal combustion engines, 0.50 gram per horsepower- hour (g/hp-hr); and

(3) as an alternative to the emission specifications in paragraphs (1) and (2) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu heat input.

§117.478. Operating Requirements.

(a) The owner or operator shall operate any boiler, process heater, or engine subject to the emission limitations of §117.475 of this title (relating to Emission Specifications) in compliance with those limitations.

(b) All boilers, process heaters, and engines subject to the emission limitations of §117.475 of this title shall be operated so as to minimize nitrogen oxides (NO_x) emissions, consistent with the emission control techniques selected, over the unit's operating or load range during normal operations. Such operational requirements include the following.

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

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

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

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

(5) Each stationary internal combustion engine shall be checked for proper operation of the engine by recorded measurements of NO_x and CO emissions at least quarterly and as soon as practicable within two weeks after each occurrence of engine maintenance which may reasonably be expected to increase emissions, O_2 sensor replacement, catalyst cleaning, or catalyst replacement. Stain tube indicators specifically designed to measure NO_x concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x analyzers shall also be acceptable for this documentation. Quarterly emission testing is not required for those engines whose monthly run time does not exceed ten hours. This exemption does not diminish the requirement to test emissions after the installation of controls, major repair work, and any time the owner or operator believes emissions may have changed.

§117.479. Monitoring, Recordkeeping, and Reporting Requirements.

(a) Totalizing fuel flow meters.

(1) The owner or operator of each boiler, process heater, or engine subject to the emission limitations of §117.475 of this title (relating to Emission Specifications) 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.

(2) As an alternative to the fuel flow monitoring requirements of this subsection, units operating with a nitrogen oxides (NO_x) and diluent continuous emissions monitoring system (CEMS) under subsection (c) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (CFR) 60, Appendix B, Performance Specification 6 or 40 CFR 75, Appendix A.

(b) Oxygen (O_2) monitors. If the owner or operator installs an O_2 monitor, the criteria in §117.213(e) of this title (relating to Continuous Demonstration of Compliance) should be considered the appropriate guidance for the location and calibration of the monitor.

(c) NO_x monitors. If the owner or operator installs a CEMS or predictive emissions monitoring system (PEMS), it shall meet the requirements of §117.213(e) or (f) of this title.

(d) Monitor installation schedule. Installation of monitors shall be performed in accordance with the schedule specified in §117.534 of this title (relating to Compliance Schedule for Boilers, Process Heaters, and Stationary Engines at Minor Sources).

(e) Testing requirements. The owner or operator of any boiler, process heater, or engine subject to the emission limitations of §117.475 of this title shall comply with the following testing requirements.

(1) Each boiler, process heater, or engine shall be tested for NO_x, carbon monoxide (CO), and O_2 emissions.

(2) Boilers, process heaters, and engines which inject urea or ammonia into the exhaust stream for NO_x control shall be tested for ammonia emissions.

(3) All testing shall be conducted while operating at the maximum rated capacity, or as near thereto as practicable. Compliance shall be determined by the average of three one-hour emission test runs, using the following test methods:

(A) Test Method 7E or 20 (40 CFR 60, Appendix A) for NO_x;

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

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

(D) Test Method 2 (40 CFR 60, Appendix A) for exhaust gas flow and following the measurement site criteria of Test Method 1, Section 2.1 (40 CFR 60, Appendix A), or Test Method 19 (40 CFR 60, Appendix A) for exhaust gas flow in conjunction with the measurement site criteria of Performance Specification 2, Section 3.2 (40 CFR 60, Appendix B);

(E) American Society of Testing and Materials (ASTM) Method D1945-91 or ASTM Method D3588- 93 for fuel composition; ASTM Method D1826-88 or ASTM Method D3588-91 for calorific value; or

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

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

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

(4) Test results shall be reported in the units of the applicable emission limits and averaging periods. If compliance testing is based on 40 CFR Part 60, Appendix A reference methods, the report must contain the information specified in §117.211(g) of this title (relating to Initial Demonstration of Compliance).

(5) For boilers, process heaters, or engines equipped with CEMS or PEMS, the CEMS or PEMS shall be installed and operational before testing under this subsection. Verification of operational status shall, as a minimum, include completion of the initial monitor certification and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(6) Initial compliance with the emission specifications of §117.475 of this title for boilers, process heaters, or engines operating with CEMS or PEMS shall be demonstrated after monitor certification testing using the NO_x CEMS or PEMS.

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

(A) Retesting as specified in paragraphs (1) - (4) of this subsection is required within 60 days after any modification which could reasonably be expected to increase the NO_x emission rate.

(B) Retesting as specified in paragraphs (1) - (4) of this subsection may be conducted at the discretion of the owner or operator after any modification which could reasonably be expected to decrease the NO_x emission rate, including, but not limited to, installation of post-combustion controls, low-NO_x burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation (FGR), and fuel-lean and conventional (fuel-rich) reburn.

(C) The NO_x emission rate determined by the retesting shall establish a new emission factor to be used to calculate actual emissions instead of the previously determined emission factor used to calculate actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program).

(8) Testing shall be performed in accordance with the schedule specified in §117.534 of this title.

(f) Emission allowances.

(1) For sources which are subject to Chapter 101, Subchapter H, Division 3 of this title, the NO_x testing and monitoring data of subsections (a) - (e) of this section, together with the level of activity, as defined in §101.350 of this title (relating to Definitions), shall be used to establish the emission factor calculating actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(2) The emission factor in subsection (e)(7) of this section or paragraph (1) of this subsection is multiplied by the unit's level of activity to determine the unit's actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(g) Recordkeeping. The owner or operator of a unit subject to the emission limitations of §117.475 of this title 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) records of annual fuel usage;

(2) for each unit using a CEMS or PEMS in accordance with subsection (c) of this section, monitoring records of:

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

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

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

(ii) pounds or tons per day;

(3) for each stationary internal combustion engine subject to the emission limitations of §117.475 of this title, records of:

(A) emissions measurements required by §117.478(b)(5) of this title (relating to Operating Requirements); and

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

(4) records of carbon monoxide measurements specified in §117.478(b)(5) of this title;

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

(6) records of the results of performance testing, including the testing conducted in accordance with subsection (e) of this section.

(h) Records for exempt engines. Written records of the number of hours of operation for each day's operation shall be made for each engine exempted based on run time under §117.473(a)(2)(H) of this title (relating to Exemptions) or §117.478(b)(5) of this title. The records shall be maintained for at least two years and shall be made available upon request to representatives of the executive director, EPA, or any local air pollution control agency having jurisdiction.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009087
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

SUBCHAPTER E. ADMINISTRATIVE PROVISIONS

30 TAC §§117.510, 117.520, 117.534

STATUTORY AUTHORITY

The amendments and new section 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; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air, such as the SIP; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the TCAA; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Board; Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382.

§117.510. Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas.

(a) The owner or operator of each electric utility in the Beaumont/Port Arthur ozone nonattainment area shall comply with the requirements of Subchapter B, Division 1 of this chapter (relating to Utility Electric Generation in Ozone Nonattainment Areas) as soon as practicable, but no later than the dates specified in this subsection.

(1) Reasonably Available Control Technology (RACT). The owner or operator shall for all units, comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than November 15, 1999 (final compliance date), except as specified in subparagraph (D) of this paragraph, relating to oil firing, and paragraph (2) of this subsection, relating to emission specifications for attainment demonstration.

(A) Conduct applicable continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) evaluations and quality assurance procedures as specified in §117.113 of this title (relating to Continuous Demonstration of Compliance) according to the following schedules:

(i) for equipment and software required pursuant to 40 Code of Federal Regulations (CFR) 75, no later than January 1, 1995 for units firing coal, and no later than July 1, 1995 for units firing natural gas or oil; and

(ii) for equipment and software not required under 40 CFR 75, no later than November 15, 1999;

(B) Install all nitrogen oxides (NO_x) abatement equipment and implement all NO_x control techniques no later than November 15, 1999;

(C) Submit to the executive director:

(i) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.111 of this title (relating to Initial Demonstration of Compliance); by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(ii) for units operating with CEMS or PEMS in accordance with §117.113 of this title, the results of:

(I) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.113 of this title; and

(II) the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title;

(III) no later than:

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

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

(D) Conduct applicable tests for initial demonstration of compliance with the NO_x emission limit for fuel oil firing, in accordance with §117.111(d)(2) of this title, and submit test results within 60 days after completion of such testing; and

(E) Submit a final control plan for compliance in accordance with §117.115 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology), no later than November 15, 1999.

(2) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.106(a) of this title (relating to Emission Specifications for Attainment Demonstrations) as soon as practicable, but no later than:

(A) May 1, 2003, demonstrate that at least two-thirds of the NO_x emission reductions required by §117.106(a) of this title have been accomplished, as measured either by

(i) the total number of units required to reduce emissions in order to comply with §117.106(a) of this title using direct compliance with the emission specifications, counting only units still required to reduce after May 11, 2000; or

(ii) the total amount of emissions reductions required to comply with §117.106(a) of this title using the alternative methods to comply, either:

(I) Section 117.108 of this title (relating to System Cap); or

(II) Section 117.570 of this title (relating to Trading);

(B) May 1, 2003, submit to the executive director:

(i) identification of enforceable emission limits which satisfy subparagraph (A) of this paragraph;

(ii) the information specified in §117.116 of this title (relating to Final Control Plans Procedures for Attainment Demonstration Emission Specifications) to comply with subparagraph (A) of this paragraph; and

(iii) any other revisions to the source's final control plan as a result of complying with subparagraph (A) of this paragraph;

(C) July 31, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap to comply with subparagraph (A) of this paragraph;

(D) May 1, 2005, comply with §117.106(a) of this title;

(E) May 1, 2005, submit a revised final control plan which contains:

(i) a demonstration of compliance with §117.106(a) of this title;

(ii) the information specified in §117.116 of this title; and

(iii) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.106(a) of this title; and

(F) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap NO_x emission limit to comply with the emission specifications in §117.106(a) of this title.

(b) The owner or operator of each electric utility in the Dallas/Fort Worth ozone nonattainment area shall comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than the dates specified in this subsection.

(1) Reasonably available control technology (RACT). The owner or operator shall comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than March 31, 2001 (final compliance date), except as provided in subparagraph (D) of this paragraph, relating to oil firing, and paragraph (2) of this subsection, relating to emission specifications for attainment demonstration.

(A) Conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.113 of this title no later than March 31, 2001;

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

(C) Submit to the executive director:

(i) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.111 of this title no later than March 31, 2001;

(ii) for units operating with CEMS or PEMS in accordance with §117.113 of this title, the results of:

(I) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.113 of this title; and

(II) the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title;

(III) no later than:

(-a-) March 31, 2001 for units complying with the NO_x emission limit in pounds per hour on a block one-hour average;

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

(D) Conduct applicable tests for initial demonstration of compliance with the NO_x emission limit for fuel oil firing, in accordance with §117.111(d)(2) of this title, and submit test results within 60 days after completion of such testing; and

(E) Submit a final control plan for compliance in accordance with §117.115 of this title, no later than March 31, 2001.

(2) Emission specifications for attainment demonstration.

(A) The owner or operator shall comply with the requirements of §117.106(b) of this title as soon as practicable, but no later than:

(i) May 1, 2003, demonstrate that at least two-thirds of the NO_x emission reductions required by §117.106(b) of this title have been accomplished, as measured either by

(I) the total number of units required to reduce emissions in order to comply with §117.106(b) of this title using direct compliance with the emission specifications, counting only units still required to reduce after May 11, 2000; or

(II) the total amount of emissions reductions required to comply with §117.106(b) of this title using the alternative methods to comply, either:

(-a-) Section 117.108 of this title (relating to System Cap); or

(-b-) Section 117.570 (relating to Trading);

(ii) May 1, 2003, submit to the executive director:

(I) identification of enforceable emission limits which satisfy clause (i) of this subparagraph;

(II) the information specified in §117.116 of this title to comply with clause (i) of this subparagraph; and

(III) any other revisions to the source's final control plan as a result of complying with clause (i) of this subparagraph;

(iii) July 31, 2003, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap to comply with clause (i) of this subparagraph;

(iv) May 1, 2005, comply with §117.106(b) of this title;

(v) May 1, 2005, submit a revised final control plan which contains:

(I) a demonstration of compliance with §117.106(b) of this title;

(II) the information specified in §117.116 of this title; and

(III) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.106(b) of this title; and

(vi) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title, if using the 30-day average system cap NO_x emission limit to comply with the emission specifications in §117.106(b) of this title.

(B) The requirements of §117.510(b)(2)(A)(i) of this title may be modified as follows. Boilers which are to be retired and decommissioned before May 1, 2005 are not required to install controls by May 1, 2003 if the following conditions are met:

(i) the boiler is designated by the Public Utility Commission of Texas to be necessary to operate for reliability of the electric system;

(ii) the owner provides the executive director an enforceable written commitment by May 1, 2003 to retire and permanently decommission the boiler by May 1, 2005;

(iii) the utility boiler is retired and permanently decommissioned by May 1, 2005; and

(iv) by May 1, 2003, all remaining boilers (those not designated for retirement and decommissioning as specified in clauses (i) - (iii) of this subparagraph) within the electric utility system are controlled to achieve at least two-thirds of the NO_x emission reductions from units not being retired and decommissioned.

(c) The owner or operator of each electric utility in the Houston/Galveston ozone nonattainment area shall comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than the dates specified in this subsection.

(1) Reasonably Available Control Technology. The owner or operator shall, for all units, comply with the requirements of Subchapter B, Division 1 of this chapter as soon as practicable, but no later than November 15, 1999 (final compliance date), except as specified in subparagraph (D) of this paragraph, relating to oil firing, and paragraph (2) of this subsection, relating to emission specifications for attainment demonstration.

(A) conduct applicable CEMS or PEMS evaluations and quality assurance procedures as specified in §117.113 of this title according to the following schedules:

(i) for equipment and software required pursuant to 40 CFR 75, no later than January 1, 1995 for units firing coal, and no later than July 1, 1995 for units firing natural gas or oil; and

(ii) for equipment and software not required under 40 CFR 75, no later than November 15, 1999;

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

(C) submit to the executive director:

(i) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.111 of this title; by April 1, 1994, or as early as practicable, but in no case later than November 15, 1999;

(ii) for units operating with CEMS or PEMS in accordance with §117.113 of this title, the results of:

(I) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.113 of this title; and

(II) the applicable tests for the initial demonstration of compliance as specified in §117.111 of this title;

(III) no later than:

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

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

(D) conduct applicable tests for initial demonstration of compliance with the NO_x emission limit for fuel oil firing, in accordance with §117.111(d)(2) of this title, and submit test results within 60 days after completion of such testing; and

(E) submit a final control plan for compliance in accordance with §117.115 of this title, no later than November 15, 1999.

(2) Emission specifications for attainment demonstration.

(A) The owner or operator shall comply with the requirements of §117.114 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) of this title as soon as practicable, but no later than:

(i) the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date), install any totalizing fuel flow meters, and emissions monitors required by §117.114 of this title; and

(ii) 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(I) stack tests conducted pursuant to §117.111 of this title; or, as applicable,

(II) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.113 of this title;

(B) The owner or operator shall comply with the requirements of §117.108 of this title as soon as practicable, but no later than:

(i) March 31, 2003, demonstrate that at least 46% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.108 of this title;

(ii) March 31, 2004, demonstrate that at least 92% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.108 of this title; and

(iii) March 31, 2007, demonstrate compliance with the system cap limit of §117.108 of this title; and

(C) For any unit subject to §117.106(c) of this title for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph (2)(A)(ii) of this subsection, the owner or operator shall submit to the executive director as soon as practicable, but no later than March 31, 2007, the results of

(i) stack tests conducted pursuant to §117.111 of this title; or, as applicable,

(ii) the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.113 of this title.

§117.520. Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas.

(a) The owner or operator of each industrial, commercial, and institutional source in the Beaumont/Port Arthur ozone nonattainment area shall comply with the requirements of Subchapter B, Division 3 of this chapter (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas) as soon as practicable, but no later than the dates specified in this subsection.

(1) Reasonably available control technology (RACT). The owner or operator shall for all units, comply with the requirements of Subchapter B, Division 3 of this chapter, except as specified in paragraph (2) (relating to lean-burn engines) and paragraph (3) of this subsection (relating to emission specifications for attainment demonstration) of this subsection, by November 15, 1999 (final compliance date) and submit to the executive director:

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

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

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

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

(iii) no later than:

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

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

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

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

(2) Lean-burn engines. The owner or operator shall for each lean-burn, stationary, reciprocating internal combustion engine subject to §117.205(e) of this title (relating to Emission Specifications), comply with the requirements of Subchapter B, Division 3 of this chapter for those engines as soon as practicable, but no later than November 15, 2001 (final compliance date for lean-burn engines); and

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

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

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

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

(3) Emission specifications for attainment demonstration. The owner or operator shall comply with the requirements of §117.206(a) of this title (relating to Emission Specifications for Attainment Demonstrations) as soon as practicable, but no later than

(A) May 1, 2003, demonstrate that at least two-thirds of the NO_x emission reductions required by §117.206(a) of this title have been accomplished, as measured either by

(i) the total number of units required to reduce emissions in order to comply with §117.206(a) of this title using direct compliance with the emission specifications, counting only units still required to reduce after May 11, 2000; or

(ii) the total amount of emissions reductions required to comply with §117.206(a) of this title using the alternative methods to comply, either:

(I) §117.207 of this title (relating to Alternative Plant-Wide Emission Specifications);

(II) §117.223 of this title (relating to Source Cap), or

(III) §117.570 of this title (relating to Trading);

(B) May 1, 2003, submit to the executive director:

(i) identification of enforceable emission limits which satisfy the conditions of subparagraph (A) of this paragraph;

(ii) for units operating without CEMS or PEMS or for units operating with CEMS or PEMS and complying with the NO_x emission limit on an hourly average, the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title;

(iii) for units newly operating with CEMS or PEMS to comply with the monitoring requirements of §117.213(c)(1)(C) of this title or §117.223 of this title, the applicable CEMS or PEMS performance evaluation and quality assurance procedures as specified in §117.213(e)(1)(A) and (B) and (f)(3) - (5)(A) of this title;

(iv) the information specified in §117.216 of this title (relating to Final Control Plans Procedures for Attainment Demonstration Emission Specifications); and

(v) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.206(a) of this title;

(C) July 31, 2003, submit to the executive director:

(i) the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title, for units complying with the NO_x emission limit on a rolling 30-day average; and

(ii) the first semiannual report required by §117.213(c)(1)(C), §117.219(e), and §117.223(e) of this title, covering the period May 1, 2003 through June 30, 2003;

(D) May 1, 2005, comply with §117.206(a) of this title;

(E) May 1, 2005, submit a revised final control plan which contains:

(i) a demonstration of compliance with §117.206(a) of this title;

(ii) the information specified in §117.216 of this title; and

(iii) any other revisions to the source's final control plan as a result of complying with the emission specifications in §117.206(a) of this title; and

(F) July 31, 2005, submit to the executive director the applicable tests for the initial demonstration of compliance as specified in §117.211 of this title, if using the 30-day average source cap NO_x emission limit to comply with the emission specifications in §117.206(a) of this title.

(b) The owner or operator of each industrial, commercial, and institutional source in the Dallas/Fort Worth ozone nonattainment area shall comply with the requirements of Subchapter B, Division 3 of this chapter as soon as practicable, but no later than March 31, 2002 (final compliance date). The owner or operator shall:

(1) install all NO_x abatement equipment and implement all NO_x control techniques no later than March 31, 2002; and

(2) submit to the executive director:

(A) for units operating without CEMS or PEMS, the results of applicable tests for initial demonstration of compliance as specified in §117.211 of this title as early as practicable, but in no case later than March 31, 2002;

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

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

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

(iii) no later than:

(I) March 31, 2002, for units complying with the NO_x emission limit on an hourly average; and

(II) May 31, 2002, for units complying with the NO_x emission limit on a rolling 30-day average;

(C) a final control plan for compliance in accordance with §117.215 of this title, no later than March 31, 2002; and

(D) the first semiannual report required by §117.219(d) or (e) of this title, covering the period March 31, 2002 through June 30, 2002, no later than July 31, 2002.

(c) The owner or operator of each industrial, commercial, and institutional source in the Houston/Galveston ozone nonattainment area shall comply with the requirements of Subchapter B, Division 3 of this chapter as soon as practicable, but no later than the dates specified in this subsection.

(1) Reasonably available control technology (RACT). The owner or operator shall, for all units, comply with the requirements of Subchapter B, Division 3 of this chapter, except as specified in paragraph (2) (relating to emission specifications for attainment demonstration), by November 15, 1999 (final compliance date) and:

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

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

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

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

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

(C) submit to the executive director:

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

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

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

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

(III) no later than:

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

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

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

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

(2) Emission specifications for attainment demonstration.

(A) The owner or operator shall comply with the requirements of §117.214 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration) as soon as practicable, but no later than:

(i) the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date), install any totalizing fuel flow meters, and emissions monitors required by §117.114 of this title; and

(ii) 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(I) stack tests conducted pursuant to §117.211 of this title; or, as applicable,

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

(B) The owner of operator of each electric generating facility (EGF) shall:

(i) no later than June 30, 2001, submit to the executive director the certification of level of activity, H_i, specified in §117.210 of this title (relating to System Cap) for EGFs which were in operation as of January 1, 1997;

(ii) no later than 60 days after the second consecutive third quarter of actual level of activity level data are available, submit to the executive director the certification of activity level, H_i, specified in §117.210 of this title for EGFs which were not in operation prior to January 1, 1997; and

(iii) comply with the requirements of §117.210 of this title as soon as practicable, but no later than:

(I) March 31, 2004, demonstrate that at least 44% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.210 of this title;

(II) March 31, 2005, demonstrate that at least 89% of the NO_x emission reductions have been accomplished, as measured by the difference between the highest 30-day average emissions measured in the 1997 - 1999 period and the system cap limit of §117.210 of this title; and

(III) March 31, 2007, demonstrate compliance with the system cap of §117.210 of this title;

(C) For any units subject to §117.206(c) of this title for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph (2)(A) of this subsection, the owner or operator shall submit to the executive director as soon as practicable, but no later than March 31, 2007, the results of:

(i) stack tests conducted pursuant to §117.211 of this title; or, as applicable,

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

(D) For non-EGFs, the owner or operator shall comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) as soon as practicable, but no later than the appropriate dates specified in that program.

§117.534. Compliance Schedule for Boilers, Process Heaters, and Stationary Engines at Minor Sources.

The owner or operator of each stationary source of nitrogen oxides (NO_x) in the Houston/Galveston ozone nonattainment area which is not a major source of NO_x shall comply with the requirements of Subchapter D, Division 2 of this chapter (relating to Boilers, Process Heaters, and Stationary Engines at Minor Sources) as follows.

(1) For sources which are subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), the owner or operator shall:

(A) install any totalizing fuel flow meters required by §117.479 of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements) and begin keeping records of fuel usage at the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date);

(B) no later than 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(i) stack tests conducted pursuant to §117.479 of this title; or, as applicable,

(ii) the applicable continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) performance evaluation and quality assurance procedures as specified in §117.213(e)(1)(A) and (B) and (f)(3) - (5)(A) of this title (relating to Continuous Demonstration of Compliance);

(C) no later than March 31, 2005, for any units subject to §117.475 of this title (relating to Emission Specifications) for which stack testing or CEMS/PEMS performance evaluation and quality assurance has not been conducted under paragraph (1)(B) of this section, submit to the executive director the results of:

(i) stack tests conducted pursuant to §117.479 of this title; or, as applicable,

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

(D) comply with the emission reduction requirements of Chapter 101, Subchapter H, Division 3 of this title as soon as practicable, but no later than the appropriate dates specified in that program.

(2) For sources which are not subject to Chapter 101, Subchapter H, Division 3 of this title, the owner or operator shall:

(A) install any totalizing fuel flow meters required by §117.479 of this title and begin keeping records of fuel usage at the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date);

(B) no later than 60 days after startup of a unit following installation of emissions controls, submit to the executive director the results of:

(i) stack tests conducted pursuant to §117.479 of this title; or, as applicable,

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

(C) comply with all other requirements of Subchapter D, Division 2 of this chapter as soon as practicable, but no later than March 31, 2005.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009088
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-0348

♦ ♦ ♦

30 TAC §117.570

The Texas Natural Resource Conservation Commission (commission) adopts the amendment to §117.570, Trading, *without changes* to the proposed text as published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8318) and therefore will not be republished. This amendment will be submitted as a revision to the Texas state implementation plan (SIP).

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULE

In concurrent rulemaking, §101.29 is repealed and its requirements transferred and amended to new Chapter 101, Subchapter H, Divisions 1 and 4. This rulemaking amends §117.570 to cite the correct cross-references and relocate equations and methodologies for calculating emission requirements to comply with Chapter 117 nitrogen oxides (NO_x) emission specifications to Chapter 101, Subchapter H, Divisions 1 and 4. In addition, the amended section requires the user of credits to obtain additional emission credits or achieve lower actual emissions if new lower NO_x emission specifications are established by future amendments to Chapter 117.

SECTION BY SECTION DISCUSSION

Revised §117.570 changes the title of the section to "Use of Emissions Credits for Compliance" from "Trading" to more clearly reflect the language in §117.570, which discusses how to use emission reduction credits for alternative compliance, not how to trade emission reduction credits.

The amendment to §117.570(a) removes the reference to §101.29 and replaces it with a reference to Chapter 101, Subchapter H, Division 1, Emission Reduction Credit Banking and Trading, or Chapter 101, Subchapter H, Division 4, Discrete Emission Reduction Banking and Trading. In addition, this adoption clarifies that emission reduction credits (ERCs), mobile emission reduction credits (MERCs), discrete emission reduction credits (DERCs), or mobile discrete emission reduction credits (MDERCs) may be used to meet certain control requirements of Chapter 117. This option would be limited to those units not subject to the mass cap and trade requirements of Chapter 101, Subchapter H, Division 3. The term "RC" refers to an ERC, MERC, DERC, or MDERC.

Existing §117.570(b) and the equations located within, is deleted because the methodology for computing emission credits for compliance with Chapter 117 is revised to be consistent with concurrently adopted methodology in Chapter 101, Subchapter H, new Divisions 1 and 4.

Section 117.570(c) and the equations located within, are deleted. The equations in §117.570(c)(1) are transferred to Chapter 101, Subchapter H, new Divisions 1 and 4 in concurrent rulemaking. The equations in §117.570(c)(2) are deleted because the methodology for computing emission credits for compliance with Chapter 117 is revised to be consistent with concurrently adopted methodology in Chapter 101, Subchapter H, new Divisions 1 and 4.

The revisions to §117.570(d) redesignate the subsection to §117.570(b) and remove the requirement to reevaluate used RCs. The revisions also add language detailing how owners or operators using Chapter 101, Subchapter H, Division 1 or Division 4 to meet the emission control requirements of Chapter 117 must obtain additional RCs or reduce actual emissions if any lower volatile organic compound emission specification is established by Chapter 117 for the unit or units using RCs.

FINAL REGULATORY IMPACT ANALYSIS

The commission has reviewed the adopted rulemaking in light of the regulatory analysis requirements of Texas Government

Code, §2001.0225. The commission has determined that this amendment to Chapter 117 does not meet the definition of a "major environmental rule" as defined in Texas Government Code, §2001.0225. "Major environmental rule" means a rule, the specific intent of which, is to protect the environment or reduce risks to human health from environmental exposure, and that may adversely affect in a material way the economy, 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 commission is adopting this amendment to achieve administrative consistency with amendments to Chapter 101 adopted in concurrent rulemaking. The amendment to Chapter 117 does not add regulatory requirements, but is adopted to allow compliance flexibility in meeting current or future NO_x emission limitations in Chapter 117. Therefore, there will be no adverse impact of this rule.

TAKINGS IMPACT ASSESSMENT

The commission has completed a takings impact assessment for the adopted rule. The following is a summary of that assessment. The commission is adopting the amendment to achieve administrative consistency with amendments to Chapter 101 adopted in concurrent rulemaking. The amendment to Chapter 117 does not add regulatory requirements, but allows compliance flexibility in meeting current or future NO_x emission limitations in Chapter 117. The amendment does not affect private real property in a manner which restricts or limits an owner's right to the property that would otherwise exist in the absence of a governmental action. Consequently, the adopted section does not meet the definition of a takings under Texas Government Code, §2007.002(5).

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission has determined the 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 the Texas Coastal Management Program. As required by 30 TAC §281.45(a)(3) and 31 TAC §505.11(b)(2), 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, and has determined that the rule is 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. The amendment to Chapter 117 does not add regulatory requirements, but is adopted to allow compliance flexibility in meeting current or future NO_x emission limitations in Chapter 117.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMITS PROGRAM

Sources which currently have §117.570 listed in their federal operating permit would not be required to amend the permit in response to this amendment. However, those sources that do not have a reference to §117.570 in their operating permit and wish to use RCs must revise their operating permit consistent with the process in 30 TAC Chapter 122, to include the revised §117.570 requirements for each emission unit affected by §117.570 at their site.

PUBLIC HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: September 18, 2000, in Conroe and Lake Jackson; September 19, 2000 in Houston (two hearings); September 20, 2000, in Katy and Pasadena; September 21, 2000, in Beaumont, Amarillo, and Texas City; September 22, 2000, in Dayton, El Paso, and Arlington; and September 25, 2000, in Austin and Corpus Christi. The comment period closed at 5:00 p.m. on September 25, 2000.

The EPA opposed the amendment to §117.570.

ANALYSIS OF TESTIMONY

The EPA questioned whether the definitions of "baseline activity" and "baseline emissions" are redundant. If the only reason for defining baseline emissions is to provide emission reduction trading for non mass cap and trade reasonably available control technology (RACT) sources, then §117.570 should be revised so that RACT source cannot participate in a discretionary trading program without an activity limit on the source.

The rule was not revised in response to this comment. The purpose of §117.570 is to allow the option to facilities subject to Chapter 117 to obtain and use emission credits in lieu of making actual emission reductions in all areas of the state. It should be noted that this trading does not apply to facilities subject to the Houston/Galveston nonattainment area NO_x cap and trade program. The purpose of "baseline activity" and "baseline emission rate" is to multiply the two together to determine the baseline emissions of a facility. They are therefore not redundant. This determination is not only necessary for the determination of how many credits can be generated from a facility, but also for determinating the amount of credits to be used for compliance by a facility. In addition, facilities not subject to the HGA cap and trade program do not have their emission capped at baseline levels; thus capping their level of activity for compliance with Chapter 117 is not appropriate. Besides which, the specific requirement in the cap and trade program, Chapter 117 does not regulate total emissions, only the rate of emissions.

STATUTORY AUTHORITY

The amendment is adopted under the Texas Health and Safety Code, TCAA, §382.011, which authorizes the commission to control the quality of the state's air; §382.012, which authorizes the commission to develop a plan for control of the state's air; §382.017, which provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA, and 42 United States Code, §7410(a)(2)(A), which requires SIPs to include enforceable emission limitations and other control measures or techniques, including economic incentives such as fees, marketable permits, and auction of emission rights.

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

Filed with the Office of the Secretary of State on December 29, 2000.

TRD-200009076

Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 18, 2001
Proposal publication date: August 25, 2000
For further information, please call: (512) 239-6087

♦ ♦ ♦

TITLE 31. NATURAL RESOURCES AND CONSERVATION

PART 20. EDWARDS AQUIFER AUTHORITY

CHAPTER 711. GROUNDWATER WITHDRAWAL PERMITS

SUBCHAPTER C. EXEMPT WELLS

31 TAC §§711.18, 711.20, 711.22, 711.24, 711.26, 711.28, 711.30, 711.32, 711.34, 711.36, 711.38, 711.40, 711.42, 711.44, 711.46, 711.48

The Edwards Aquifer Authority (the "Authority") adopts new 31 TAC §§711.18, 711.20, 711.22, 711.24, 711.26, 711.28, 711.30, 711.32, 711.34, 711.36, 711.38, 711.40, 711.42, 711.44, 711.46, and 711.48 to be codified at Title 31, TEXAS ADMINISTRATIVE CODE Chapter 711, Subchapter C (the "Chapter 711 Subchapter C rules"), relating to the Authority's implementation of an exempt well program, which is a corollary to the Authority's groundwater withdrawal permitting program. Sections 711.18, 711.22, 711.32, 711.34, 711.46, and 711.48 are adopted with changes to the proposed text as published in the September 29, 2000 issue of the *Texas Register* (25 TexReg 9868) and are republished herein. Sections 711.20, 711.24, 711.26, 711.28, 711.30, 711.36, 711.38, 711.40, 711.42, and 711.44 are adopted without changes and will not be republished.

The Edwards Aquifer Authority Act, Act of May 30, 1993, 73rd Legislature Regular Session, Chapter 626, 1993 TEXAS GENERAL LAWS 2350, as amended by Act of May 28, 1995, 74th Legislature Regular Session, Chapter 3189, 1995 TEXAS GENERAL LAWS 2505, Act of May 16, 1995, 74th Legislature Regular Session, Chapter 361, 1995 TEXAS GENERAL LAWS 3280, and Act of May 6, 1999, 76th Legislature Regular Session, Chapter 163, 1999 TEXAS GENERAL LAWS 634 (the "Act"), requires the Authority to implement a permitting system whereby "existing users" of groundwater from the Edwards Aquifer and other potential users of aquifer water may apply for and receive initial regular permits or other types of permits issued by the Authority allowing for the withdrawal of groundwater from the aquifer. Such withdrawals must be metered. Certain withdrawals, on the other hand, are exempted by the Act from permitting and metering requirements. The Act specifies certain criteria in order to qualify for such "exempt well" status and imposes certain requirements upon exempt wells. The Act requires the Authority to manage and regulate all withdrawal points (i.e. wells) from the Edwards Aquifer, and therefore, the Authority is required to regulate exempt wells even though they are otherwise exempt from permitting and metering requirements. The Chapter 711 Subchapter C rules are intended to effectuate the components of the Act which exempt certain wells from the permitting and metering requirements and impose requirements on such wells.

The Chapter 711 Subchapter C rules are adopted pursuant to the following statutory provisions contained within the Act and other relevant statutory provisions.

Section 1.03(9) of the Act defines "domestic or livestock use." This is the only type of use, as mandated by §1.33 of the Act, for which withdrawals from exempt well may be used.

Section 1.03(11) of the Act defines "industrial use." Section 1.03(12) of the Act defines "irrigation use." These types of uses are not authorized from exempt wells.

Section 1.03(13) of the Act defines "livestock." The Chapter 711 Subchapter C rules incorporate this concept when determining whether a well qualifies as "exempt" from permitting requirements.

Section 1.03(14) of the Act defines "municipal use." The Chapter 711 Subchapter C rules incorporate this concept within the types of uses for which aquifer water may be withdrawn.

Section 1.08(a) of the Act provides that the Authority "has all of the powers, rights, and privileges necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer." This section provides the Authority with broad and general powers to take actions as necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer. These powers are exercised in the adoption of the Subchapter C rules.

Section 1.11(a) of the Act provides that the Board of Directors ("Board") of the Authority "shall adopt rules necessary to carry out the authority's powers and duties under (Article 1 of the Act), including rule governing procedures of the board and the authority." This section provides broad rulemaking authority to implement the various substantive and procedures programs set forth in the Act related to the Edwards Aquifer, including the exempt well program.

Section 1.11(b) of the Act requires the Authority to "ensure compliance with permitting, metering, and reporting requirements and . . . regulate permits." This section, in conjunction with §1.11(a) and (h) of the Act, and §2001.004(1) of the APA, requires the Authority to adopt and enforce the Chapter 711 rules.

Section 1.11(h) of the Act provides, among other things, that the Authority is "subject to" the APA. This section essentially provides that the Authority is required to comply with the APA for its rulemaking, even though the Authority is a political subdivision and not a state agency that would generally be subject to APA requirements.

Section 1.14(b) of the Act imposes, subject to certain limitations, an initial aquifer withdrawal "cap" for permitted withdrawals of 450,000 acre-feet per year, until December 31, 2007. The Chapter 711 Subchapter C rules explain that this cap does not apply to exempt wells.

Section 1.14(c) of the Act imposes, subject to certain limitations, an aquifer withdrawal "cap" for permitted withdrawals of 400,000 acre-feet per year, beginning January 1, 2008. The Chapter 711 Subchapter C rules explain that this cap does not apply to exempt wells.

Section 1.15(a) of the Act directs the Authority to manage all withdrawals from the aquifer and manage all withdrawal points from the aquifer as provided by the Act. This section is implemented in part through the Chapter 711 Subchapter C rules.

Section 1.15(b) of the Act states that "except as provided by §§1.17 and 1.33 of this article, a person may not withdraw water from the aquifer or begin construction of a well or other works designed for the withdrawal of water from the aquifer without obtaining a permit from the authority." This section is implemented in part through the Chapter 711 Subchapter C rules.

Section 1.16(c) of the Act provides that an owner of a well from which the water will be used exclusively for domestic use or watering livestock and that is exempt under §1.33 of the Act is not required to file a declaration of historical use. This concept is incorporated into the Subchapter C rules from Chapter 711.

Section 1.17(a) of the Act provides that a person who, on the effective date of this article, owns a producing well that withdraws water from the aquifer may continue to withdraw and beneficially use water without waste until final action on permits by the Authority, if: (1) the well is in compliance with all statutes and rules relating to well construction, approval, location, spacing, and operation; and (2) by March 1, 1994, the person files a declaration of historical use on a form as required by the Authority. This concept is incorporated into the Chapter 711 rules.

Section 1.17(b) of the Act specifies that use under "interim authorization" may not exceed on an annual basis the historical, maximum, beneficial use of water without waste during any one calendar year as evidenced by the person's declaration of historical use. This concept is incorporated into the Chapter 711 rules.

Section 1.17(c) of the Act specifies that use under "interim authorization" is subject to the Authority's comprehensive management plan and rules. This concept is incorporated into the Chapter 711 rules.

Section 1.17(d) of the Act specifies when use under "interim authorization" ends for a given well. This concept is incorporated into the Chapter 711 rules.

Section 1.29 of the Act outlines the Authority's ability to assess various types of fees to users of the aquifer and others. Certain provisions within this section are relevant to the determination of whether exempt well owners must pay such fees.

Section 1.33 of the Act provides the criteria for exempt wells -- i.e., wells that produce no more than 25,000 gallons of water per day for domestic and livestock use and that are not within or serving a subdivision requiring platting. The section explains that such wells are exempt from metering requirements. However, such wells must be registered with the Authority. These concepts are implemented in Chapter 711, primarily in Subchapter C.

Chapter 36 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 36.101(a) empowers the Authority to make and enforce rules to provide for conserving, preserving, protecting, and recharging of the groundwater in order to, among other things, prevent waste and carry out the duties provided elsewhere in Chapter 36. This requirement is implemented, in large part, through the Chapter 711 rules.

Chapter 36 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 36.117 allows districts such as the Authority to exempt certain wells from permitting requirements based on criteria similar to §1.33 of the Act.

Chapter 36 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 36.119(a) decrees that drilling a well without a required permit or operating a well at a higher rate of production than the rate approved for the well is declared to be illegal, wasteful per se, and a nuisance. This concept is incorporated into the Chapter 711 rules.

Chapter 49 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 49.211(a) endows districts such as the Authority with the "functions, powers, authority, rights, and duties that will permit accomplishment of the purposes for which it was created or the purposes authorized by the constitution, this code, or any other law." This broad delegation of powers is incorporated into the Chapter 711 rules.

The Act specifies that certain wells are exempt from metering and permitting requirements unless they are within or serving a subdivision required to be platted. Thus, it is necessary in Subchapter C of the Chapter 711 rules to apply platting and subdivision concepts found in Chapter 212 and 232 of the Texas Local Government Code. Section 212.004 defines when a municipality may require a subdivision of land to be platted. Section 212.0046 provides municipalities an exception from the platting requirements for certain land abutting an aircraft runway. Section 212.013 provides a mechanism for the vacating of a plat. Section 232.001 defines when a county may require a subdivision of land to be platted. Section 232.0015 provides counties numerous exceptions from the platting requirement. Section 232.008 provides a mechanism for the cancellation of a subdivision. The concepts in these sections are incorporated into the Subchapter C rules.

The Subchapter C Rules

Sections 711.18-711.48, the Chapter 711 Subchapter C rules, set forth the criteria under which a well qualifies as being exempt from the Authority's permitting requirements, the effect of qualifying as an exempt well, and the requirements applicable to exempt wells.

Section 711.18 sets forth the definitions that will apply to all rules within Subchapter C of Chapter 711. These rules have been written to provide uniform definitions for words and phrases that are expected to be used consistently in relation to exempt wells. They are intended to provide useful "short-hand" to reduce the amount of cumbersome regulatory language necessary in other Authority rules, thus allowing for a more efficient understanding and operation of other rules of the Authority.

Pursuant to §1.33 of the Act, the determination of whether or not a well qualifies as exempt turns in part upon whether or not the well is "within or serving a subdivision requiring platting." The Act provides no guidance in its text as to what "within or serving a subdivision requiring platting" means. A substantial body of law exists, however, in other contexts which relates to the requirement to plat certain subdivisions of land. Chapters 212 and 232 of the Texas Local Government Code contain extensive laws relating to when a municipality or county, respectively, may require a subdivision of land to be platted. The Authority is not charged, generally, with zoning, development and related land use planning responsibilities. Further, the Authority is not directed by the Act, nor does the Authority intend, to actually require the platting of subdivisions. Instead, these responsibilities lie with cities and counties. Thus, instead of attempting to create its own rules relating to platting, the Authority has determined that it is reasonable to simply incorporate and adopt, with some minor adjustments necessary and appropriate for the Authority's exempt well program, the platting requirements applicable to cities and counties.

The definitions in §711.18 have been designed to implement and clarify the legal concepts which are found in chapters 212 and

232 of the Texas Local Government Code regarding when a subdivision of land must be platted. The law governing the platting of subdivisions, as contained in Chapter 212 and 232, is at times confusing. Further, the power of municipalities to require platting differs from the power counties have to require platting. The Authority's rules are intended, for the most part, to track these differences.

In §711.18 as originally proposed, the Authority included definitions of "dedication," "public use," and "use of purchasers or owners." Each of those words or phrases is used in §§212.004 and 232.001 of the Texas Local Government Code. The Authority has determined, however, that it is not necessary to separately define each of these words or phrases. Instead, the Authority believes it would be more prudent to simply use those words and phrases in a manner consistent with their usage in §§212.004 and 232.001 of the Texas Local Government Code. Thus, the Authority has withdrawn each of these definitions from consideration for adoption at this time. This deletion has necessitated the renumbering of the remaining definitions found within §711.18.

Sections 212.004 and 232.001 of the Texas Local Government Code generally impose platting requirements when land is "divided" or a "division" of land occurs. These sections then go on to explain what constitutes a "division." Thus, §711.18 includes a definition of "divide or division" which tracks the statutory language found in the Texas Local Government Code. The wording of the definition, as adopted, has been slightly revised from the wording as proposed in order to more closely track §§212.004 and 232.001.

Sections 212.004 and 232.001 of the Texas Local Government Code describe the required contents of a "plat." The Authority believes it is beneficial to include within §711.18 a definition of "plat" which clarifies the term which is used throughout the Subchapter C rules. The source of this definition is *Elgin Bank v. Travis County*, 906 S.W.2d 120, 121 n. 1 (Tex. App. - Austin 1995, writ denied).

Section 711.18 includes a definition of the phrase "subdivision of land" which tracks the usage of that phrase in §§212.004(a) and 232.001(a) of the Texas Local Government Code

Section 711.18 includes a definition of the phrase "tract of land." It is the act of dividing a tract of land which triggers the possibility that a plat may be required. The Authority believes it is appropriate and helpful to include a definition which clarifies that the size of the land is immaterial to whether it will be considered a "tract of land."

Section 711.20 sets forth the criteria under which a well qualifies for exempt well status. Such a well must: (1) be incapable of producing more than 25,000 gallons per day; (2) be used solely for domestic or livestock use; and (3) not be within or serving a subdivision requiring platting. These requirements derive directly from §1.33 of the Act. The Authority believes that, in order to be eligible to be an exempt well, a well must, among other things, be "used solely for domestic or livestock use." Under §1.33 of the Act, a well that produces 25,000 gallons of water per day or less for domestic or livestock use is generally exempt from the permitting requirement. All other types of withdrawals must be permitted pursuant to §1.15(b) of the Act. Further, §1.16(c) provides that the owner of a well used "exclusively" for domestic and livestock use is not required to apply for a permit. Thus, the Authority believes it lacks the discretion to allow withdrawals for non-exempt uses from an exempt well.

Similarly, the Authority has determined that a well must be physically incapable of producing more than 25,000 gallons per day in order to be considered exempt. Section 1.33(a) of the Act states that, in order to be exempt, the well must produce "25,000 gallons of water a day or less." Section 1.33(a) then exempts such wells from the metering requirement. If exempt wells are exempt from having meters installed on them, then the Authority has no reliable method to accurately and independently determine the quantity of water pumped from the well (i.e. to confirm whether the well actually complies with the 25,000 gallon per day requirement). In the absence of such an ability, the Authority must simply require that the wells be incapable of producing more than that amount. Such a requirement ensures that the dictates of §1.33(a) of the Act are met. Further, the administrative convenience of the Authority is enhanced by requiring that exempt wells be physically incapable of producing more than 25,000 gallons. In the absence of such a rule, the Authority would apparently bear the Herculean task of constantly inspecting each exempt well to ensure that it is not used to pump more than 25,000 gallons on any given day.

Section 711.22 sets forth the effect of qualifying for exempt well status by explaining which portions of the Act and the Authority's rules apply and do not apply to owners of exempt wells. Subsection (a) provides that all provisions of the Act and the Authority's rules apply to owners of exempt wells, except for those exclusions provided for in subsection (b). Pursuant to subsection (b)(1), owners of exempt wells are exempted from the Authority's metering rules which will be found in subchapter M of Chapter 711. This is consistent with §1.33(a) of the Act which exempts exempt wells "from metering requirements."

Pursuant to subsection (b)(2), owners of exempt wells are exempted from the requirement found in the Authority's rule 711.12(a)(1) to obtain a permit before withdrawing Edwards Aquifer water. This is consistent with §1.15(b) of the Act, which provides that all a person may not withdraw water from the aquifer without obtaining a permit unless that person's well is exempt. As originally proposed, subsection (b)(2) also exempted exempt well owners from §711.12(a)(3), (5), (6) and (7). The Authority has deleted these exemptions from the rule as adopted because the exemptions were erroneous, nonsensical, and inadvertently included in the rule as proposed. Section 711.12(a)(3) requires a permit for the construction of a monitoring well. Section 711.12(5) requires a permit for wells withdrawing water from an aquifer other than the Edwards but which intersect the Edwards Aquifer. Section 711.12(6) requires a permit to recharge water into the aquifer. Section 711.12(7) requires a permit to store water in the aquifer. Each of these activities is unrelated to the operation of an exempt well.

Pursuant to §711.22(b)(3), owners of exempt wells are exempted from the requirement found in the Authority's rule 711.311 to file a declaration of historical use. This is consistent with §1.16(c) which excludes exempt well owners from having to file such a declaration.

Pursuant to §711.22(b)(4), owners of exempt wells are exempted from subchapters D and E of the Authority's Chapter 709 aquifer management fee rules. The Authority has determined that it is administratively unfeasible to assess aquifer management fees or permit retirement special fees against exempt wells. Sections 1.29(b) and (e) of the Act empower the Authority to assess aquifer management fees. Under §1.29(e), those fees must be based on either the "volume of water withdrawn" or the "amount of water a permit holder is authorized to withdraw under the permit." Owners of exempt wells hold no permit and, therefore, have no authorized withdrawal amount specified in a permit. Further, exempt wells are, pursuant to §1.33 of the Act, unmetered. Thus, it is impossible to accurately determine the volume of water actually withdrawn and assess fees on that amount. Similarly, pursuant to §1.29(c), permit retirement special fees must be "based on permitted aquifer water rights." Because exempt wells do not operate under a permit, they have no permitted rights upon which to base a fee.

Section 711.22(b)(4), as originally proposed, also exempted exempt well owners from the requirement to pay the $25 fee for an application to construct an exempt well found in Subchapter C of the Authority's Chapter 709 rules. The Authority has deleted this provision in the rule as adopted because it is inconsistent with the intent of the Authority and with other rules adopted by the Authority. It is the Authority's intent that any person wishing to construct a new exempt well must first obtain a well construction permit from the Authority. This is made clear in §711.22(b)(2) which *does not* excuse an exempt well owner from the construction permit requirement found in §711.12(a)(2). It is also the intent of the Authority that the permit fee be paid before any such construction permit may be issued. This intent is clear in Subchapter C of the Chapter 709 rules which were recently adopted by the Authority as final rules.

Finally, §711.22(c) generally prohibits an owner of an exempt well from obtaining a groundwater withdrawal permit for the well or obtaining interim authorization status for the well. This is consistent with §711.46, which prohibits "dual status wells." Section 711.22(c) has been slightly revised to add the word "will" in order to correct a typographical error in the rule as proposed. The rule as adopted, showing the inserted language in italics, now reads as follows:

(c) Unless the well status is converted pursuant to §711.48 of this chapter (relating to Conversion of Well Status), the owner of an exempt well may not obtain a groundwater withdrawal permit for the well, nor *will* the well qualify for interim authorization status.

Section 711.24 explains that exempt well withdrawals are not to be counted against the 450,000 and 400,000 acre-feet withdrawal "caps" set forth in §1.14(b) and (c) of the Act. This is because §1.14(b) and (c) of the Act specifically state that the caps apply to "permitted withdrawals." By definition, exempt wells are exempt from permitting requirements and are, therefore, not permitted withdrawals.

Section 711.26 dictates that owners of exempt wells must register those wells with the Authority. This is consistent with §1.33(b) of the Act which provides that exempt wells must be registered.

Section 711.28 requires that any person proposing to construct an exempt well after the effective date of the Chapter 711 Subchapter C rules must first obtain from the Authority a well construction permit (pursuant to Authority rule 707.305) and a determination that the well qualifies for exempt status (pursuant to Authority rule 707.308). Section 1.15(a) and (b) of the Act require the Authority to manage and regulate all withdrawal points from the aquifer, and to require permits for the construction of aquifer wells. The Authority cannot manage and regulate wells if it does not know of their existence. Further, it must have a mechanism in place to confirm whether any given new well meets the exempt well criteria. This rule furthers these objectives and requirements.

Section 711.30 provides that aquifer water withdrawn from an exempt well may be beneficially used only for domestic or livestock use. The Authority believes that, in order to be eligible to be an exempt well, a well must, among other things, be used *solely* for domestic or livestock use. Under §1.33 of the Act, a well that produces 25,000 gallons of water per day or less for domestic or livestock use is generally exempt from the permitting requirement. All other types of withdrawals must be permitted pursuant to §1.15(b) of the Act. Further, §1.16(c) provides than the owner of a well used "exclusively" for domestic and livestock use is not required to apply for a permit. Thus, the Authority believes it lacks the discretion to allow withdrawals for non-exempt uses from an exempt well.

Section 711.32 provides that exempt wells must be drilled, constructed or equipped so that they are incapable of producing more than 25,000 gallons per day. The Authority believes that a well must be physically incapable of producing more than 25,000 gallons per day in order to be considered exempt. Section 1.33(a) of the Act states that, in order to be exempt, the well must produce "25,000 gallons of water a day or less." Section 1.33(a) then exempts such wells from the metering requirement. If exempt wells are exempt from having meters installed on them, then the Authority has no reliable method to accurately and independently determine the quantity of water pumped from the well (i.e. to confirm whether the well actually complies with the 25,000 gallon per day requirement). In the absence of such an ability, the Authority must simply require that the wells be incapable of producing more than that amount. Such a requirement ensures that the dictates of §1.33(a) of the Act are met. Further, the administrative convenience of the Authority is enhanced by requiring that exempt wells be physically incapable of producing more than 25,000 gallons. In the absence of such a rule, the Authority would apparently bear the Herculean task of constantly inspecting each exempt well to ensure that it is not used to pump more than 25,000 gallons on any given day. As explained more fully in response to public comments, below, the text of §711.32 has been modified slightly.

Section 711.34 sets out the criteria for determining whether a subdivision of land is required to be platted. Under the terms of the Act, the determination of whether or not a well qualifies as exempt turns in part upon whether or not the well is "within or serving a subdivision requiring platting." The Authority must determine whether platting is required in order to determine whether a given well is eligible to be considered an exempt well. By adopting the rule, the Authority will not itself "require platting of subdivisions in the Edwards Aquifer region." Instead, the rule simply adopts, with certain qualifications discussed more fully above, the criteria set forth in Chapters 212 and 232 in order to determine whether a given well is within or serving a subdivision requiring platting. If it is not, then the well may be exempt if it meets the other criteria. If it is, then the well cannot be exempt.

The Authority believes that a standardized definition of when a subdivision is classified as requiring platting, which is based upon existing principles found in the Texas Local Government Code, should be applied throughout the Edwards Aquifer region. As stated above, the Authority's rules closely track Chapters 212 (relating to platting requirements by municipalities) and 232 (relating to platting requirements by counties) of the Texas Local Government Code. Those chapters set out the general standards and exemptions from the platting requirement which apply statewide. It is those general standards and exemptions which the Authority has incorporated into its exempt well rules.

The Authority acknowledges that Chapters 212 and 232 also include provisions which give municipalities and counties the discretion to deviate from those statewide platting requirements on a case-by-case basis. See TEXAS LOCAL GOVERNMENT CODE, §§212.0045(a) and 232.0015(a). The Authority's rules do not incorporate this concept. In practice, the discretion given to counties and cities in determining platting requirements can lead to wide deviations regarding whether a particular subdivision of land is considered to require platting. For example, a subdivision of land in San Antonio might be required by the City to be platted, while a subdivision of land under identical circumstances in Hondo might not be required by that City to be platted. Similarly, a subdivision of land in Hays County might be required to be platted while a subdivision of land under identical circumstances in Bexar County might not be required to be platted. Because the Local Government Code allows each city and county the discretion to deviate from the statewide standards, there is very little predictability as to whether any given subdivision is required to be platted.

The Authority believes it is preferable and necessary to adopt the statewide standards in order to have a cogent and consistent exempt well program. The Authority cannot fairly and consistently implement its exempt well program if the "subdivision requiring platting" requirement varies from city to city and county to county within its jurisdiction. It is unfair and unreasonable, for example, to grant a well owner in Comal County exempt well status simply because that well owner lives in a county which might decide to deviate from the statewide standards, while denying exempt well status to a well owner in Uvalde County whose land was subdivided under identical circumstances and whose county decided not to deviate from the statewide standards. Further, such a scheme would be administratively unworkable from the Authority's standpoint. Authority staff cannot and should not be expected to be intimately knowledgeable about the minutia of the platting rules of each city and county within its jurisdiction. For these reasons, the Authority believes it is prudent, reasonable, and consistent with the legislative intent behind §1.33 of the Act that the exempt well rules utilize the standard statewide criteria found in the Texas Local Government Code in determining whether a subdivision is classified as requiring platting.

Consistent with the definitions found in §711.18 and consistent with the approach taken in Chapters 212 and 232, §711.34 generally dictates that, unless a specific, listed exemption applies, a subdivision of land is classified as requiring platting. As explained in response to public comments, the wording of this section has been modified slightly to clarify that the Authority is merely determining whether a subdivision of land is classified as requiring platting; it is not actually requiring platting.

The section then goes on to list a number of exemptions to the platting requirement. The exemptions set forth in subsection (b)(1) through (b)(10) all derive directly from §232.0015(c), (e), (f), (g), (h), (i), (j), (k) and §§212.004, 212.0046 of the Texas Local Government Code and require no further elaboration.

The exemption in section 711.34(b)(11) is the only one which is not derived from the Texas Local Government Code. As originally proposed, it provided that a subdivision of land will be considered exempt from the platting requirement if: (A) the subdivision occurred prior to June 28, 1996; and (B) at the time when a decision is made on whether the well in question is eligible for exempt well status, the subdivision within which the well is located does not have retail service and is not scheduled to receive retail water service within one year from the date on which the application for exempt well status was filed.

Upon reconsideration, the Authority has decided to modify this rule so that it now provides that a subdivision of land will be considered exempt from the platting requirement if: (A) the subdivision occurred *prior to the effective date of the Chapter 711 subchapter C rules*; and (B) at the time when a decision is made on whether the well in question is eligible for exempt well status, the subdivision within which the well is located does not have retail service and is not scheduled to receive retail water service within one year from the date on which the application for exempt well status was filed. The (b)(11) exemption, as originally proposed, applied only to subdivisions platted prior to the effective date of the Act. The Authority determined that, for the purposes of this exemption, there was no reason to treat subdivisions that were platted following the effective date of the Act but prior to the effective date of these rules different from subdivisions that were platted prior to the effective date of the Act.

In establishing this exemption, the Authority has looked to the purposes of section 1.33 of the Act, which states that "a well within or serving a subdivision requiring platting does not qualify for an exempt use." The Authority believes that the purpose of this condition is essentially three-fold. First, it is meant to encourage owners of lots in the Edwards Aquifer regions who are domestic water users to connect to regional water suppliers or to an organized purveyor of water service. Second, it is meant to discourage the creation and propagation of *colonias*, or subdivisions with substandard or non-existent water and other infrastructure and services. Third, it is meant to mitigate against the proliferation and drilling of a large number wells serving single residences into the Edwards Aquifer, possibly creating hundreds or thousands of additional wells that are not permitted and which would be managed under a much lower and more lenient set of regulations.

Under (b)(11)(A), the (b)(11) exemption applies only to wells in areas that were subdivided prior to the effective date of the this subchapter. The EAA has established this exemption because of the almost complete impracticability of requiring a well owner seeking exempt well status, or Authority staff in verifying and determining such a claim, to effectively research and determine the status of past platting requirements in specific locations. Also, the EAA declines to seek to apply the EAA platting criteria set forth in paragraphs (b)(1) through (10), to subdivisions that were platted prior to the effective date of these rules.

Moreover, the Authority believes that the additional condition for this exemption set forth in (b)(11)(B) serves the functional equivalent of actually determining whether the subdivision required platting under local law at the relevant time and, in doing so, serves the purposes of §1.33 of the Act noted above. That condition - that the subdivision in which the well is located does not have retail water service and is not scheduled to receive retail water service within one year - serves to advance the interests of §1.33 of the Act noted above, without imposing the impractical and untenable requirement that a well owner (and Authority staff) determine the exact nature of past platting requirements in the location that the well and the subdivision in question are located.

In addition, the wording of the (b)(11) exemption has been revised slightly in order to clarify it and make clear that the well must satisfy both conditions of (B) - (i) and (ii) - rather than meeting only one of the two conditions.

Section 711.36 explains that a well is within a subdivision requiring platting if it is located within a tract of land that is required to be platted pursuant to §711.34. This rule merely carries out the requirements of §1.33(c) of the Act.

Section 711.38 explains the criteria under which a well will be considered to serve a subdivision requiring platting. This rule merely carries out the requirements of §1.33(c) of the Act, which states that a well "within or serving a subdivision requiring platting does not qualify for an exempt use." The Act does not define the phrase "serving a subdivision requiring platting." Thus, this rule attempts to give meaning to this phrase. It loosely follows language found in §36.117 of the Texas Water Code, which also relates to the criteria for exempt wells under that chapter.

Section 711.40 explains the criteria under which an exempt well in existence on the effective date of these rules can retain its exempt status if it is subsequently encompassed within a subdivision requiring platting. Such a well must not serve the subdivision requiring platting and must otherwise continue to meet the exempt well criteria. However, such a well may not retain its exempt status if it was drilled within one year prior to the platting of the subdivision of land, or if it is a well from which no withdrawals have been made prior to the time the subdivision is platted. These provisions are intended to prevent wells owners from avoiding the Act's permitting requirements by drilling exempt wells in anticipation of a subsequent subdivision requiring platting, and to prevent the needless designation of an exempt well for a well which has never actually been used.

Section 711.42 provides that a well located within or serving a subdivision requiring platting (and is therefore non-exempt) may subsequently qualify as exempt if the subdivision requiring platting is lawfully vacated or canceled. Section 232.008 of the Texas Local Government Code allows for the cancellation of a subdivision. If a subdivision is cancelled, then it is possible that a well within the former subdivision would no longer be considered to be "within or serving a subdivision requiring platting." In such a case, it could then potentially qualify as an exempt well pursuant to the criteria set forth in §1.33 of the Act. This rule is intended to account for such a possibility.

Section 711.44 provides the criteria under which an exempt well may lose its exempt status and requires the owner of such a well to provide notice to the Authority within 30 days of any occurrence causing the well to lose its exempt status. Exempt well status will be lost if: (1) withdrawals from the well are used for non-exempt purposes; (2) the well is modified so that it is capable of producing more than 25,000 gallons of water per day; or (3) the well subsequently begins to serve a subdivision requiring platting. The bases for these criteria are explained above.

Section 711.46 provides that a well may be either an exempt well or a well for which a permit is required, but not both simultaneously. In other words, so-called "dual status wells" are prohibited. As explained above, the Authority has concluded that exempt wells must be used exclusively for withdrawals for exempt purposes. Therefore, exempt wells and permitted wells constitute two, mutually exclusive classes of wells. As originally proposed, the title of §711.46 was "Dual Status Wells." Given the substance of the rule, the Authority believes the title should be revised to clarify its intent. Accordingly, the title of the rule as adopted is "Dual Status Wells Prohibited." Further, as originally proposed, the section had an initial subsection and then subsections (a) and (b). The Authority believes it would be preferable to reorganize the section by designating the initial subsection as (a) and re-lettering the subsequent subsections as (b) and (c). The rule, as adopted, incorporates these changes. Subsection (b) of §711.46 provides that if the irrigation and exempt withdrawals are separately metered, then withdrawals for an exempt use may be made from a non-exempt (i.e. permitted) irrigation well. The text of this section has been slightly revised to reference the Authority's applicable metering rule which explains how the separate meters should be installed. The rationale for this subsection of the rule is that many irrigators use de minimis amounts of water from their permitted irrigation wells for exempt well uses, such as for the filling of livestock watering troughs. Finally, subsection (c) provides that withdrawals for uses requiring a permit may not be made from an exempt well. The rationale for this provision is that, as explained above, the Authority has concluded that exempt wells must be used exclusively for exempt purposes.

Section 711.48 provides that the owner of a well for which a permit is required may apply to the Authority to convert it to an exempt well if the well otherwise meets the exempt well criteria. Likewise, the owner of an exempt well may apply to the Authority to convert it to a non-exempt well if the owner obtains the transfer of interim authorization or permit rights which would justify operation of the well on a permitted basis. The wording of the rule has been modified slightly to clarify that if an exempt well is converted to a permitted well, all withdrawals for exempt purposes must cease from that well, except as otherwise provided by §711.46. The Authority believes there is no reason why the status of a well could not change so long as the criteria for either exempt or permitted status can be complied with.

Section 2001.0225 of the Texas Government Code requires an agency to perform, under certain circumstances, a regulatory analysis of major environmental rules ("RIAMER"). There are two primary components that must be met before a RIAMER is required. First, no RIAMER need be prepared if the rules in question are not "major environmental rules" or "MERs." Second, even if the rules are MERs, no RIAMER need be prepared if adoption of the MERs would not result in any one of the following criteria listed in §2001.0225(a)(1)-(4):

1. the MER would "exceed" a standard set by federal law, unless the MER is specifically required by state law;

2. the MER would "exceed" an express requirement of state law, unless the MER is specifically required by federal law;

3. the MER would "exceed" a requirement of a delegation agreement or contract between the state and an agency or representative of the federal governmental to implement a state and federal program; or

4. the MER is adopted solely under the "general powers" of the agency instead of under a specific state law.

The Chapter 711 Subchapter C rules essentially set forth: the criteria under which a well would qualify as being exempt from the Authority's permitting requirements, the effect of qualifying as an exempt well, and the requirements applicable to exempt wells. The Subchapter C rules limit the legal authority to withdraw groundwater from the aquifer based on quantity of withdrawals, well location, and purpose of use of the well. This limitation did not exist under the common law. These withdrawal limitations would tend to have an environmental protection aspect. Therefore, the Subchapter C rules probably have, among other things, the specific intent to "protect the environment" and might qualify as MERs.

However, without determining whether the Subchapter C rules are MERs, the Authority has concluded that no RIAMER need be prepared for any of the Subchapter C rules because none of the rules meet any of the criteria listed in APA §2001.0225(a)(1)-(4). First, the rules do not exceed a standard set by federal law. The only reasonably related federal law establishes the Sole Source Aquifer Program implemented by the EPA for portions of the Edwards Aquifer, which applies only to federally-funded projects conducted on the aquifer. There is no federal law that specifically requires permitting for withdrawals of Edwards Aquifer groundwater or exemptions from such permitting requirements. Therefore, the Subchapter C rules do not exceed a standard set by federal law. Moreover, even if the rules did exceed a standard set by federal law, the rules are specifically required by state law which requires the Authority to manage withdrawals from the aquifer, adopt rules to carry out its powers and duties under the Act, manage withdrawals and points of withdrawals from the aquifer and require permits for certain withdrawals while exempting other withdrawals from permitting requirements (pursuant to, *inter alia*, §§1.03(9), (11), (12), (13) and (14), 1.08(a), 1.11(a), (b) and (h), 1.14(b) and (c), 1.15(a) and (b), 1.16(c), 1.17, and 1.33(a) and (c) of the Act.

Second, the Subchapter C rules do not exceed an express requirement of state law. Instead, the rules are designed to carry out the Authority's statutory responsibility to manage withdrawals from the aquifer, adopt rules to carry out its powers and duties under the Act, manage withdrawals and points of withdrawals from the aquifer and require permits for certain withdrawals while exempting other withdrawals from permitting requirements (pursuant to, *inter alia*, §§1.03(9), (11), (12), (13) and (14), 1.08(a), 1.11(a), (b) and (h), 1.14(b) and (c), 1.15(a) and (b), 1.16(c), 1.17, and 1.33(a) and (c) of the Act). The rules are designed to comply with these express requirements of state law and not exceed them.

Further, §1.33(c) of the Act provides that the determination of whether or not a well qualifies as exempt turns in part upon whether the well is "within or serving a subdivision requiring platting." The Authority has not attempted to "reinvent" the principles governing when a subdivision of land must be platted. Instead, the Subchapter C rules track the platting and subdivision rules applicable to municipalities and counties found within Chapters 212 and 232 of the Texas Local Government Code. There are no other applicable "express requirements of state law" which are applicable to these rules or which could be exceeded by these rules.

Third, the Subchapter C rules do not exceed a requirement of a delegation agreement or contract between the State of Texas and an agency or representative of the federal government to implement a state and federal program. The subject matter of the rules is not covered by any delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program.

Fourth, the Subchapter C rules would not be adopted solely under the general powers of the Authority instead of under a specific state law. While these rules are adopted in part under the Authority's general powers, they are also adopted under the Act, a specific state law regarding the Edwards Aquifer. In particular, the rules are adopted pursuant to, *inter alia*, §§1.03(9), (11), (12), (13) and (14), 1.08(a), 1.11(a), (b) and (h), 1.14(b) and (c), 1.15(a) and (b), 1.16(c), 1.17, and 1.33(a) and (c) of the Act which require the Authority to manage withdrawals from the aquifer, adopt rules to carry out its powers and duties under the Act, manage withdrawals and points of withdrawals from the aquifer and require permits for certain withdrawals while exempting other withdrawals from permitting requirements.

For these reasons, it is not necessary to perform a RIAMER on the Subchapter C rules.

The Authority has received public comments to the above-referenced proposed rules and has prepared responses thereto as set forth below:

Five public hearings were held on the Chapter 711 Subchapter C rules and other rules proposed by the Authority on: Monday, October 2, 2000 at 6:00 p.m. at the conference center of the Edwards Aquifer Authority, 1615 N. St. Mary's Street, San Antonio, Texas; Tuesday, October 3, 2000 at 6:00 p.m., at St. Paul's Lutheran Church, 1303 Avenue M, Hondo, Texas; Wednesday, October 4, 2000 at 6:00 p.m., at the San Marcos Activity Center, 501 E. Hopkins, San Marcos, Texas; Wednesday, October 11, 2000 at 6:00 p.m., at the Sgt. Willie DeLeon Civic Center, 300 E. Main Street, Uvalde, Texas; and Thursday, October 12, 2000, at 6:00 p.m., at the New Braunfels Civic Center, 380 S. Seguin Avenue, New Braunfels, Texas.

The public comment period closed on October 30, 2000. Oral and/or written comments were provided by Bickerstaff, Heath, Smiley, Pollan, Kever & McDaniel, L.L.P. on behalf of the Texas Farm Bureau ("TFB"), San Antonio Water System ("SAWS"), Andrew J. Aelvoet on behalf of Southwest Texas Federal Land Bank Association ("Federal Land Bank"), Robert Grossenbacher ("Grossenbacher"), Raymond Bartran ("Bartran"), and Liza Toombs ("Toombs").

While the commenters generally did not express support or opposition to adoption of the Subchapter C Rules as a whole, they did, as discussed more fully below, suggest changes to and/or opposition to certain portions of the rules. Section 711.20 Public Comment:

Federal Land Bank believes §711.20(2) is "impractical" and requests a revision that provides for incidental withdrawals of aquifer water related to domestic and livestock use. Federal Land Bank contends that domestic use of Edwards Aquifer water in rural areas would necessarily include uses incidental to home ownership such as watering of yards and providing water for swimming pools.

Authority Response:

The Authority disagrees with the comment and declines to revise §711.20(2). That section merely provides that, in order to be eligible to be an exempt well, a well must, among other things, be "used solely for domestic or livestock use." The text of the rule closely follows the sections of the Act related to exempt wells. Under §1.33 of the Act, a well that produces 25,000 gallons of water per day or less for domestic or livestock use is generally exempt from the permitting requirement. All other types of withdrawals must be permitted pursuant to §1.15(b). Further, §1.16(c) provides that the owner of a well used "exclusively" for domestic and livestock use is not required to apply for a permit. Thus, in these sections the Legislature has limited the withdrawals for non-exempt uses from an exempt well for these exempt purposes.

Public Comment:

Federal Land Bank asserts that proposed rule §711.20(3) does not conform to §1.33 (c) of the EAA Act. The Federal Land Bank asserts that the rule should be revised, as indicated in italics, in order to "conform with the intent of the Texas Legislature:"

(3) it is not within or serving a subdivision requiring platting *by the county or municipality in which the subdivision is situated*.

Authority Response:

The Authority disagrees with the comment and declines to revise the rule in response thereto. The language in §711.20(3) - "within or serving a subdivision requiring platting" -- derives word-for-word from §1.33(c) of the Act. The additional language sought by the Federal Land Bank is not found in the Act.

Section 1.33 of the Act clearly mandates that a well which is "within or serving a subdivision requiring platting" cannot qualify as exempt. It is therefore unavoidable that the Authority must devise a mechanism by which to determine whether a given well is within or serving a subdivision requiring platting. The Authority has chosen to do so not by creating its own, entirely new platting regimen, but by generally adopting the platting requirements set forth in Chapters 212 and 232 of the Texas Local Government Code. The Authority believes a standardized definition of when a subdivision is classified as requiring platting, which is based upon existing principles found in the Texas Local Government Code, should be applied throughout the Edwards Aquifer region. The Authority's rules closely track Chapters 212 (relating to platting requirements by municipalities) and 232 (relating to platting requirements by counties) of the Texas Local Government Code. Those chapters set out general standards and exemptions from the platting requirement which apply statewide. It is those general standards and exemptions which the Authority has incorporated into its exempt well rules.

The Authority acknowledges that Chapters 212 and 232 also include provisions which give municipalities and counties the discretion to deviate from those statewide platting requirements on a case-by-case basis. See TEXAS LOCAL GOVERNMENT CODE, §§212.0045(a) and 232.0015(a). The Authority's rules do not incorporate this concept. In practice, the discretion given to counties and cities in determining platting requirements can lead to wide deviations regarding whether a particular subdivision of land is considered to require platting by a given county or municipality. For example, a subdivision of land in San Antonio might be required by the City to be platted, while a subdivision of land under identical circumstances in Hondo might not be required by that City to be platted. Similarly, a subdivision of land in Hays County might be required to be platted while a subdivision of land under identical circumstances in Bexar County might not be required to be platted. Because the Local Government Code allows each city and county the discretion to deviate from the statewide standards, there is very little predictability, in the absence of the statewide standards, as to whether any given subdivision is required to be platted.

Past practice of the Authority shows that it is impracticable to rely on the local political subdivisions that have traditionally regulated the subdivision of land. In general, the Authority has received poor cooperation at the city and county levels. Many cities and counties have been hostile to or disagree with the Authority's groundwater resource management programs. As such, they would "push it back on" the Authority to make the decision. Other political subdivisions did not have the political will to taken on controversial matters. Other cities and counties did not have the necessary staffing to promptly or expertly assist the Authority in processing its exempt well status determinations. Finally, each political subdivision of appropriate jurisdiction would institute differing criteria for approval of subdivisions or would construe similar provisions differently. Thus, from the Authority's perspective, similarly situated developments would be treated differently, or dissimilar developments would be treated the same without any particular reasonable basis. Accordingly, the Authority proposes to eliminate these problems by administering its own subdivision approval program.

The Authority believes it is preferable and necessary to adopt the statewide standards in order to have a cogent and consistent exempt well program. The Authority cannot fairly and consistently implement its exempt well program if the "subdivision requiring platting" requirement varies from city to city and county to county within its jurisdiction. It is unfair and unreasonable, for example, to grant a well owner in Comal County exempt well status simply because that well owner is lucky enough to live in a county which might decide to deviate from the statewide standards, while denying exempt well status to a well owner in Uvalde County whose land was subdivided under identical circumstances but whose county decided not to deviate from the statewide standards. Further, such a scheme would be administratively unworkable from the Authority's standpoint. Authority staff cannot and should not be expected to be intimately knowledgeable about the minutia of the platting rules and case-by-case exceptions of each city and county within its jurisdiction. For these reasons, the Authority believes it is prudent, reasonable, and consistent with the legislative intent behind §1.33 of the Act that the exempt well rules utilize a standardized definition of when a subdivision is classified as requiring platting based upon existing principles found in the Texas Local Government Code, while not adopting those provisions which give municipalities and counties the discretion to deviate from those statewide platting requirements.

Section 711.22

Public Comment:

As proposed, §711.22(b) read, in pertinent part:

The owner of an exempt well is not required to comply with the requirements of:

. . . (4) subchapter C (relating to Permit Application Fees), D (relating to Aquifer Management Fees) of Chapter 709 (relating to Fees) or E (relating to Permit Retirement Special Fees of this title.

SAWS asserts that §711.22(b)(4) should be revised to clarify that new exempt wells are required to receive a well construction permit and pay the associated fee for the construction permit. SAWS also identifies a typographical error in the section. To correct these issues, SAWS suggests that §711.22(b)(4) be revised to read as follows:

The owner of an exempt well is not required to comply with the requirements of:

. . . (4) subchapters D (relating to Aquifer Management Fees) and E (relating to Permit Retirement Special Fees) of chapter 709 (relating to Fees).

Authority Response:

The Authority agrees with this comment and has revised §711.22(b)(4) accordingly. It is the Authority's intent that any person wishing to construct a new exempt well must first obtain a well construction permit from the Authority. This is made clear in §711.22(b)(2) which *does not* excuse an exempt well owner from the construction permit requirement found in §711.12(a)(2). It is also the intent of the Authority that the permit fee be paid before any such construction permit may be issued.

This intent is clear in Subchapter C of Chapter 709, rules which were recently adopted by the Authority as final rules.

Public Comment:

SAWS points out a typographical error in §711.22(c) and requests the insertion of the word "will" as italicized below:

(c). . .nor *will* the well qualify for interim authorization status.

Authority Response:

The Authority agrees with this comment and has revised the rule accordingly to correct the typographical error.

Section 711.32

Public Comments:

Section 711.32 provides, in part, that exempt wells must be "constructed and equipped" in such a way as to be incapable of producing in excess of 25,000 gallons per day. Federal Land Bank objects to this language and proposes changing §711.32 so that an exempt well need only be "equipped," not "constructed and equipped," to be incapable of producing more than 25,000 gallons per day. The bank reasons that some exempt wells were originally constructed for irrigation and were capable of pumping more than 25,000 gallons per day, but have been re-equipped for providing only for domestic and livestock uses. Such wells may be simply equipped in ways capable of producing no more than 25,000 gallons per day. The bank reasons that the rule should be revised in order to prevent the owner of such a well from having to drill a new well to meet his or her exempt well water needs. According to Federal Land Bank, a rule requiring only that exempt wells be equipped in such a way that prevents pumpage in excess of 25,000 a day is sufficient enough to safeguard against the threat of excessive withdrawals from exempt wells.

Grossenbacher objects to the requirement in the rule that an exempt well be incapable of producing more than 25,000 gallons per day. Grossenbacher reasons that while many smaller wells may be capable of producing over 25,000 gallons a day, the costs and mechanical difficulties of actually doing so may be too high to make it worthwhile. Therefore, Grossenbacher contends that it is unreasonable to require an exempt well owner to retrofit such a well in order to render it incapable of pumping more than 25,000 gallons per day.

Authority Response:

The Authority disagrees with the Grossenbacher comment and generally agrees with the Federal Land Bank comment. First, the Authority believes it is necessary that, in order to be considered exempt, a well must be physically incapable of producing more than 25,000 gallons per day. Section 1.33(a) of the Act states that, in order to be exempt, the well must produce "25,000 gallons of water a day or less." Section 1.33(a) then exempts such wells from the metering requirement. If exempt wells are exempt from having meters installed on them, then the Authority has no reliable method to accurately and independently determine the quantity of water pumped from the well (i.e. to confirm whether the well actually complies with the 25,000 gallon per day requirement). In the absence of such an ability, the Authority must simply require that the wells be incapable of producing more than that amount. Such a requirement ensures that the dictates of §1.33(a) of the Act are met. Further, the administrative convenience of the Authority is enhanced by requiring that exempt wells be physically incapable of producing more than 25,000 gallons. In the absence of such a rule, the Authority would apparently bear the Herculean task of constantly inspecting each exempt well to ensure that it is not used to pump more than 25,000 gallons on any given day.

Having concluded that wells must be physically incapable of producing more than 25,000 gallons per day, the Authority agrees with the suggestion of the Federal Land Bank that it should not matter whether the incapability derives from the original construction of the well or subsequent equipping of the well. Therefore, the Authority has revised the language of the rule to read as follows:

The owner of an exempt well may not produce more than 25,000 gallons of water a day. Such a well must also be either drilled, completed or equipped so that it is incapable of producing more than 25,000 gallons of water per day.

This language clarifies that the well's incapability to produce more than 25,000 gallons of water a day may derive from its construction, the method by which it is completed, or by how it is equipped. The language in this rule as revised derives from §36.117(a)(1) of the Texas Water Code, which incorporates similar concepts of exempt wells.

Section 711.34

Public Comments:

Federal Land Bank and Toombs assert that rule §711.34 allows the Authority to exceed its scope of power, as provided by the Act, by requiring the platting of subdivisions in the Edwards Aquifer region. Furthermore, it is suggested that the rule is an attempt to usurp power given to local county and municipal governments under chapters 212 and 232 of the Texas Local Government Code. Therefore, the deletion of this rule is urged. Federal Land Bank also objects to the Authority's use of a standardized definition of when platting is required throughout the Authority's boundaries.

Furthermore, Federal Land Bank believes §711.34(b)(4) is discriminatory in that it gives the Veteran's Land Board preference in financing options made available those purchasing subdivision lots.

Federal Land Bank also calls §711.34(b)(5) "discriminatory" because it requires no minimum lot size for a sub-divided tract of land owned by the State or agency or commission thereof although §711.34(b)(3) requires that a privately owned tract must be sub-divided into parcels greater than 10 acres in area.

Authority Response:

The Authority disagrees with these comments and declines to revise the Subchapter C rules in response thereto. As explained more fully above, §1.33 of the Act clearly mandates that a well which is "within or serving a subdivision requiring platting" cannot qualify as exempt. It is therefore unavoidable that the Authority must devise a mechanism by which to determine whether a given well is within or serving a subdivision requiring platting. The Authority has chosen to do so not by creating its own, entirely new platting regimen, but by generally adopting the platting requirements set forth in Chapters 212 and 232 of the Texas Local Government Code.

The comments appear to misunderstand the effect of §711.134. By adopting the rule, the Authority will not itself "require platting of subdivisions in the Edwards Aquifer region." Instead, the rule simply adopts, with certain qualifications discussed more fully above, the principles set forth in Chapters 212 and 232 in order to determine whether a given well is within or serving a subdivision requiring platting. If it is not, then the well may be exempt if it meets the other criteria. If it is, then the well cannot be exempt.

Further, the Authority believes that a standardized definition of when a subdivision is classified as requiring platting, which is based upon existing principles found in the Texas Local Government Code, should be applied throughout the Edwards Aquifer region. As stated above, the Authority's rules closely track Chapters 212 (relating to platting requirements by municipalities) and 232 (relating to platting requirements by counties) of the Texas Local Government Code. Those chapters set out general standards and exemptions from the platting requirement which apply statewide. It is those general standards and exemptions which the Authority has incorporated into its exempt well rules.

The Authority acknowledges that Chapters 212 and 232 also include provisions which give municipalities and counties the discretion to deviate from those statewide platting requirements on a case-by-case basis. See TEXAS LOCAL GOVERNMENT CODE, §§212.0045(a) and 232.0015(a). The Authority's rules do not incorporate this concept. In practice, the discretion given to counties and cities in determining platting requirements can lead to wide deviations regarding whether a particular subdivision of land is considered to require platting. For example, a subdivision of land in San Antonio might be required by the City to be platted, while a subdivision of land under identical circumstances in Hondo might not be required by that City to be platted. Similarly, a subdivision of land in Hays County might be required to be platted while a subdivision of land under identical circumstances in Bexar County might not be required to be platted. Because the Local Government Code allows each city and county the discretion to deviate from the statewide standards, there is very little predictability, in the absence of the statewide standards, as to whether any given subdivision is required to be platted.

The Authority believes it is preferable and necessary to adopt the statewide standards in order to have a cogent and consistent exempt well program. The Authority cannot fairly and consistently implement its exempt well program if the "subdivision requiring platting" requirement varies from city to city and county to county within its jurisdiction. It is unfair and unreasonable, for example, to grant a well owner in Comal County exempt well status simply because that well owner is lucky enough to live in a county which might decide to deviate from the statewide standards, while denying exempt well status to a well owner in Uvalde County whose land was subdivided under identical circumstances but whose county decided not to deviate from the statewide standards. Further, such a scheme would be administratively unworkable from the Authority's standpoint. Authority staff cannot and should not be expected to be intimately knowledgeable about the minutia of the platting rules of each city and county within its jurisdiction. For these reasons, the Authority believes it is prudent, reasonable, and consistent with the legislative intent behind §1.33 of the Act that the exempt well rules utilize a standardized definition of when a subdivision is classified as requiring platting based upon existing principles found in the Texas Local Government Code, while not adopting those provisions which give municipalities and counties the discretion to deviate from those statewide platting requirements.

The Authority believes that the comments on §711.34(b)(4) and (5) are also misplaced. Section 711.34(b)(4) provides that in certain instances when land is subdivided outside the limits and extraterritorial jurisdiction of a municipality and those lots are sold to veterans through the Veterans Land Board such a subdivision should be considered exempt from the platting requirements. This provision was not created by the Authority but by the Texas Legislature. The rule simply adopts what is already the law as found in §232.0015(g) of the Texas Local Government Code.

Similarly, the Authority acknowledges that §711.34(b)(5) does not impose a minimum lot size requirement while §711.34(b)(3) does impose a minimum lot size requirement. Both provisions set forth exemptions from the platting requirement. Both provisions, however, were created not by the Authority, but by the Texas Legislature. Section 711.34(b)(5) derives from §232.0015(h) and §711.34(3) derives from §232.0015(f) of the Texas Local Government Code.

Public Comment:

SAWS seeks revisions to §711.34(a) and (b) in order to clarify that the Authority does not have the ability to require the platting of property, but may only determine whether a subdivision required platting before granting exempt well status. SAWS seeks the following italicized changes:

(a) Except as provided in subsection (b) of this section, subdivisions of land required to be platted *per state law*.

(b) The following subdivisions of land are *not classified as requiring platting*:

Authority Response:

The Authority does not disagree with these comments. It has never been the Authority's intent to actually be the entity requiring platting. Instead, the Authority is merely required, pursuant to §1.33 of the Act, to determine whether a given well is within or serving a subdivision requiring platting in order to qualify for exempt well status. While the Authority declines to incorporate all of the specific changes sought by SAWS, the Authority does not object to revising the wording of §711.34(a) and (b) to make its intent more clear. Accordingly, those sections are revised in the rule as adopted to read as follows:

(a) Except as provided in subsection (b) of this section, subdivisions of land are classified as requiring platting.

(b) The following subdivisions of land are not classified as requiring platting:

Public Comment:

SAWS also seeks various grammatical, non-substantive revisions throughout §711.34.

Authority Response:

The Authority does not believe that these revisions substantially improve the rule as written and the Authority declines to adopt the suggested changes.

Public Comment:

Section 711.34(b)(1) provides the following exemption from the platting requirement:

(1) The owner of a tract of land located outside the limits and the extraterritorial jurisdiction of a municipality divides the tract into two or more parts, but:

. . . (B) the tract is to be used primarily for agricultural use, as defined in Section 1-d, Article VIII, Texas Constitution, ...

"Agricultural use" is defined in Section 1-d, Article VIII of the Texas Constitution as, "the raising of livestock or growing of crops, fruit, flowers, and other products of the soil under natural conditions as a business venture for profit, which business is the primary occupation and source of income of the owner."

In other rules adopted by the Authority, another definition of "agricultural use" is found. In §709.1(1), the Authority defines "agricultural use" as "the use of water for irrigation use."

TFB contends that the Authority should use the same definition of "agricultural use" throughout the rules and proposes using an alternate definition which is found in §2.001 of the Texas Agricultural Code. The TFB also contends that the definition in Article VIII, section 1-d of the Texas Constitution defines "agricultural use" for tax purposes only. Thus, the TFB contends that using this definition may place different subdivision requirements on land used for non-profit agricultural purposes.

Authority Response:

The Authority disagrees with this comment and declines to revise §711.34 in response thereto. The platting exemption found in §711.34(b)(1) is derived directly from §232.0015(c) of the Texas Local Government Code. As stated above, rather than "reinventing the wheel," the Authority has incorporated the standards set by state law regarding when a county may require platting of a subdivision. When it created that exemption, the Texas Legislature chose to utilize the definition of "agricultural use" found in Section 1-d, Article VIII of the Texas Constitution. The Authority declines to second-guess the Legislature by substituting an alternate definition. Any result which would place different subdivision requirements on land used for non-profit agricultural purposes as opposed to for-profit agricultural purposes must have been anticipated by the Texas Legislature when it adopted the exemption.

Further, the Authority does not believe that, as alleged by the TFB, the presence of a different definition of "agricultural use" found elsewhere in the Authority's rules will "cause confusion and . . . lead to inconsistent application of the rules." The two definitions serve entirely different and distinct purposes. The definition referred to in §711.34(b)(1) is clearly only relevant to the question of whether a given subdivision of land may be exempted from the platting requirement under that particular exemption. That definition is derived directly from state platting laws.

The definition of "agricultural use" found in the Authority's rule 709.1, on the other hand, is expressly made applicable only to the Authority's Chapter 709 rules. Rule 709.1 provides, in relevant part: "Definitions. The following words and terms, *when used in this chapter*, shall have the following meanings, unless the context clearly indicates otherwise:" (Emphasis added.) The Authority's Chapter 709 rules set forth the various types of fees imposed by the Authority and provide procedures for the adoption, assessment, billing and collection of fees from the regulated community. Section 1.29(e) of the Act provides that "the fee rate for agricultural use . . . may not be more than 20 percent of the fee rate for municipal use." Thus, the definition of "agricultural use" found within Chapter 709 is needed to identify who will be entitled to pay the lower fees.

The Authority declines to revise §711.34 in response to this comment.

Public Comment:

SAWS urges a revision to §711.34(b)(11) in order to create "consistency between EAA rules and state law concerning city services, such as water delivery." Specifically, SAWS points to §43.056 of the Local Government Code which provides deadlines and requirements that a municipality proposing annexation must meet. SAWS requests the following italicized change to §711.34(b)(11)(B)(ii):

Is not scheduled by a municipal distribution system to be provided retail water service *either by an annexation service plan* or within one year. . .

Authority Response:

The Authority disagrees with the comment and declines to revise §711.34 in response thereto. Section 711.34(b)(11) creates an exemption from the platting requirement for subdivisions of land which:

(A) occurred prior to June 28, 1996 (the effective date of the Act); and

(B) when final action is taken on an application for exempt well status:

(i) the subdivision does not have retail water service; and

(ii) the subdivision is not scheduled by a municipal distribution system to be provided retail water service within one year from the date the application for exempt well status was filed with the authority.

Pursuant to §43.056 of the Local Government Code, an annexation service plan must be prepared by a city proposing an annexation. The plan must set forth how the city will provide full services, including water service, to the annexed area within 2 1/2 years or, in some cases, 4 1/2 years after the effective date of the annexation. The Authority believes a 2 1/2 year or 4 1/2 year time frame is too remote for the purposes of the exemption found in §711.34(b)(11).

Section 711.44

Public Comment:

Federal Land Bank requests that proposed rule §711.44(a)(1) be revised so that the term "any withdrawal" is clarified. Furthermore, the commenter suggests "incidental and non-sustained withdrawals" from exempt wells, for purposes other than domestic and livestock use, should not justify a loss of exempt well status. Finally, Federal Land Bank requests a definition and quantification of amounts of withdrawals from the aquifer, for incidental and non-sustained use, that would not be prohibited from an exempt well.

Authority Response:

The Authority disagrees with the comment and declines to revise §711.44 in response thereto. Under §1.33 of the Act, a well that produces 25,000 gallons of water per day or less for domestic or livestock use is generally exempt from the permitting requirement. All other types of withdrawals must be permitted pursuant to §1.15(b). Further, §1.16(c) provides that the owner of a well used "exclusively" for domestic and livestock use is not required to apply for a permit. Thus, the Legislature has limited withdrawals for non-exempt uses from an exempt well for these exempt purposes.

Section 711.46

Public Comment:

Federal Land Bank believes this proposed rule (apparently subsection (b)) needs revisions and clarification due to its impracticability. The Bank argues that the rule should allow for incidental withdrawals of aquifer water for non-exempt uses from an exempt well.

Authority Response:

The Authority disagrees with the comment and declines to revise §711.44 in response thereto. Under §1.33 of the Act, a well that produces 25,000 gallons of water per day or less for domestic or livestock use is generally exempt from the permitting requirement. All other types of withdrawals must be permitted pursuant to §1.15(b). Further, §1.16(c) provides that the owner of a well used "exclusively" for domestic and livestock use is not required to apply for a permit. Thus, the Legislature has limited withdrawals for non-exempt uses from an exempt well for these exempt purposes.

Public Comment:

Section 711.46 provides that a well may either be an exempt well or a well for which a permit is required, but not both simultaneously. The rule goes on to provide, however, that, if separately metered, withdrawals for exempt use may be made from a non-exempt (i.e., permitted) irrigation well. Bartran asserts that allowing withdrawals for exempt uses from permitted wells conflicts with §711.402(e), a rule currently proposed for adoption by the Authority.

Authority Response:

The Authority agrees that §§711.46 and 711.402(e), when read together, could potentially be confusing. The Authority will revise the text of §711.402(e) in order to clarify and be consistent with §711.46. In addition, as discussed above, other revisions have been made to §711.46 to make it more readable and clear.

Comments on the Rules Generally

Public Comment:

The Texas Farm Bureau ("TFB") maintains that a takings impact statement ("TIA") was required before the Authority provided public notice of the proposed rules. According to TFB, the Texas Private Real Property Rights Preservation Act ("Property Rights Act") does not excuse the Authority from the requirements of the Property Right Act because the rights are not "vested" or because the Legislature has chosen to regulate those property rights. Furthermore, the TFB contends that property does not have to be vested to come within the purview of the Property Rights Act and, nonetheless, groundwater rights are vested rights requiring no perfection because they accompany the surface estate.

Authority Response:

The Authority has received this comment and disagrees with it. Chapter 2007 of the Texas Government Code, the Property Rights Act referred to by the TFB, requires governmental entities, under certain circumstances, to prepare a TIA in connection with certain covered categories of proposed governmental actions. Based on the following reasons, the Authority has determined that it need not prepare a TIA in connection with the adoption of these rules.

First, the Authority has made a "categorical determination" that these Chapter 711 Subchapter C rules do not affect vested property rights and, as such, adoption of these rules is not an action that "may result in a taking." The Act requires the Authority to implement a permitting system whereby existing users and other potential users of aquifer water may apply for and receive permits issued by the Authority allowing for the withdrawal of groundwater from the aquifer. Certain withdrawals are exempted by the Act from these permitting requirements. These rules are intended to effectuate the components of the Act which exempt certain wells from the permitting and metering requirements of the Act.

The Property Rights Act makes it clear that a TIA need only be performed when the proposed governmental action is one that "may result in a taking." *See id.*, §§2007.043(a), 2007.041(a), 2007.042(a). If an action is one that has no potential to result in a taking, then no TIA need be performed. Adoption of the rules at issue here is not an action that "may result in a taking" for several reasons.

The rules cannot result in the taking of a vested private real property right. Traditional takings doctrine dictates that, in order to constitute a compensable taking, the property right alleged to have been "taken" must rise to the level of a *vested* right. Prior to the adoption of the Act, a landowner's right to pump groundwater underlying his or her property derived from the common law English Rule, also known as the "Rule of Capture." The permitting requirement is admittedly at odds with the Rule of Capture. However, a landowner's common law Rule of Capture right does not rise to the level of a vested property right. Under the common law, water underlying a landowner's property may be reduced to possession by the pumping of another. In other words, a landowner has no right to exclude others from the water underlying his land. As such, the landowner's expectancy of water does not rise to the level of a vested property right which could be "taken" by implementation of a permitting program and the passage of these rules, and passage of these rules is not an action that may result in a taking. Further, the Subchapter C rules actually exempt certain wells from the permitting requirement, thereby excluding those wells from the permitting requirement in the first place.

Additionally, with respect to Edwards Aquifer water, any common law rights a landowner may have had in the past have been effectively abolished by the Legislature within the boundaries of the EAA by the passage of the Act. Under the old common law, a landowner was essentially free to drill a well and pump as much water as he pleased for whatever use and location of use he pleased. Passage of the Act changed the rules within the boundaries of the EAA. The basis for the right to withdraw groundwater under the Act changed from being an incident of the ownership of land to one based on use during the statutorily-defined "historical period," or other criteria. For "exempt" wells, a landowner must now register his well and demonstrate that his well: (1) is incapable of pumping more than 25,000 gallons per day; (2) will be used solely for domestic and livestock use; and (3) is not within or serving a subdivision requiring platting. Regulation under the Act leaves no room for the common law to operate within the boundaries of the EAA with respect to Edwards Aquifer groundwater. As a result, there are no vested property rights which could be taken by the passage of these rules and no TIA need be prepared.

Second, the Authority's action in adopting these rules is an action that is reasonably taken to fulfill an obligation mandated by state law and is thus excluded from the Property Rights Act under §2007.003(b)(4) of the Texas Government Code. *See* §§1.03, (9), (11), (12), (13), and (14), 1.08(a),1.11(a), (b) and (h), 1.14(b) and (c), 1.15(a) and (b), 1.16 (c), 1.17, and 1.33 of the Act.

This conclusion is directly supported by the decision in *Edwards Aquifer Authority v. Bragg*, 21 S.W.3d 375 (Tex. App.-San Antonio 2000, pet. denied) ("*EAA v. Bragg*"). In that case, the Plaintiffs sued to invalidate a set of rules adopted by the Authority (the "prior rules") which were substantially similar, in part, to these rules and which were designed, like these rules, to implement, among other things, the Authority's exempt well program. The Fourth Court of Appeals held that the Authority's adoption of its prior rules was expressly mandated by the Act and was therefore excepted from the operation of the Property Rights Act. The holding in that case controls here.

Third, it is the position of the Authority that all valid actions of the Authority are excluded from the Property Rights Act under §2007.003(b)(11)(C) of the Texas Government Code as actions of a political subdivision taken under its statutory authority to prevent waste or protect the rights of owners of interest in groundwater. Accordingly, a TIA need not be prepared in connection with the proposal of these rules.

Accordingly, for the reasons stated above, a TIA need not be performed in connection with the proposal of these rules.

The new rules in Subchapter C are adopted pursuant to the following statutory provision contained within the Act and other relevant statutory authorities.

Section 1.03(9) of the Act defines "domestic or livestock use." This is the only type of use, as mandated by §1.33 of the Act, for which withdrawals from exempt well may be used.

Section 1.03(11) of the Act defines "industrial use." Section 1.03(12) of the Act defines "irrigation use." These types of uses are not authorized from exempt wells.

Section 1.03(13) of the Act defines "livestock." The Chapter 711 Subchapter C rules incorporate this concept when determining whether a well qualifies as "exempt" from permitting requirements.

Section 1.03(14) of the Act defines "municipal use." The Chapter 711 Subchapter C rules incorporate this concept within the types of uses for which aquifer water may be withdrawn.

Section 1.08(a) of the Act provides that the Authority "has all of the powers, rights, and privileges necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer." This section provides the Authority with broad and general powers to take actions as necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer. These powers are exercised in the adoption of the Subchapter C rules.

Section 1.11(a) of the Act provides that the Board of Directors ("Board") of the Authority "shall adopt rules necessary to carry out the authority's powers and duties under (Article 1 of the Act), including rule governing procedures of the board and the authority." This section provides broad rulemaking authority to implement the various substantive and procedures programs set forth in the Act related to the Edwards Aquifer, including the exempt well program.

Section 1.11(b) of the Act requires the Authority to "ensure compliance with permitting, metering, and reporting requirements and . . . regulate permits." This section, in conjunction with §1.11(a) and (h) of the Act, and §2001.004(1) of the APA, requires the Authority to adopt and enforce the Chapter 711 rules.

Section 1.11(h) of the Act provides, among other things, that the Authority is "subject to" the APA. This section essentially provides that the Authority is required to comply with the APA for its rulemaking, even though the Authority is a political subdivision and not a state agency that would generally be subject to APA requirements.

Section 1.14(b) of the Act imposes, subject to certain limitations, an initial aquifer withdrawal "cap" for permitted withdrawals of 450,000 acre-feet per year, until December 31, 2007. The Chapter 711 Subchapter C rules explain that this cap does not apply to exempt wells.

Section 1.14(c) of the Act imposes, subject to certain limitations, an aquifer withdrawal "cap" for permitted withdrawals of 400,000 acre-feet per year, beginning January 1, 2008. The Chapter 711 Subchapter C rules explain that this cap does not apply to exempt wells.

Section 1.15(a) of the Act directs the Authority to manage all withdrawals from the aquifer and manage all withdrawal points from the aquifer as provided by the Act. This section is implemented in part through the Chapter 711 Subchapter C rules.

Section 1.15(b) of the Act states that "except as provided by §§1.17 and 1.33 of this article, a person may not withdraw water from the aquifer or begin construction of a well or other works designed for the withdrawal of water from the aquifer without obtaining a permit from the authority." This section is implemented in part through the Chapter 711 Subchapter C rules.

Section 1.16(c) of the Act provides that an owner of a well from which the water will be used exclusively for domestic use or watering livestock and that is exempt under §1.33 of the Act is not required to file a declaration of historical use. This concept is incorporated into the Subchapter C rules from Chapter 711.

Section 1.17(a) of the Act provides that a person who, on the effective date of this article, owns a producing well that withdraws water from the aquifer may continue to withdraw and beneficially use water without waste until final action on permits by the Authority, if: (1) the well is in compliance with all statutes and rules relating to well construction, approval, location, spacing, and operation; and (2) by March 1, 1994, the person files a declaration of historical use on a form as required by the Authority. This concept is incorporated into the Chapter 711 rules.

Section 1.17(b) of the Act specifies that use under "interim authorization" may not exceed on an annual basis the historical, maximum, beneficial use of water without waste during any one calendar year as evidenced by the person's declaration of historical use. This concept is incorporated into the Chapter 711 rules.

Section 1.17(c) of the Act specifies that use under "interim authorization" is subject to the Authority's comprehensive management plan and rules. This concept is incorporated into the Chapter 711 rules.

Section 1.17(d) of the Act specifies when use under "interim authorization" ends for a given well. This concept is incorporated into the Chapter 711 rules.

Section 1.29 of the Act outlines the Authority's ability to assess various types of fees to users of the aquifer and others. Certain provisions within this section are relevant to the determination of whether exempt well owners must pay such fees.

Section 1.33 of the Act provides the criteria for exempt wells -- i.e., wells that produce no more than 25,000 gallons of water per day for domestic and livestock use and that are not within or serving a subdivision requiring platting. The section explains that such wells are exempt from metering requirements. However, such wells must be registered with the Authority. These concepts are implemented in Chapter 711, primarily in Subchapter C.

Chapter 36 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 36.101(a) empowers the Authority to make and enforce rules to provide for conserving, preserving, protecting, and recharging of the groundwater in order to, among other things, prevent waste and carry out the duties provided elsewhere in Chapter 36. This requirement is implemented, in large part, through the Chapter 711 rules.

Chapter 36 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 36.117 allows districts such as the Authority to exempt certain wells from permitting requirements based on criteria similar to §1.33 of the Act.

Chapter 36 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 36.119(a) decrees that drilling a well without a required permit or operating a well at a higher rate of production than the rate approved for the well is declared to be illegal, wasteful per se, and a nuisance. This concept is incorporated into the Chapter 711 rules.

Chapter 49 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 49.211(a) endows districts such as the Authority with the "functions, powers, authority, rights, and duties that will permit accomplishment of the purposes for which it was created or the purposes authorized by the constitution, this code, or any other law." This broad delegation of powers is incorporated into the Chapter 711 rules.

The Act specifies that certain wells are exempt from metering and permitting requirements unless they are within or serving a subdivision required to be platted. Thus, it is necessary in Subchapter C of the Chapter 711 rules to apply platting and subdivision concepts found in Chapter 212 and 232 of the Texas Local Government Code. Section 212.004 defines when a municipality may require a subdivision of land to be platted. Section 212.0046 provides municipalities an exception from the platting requirements for certain land abutting an aircraft runway. Section 212.013 provides a mechanism for the vacating of a plat. Section 232.001 defines when a county may require a subdivision of land to be platted. Section 232.0015 provides counties numerous exceptions from the platting requirement. Section 232.008 provides a mechanism for the cancellation of a subdivision. The concepts in these sections are incorporated into the Subchapter C rules.

§711.18. Definitions.

The following words and terms, when used in this subchapter, shall have the following meanings unless the context clearly indicates otherwise:

(1) Divide or division--To cut into parts, disunite, or separate a tract of land regardless of whether it is made by using a:

(A) metes and bounds description in a deed of conveyance;

(B) metes and bounds description in a contract for a deed;

(C) contract of sale to convey;

(D) any other executory contract to convey; or

(E) any other method.

(2) Plat--A map of specific tracts of land showing the location and boundaries of individual tracts of lands subdivided into other smaller tracts with streets, alleys, squares, parks, or other parts of a tract of land, and easements drawn to scale.

(3) Subdivision of land--When an owner of a tract of land within the boundaries of the Authority divides the tract into two or more parts to lay out:

(A) a subdivision of the tract, including an addition;

(B) lots; or

(C) streets, alleys, squares, parks, or other parts of the tract intended to be dedicated:

(i) to public use; or

(ii) for the use of purchasers or owners of lots fronting on or adjacent to the streets, alleys, squares, parks or other parts.

(4) Tract of land--A lot, piece, or parcel of land irrespective of size.

§711.22. Effect of Exempt Well Status.

(a) Except as provided in subsection (b) of this section, all provisions of the Act and the authority's rules apply to owners of exempt wells.

(b) The owner of an exempt well is not required to comply with the requirements of:

(1) subchapter M of this chapter (relating to Meters; Alternative Measuring Methods; and Reporting);

(2) section 711.12(a)(1) of this chapter (relating to Activities Requiring a Permit);

(3) section 707.311 of this title (relating to Requirement to File Declaration of Historical Use); and

(4) subchapters D (relating to Aquifer Management Fees) and E (relating to Permit Retirement Special Fees) of chapter 709 (relating to Fees).

(c) Unless the well status is converted pursuant to §711.48 of this chapter (relating to Conversion of Well Status), the owner of an exempt well may not obtain a groundwater withdrawal permit for the well, nor will the well qualify for interim authorization status.

§711.32. Production Limitation.

The owner of an exempt well may not produce more than 25,000 gallons of water a day. Such a well must also be either drilled, completed , or equipped so that it is incapable of producing more than 25,000 gallons per day.

§711.34. Platting of Subdivisions.

(a) Except as provided in subsection (b) of this section, subdivisions of land are classified as requiring platting.

(b) The following subdivisions of land are not classified as requiring platting:

(1) The owner of a tract of land located outside the limits and the extraterritorial jurisdiction of a municipality divides the tract into two or more parts, but:

(A) does not lay out streets, alleys, squares, parks, or other parts of the tract intended to be dedicated to public use or for the use of purchasers or owners of lots fronting on or adjacent thereto; and

(B) the tract is to be used primarily for agricultural use, as defined in Section 1-d, Article VIII, Texas Constitution, or for farm, ranch, wildlife management, or timber production use within the meaning of Section 1-d-1, Article VIII, Texas Constitution.

(2) The owner of a tract of land located outside the limits and the extraterritorial jurisdiction of a municipality:

(A) divides the tract into four or fewer parts;

(B) does not lay out streets, alleys, squares, parks, or other parts of the tract intended to be dedicated to public use or for the use of purchasers or owners of lots fronting on or adjacent thereto; and

(C) each lot is to be sold, given, or otherwise transferred to an individual who is related to the owner of the tract within the third degree by consanguinity or affinity, as determined under Chapter 573, Government Code;

(3) The owner of a tract of land located outside the limits and the extraterritorial jurisdiction of a municipality:

(A) divides the tract into two or more lots and each lot of the subdivision is more than 10 acres in area; and

(B) does not lay out streets, alleys, squares, parks, or other parts of the tract intended to be dedicated to public use or for the use of purchasers or owners of lots fronting on or adjacent to thereto;

(4) The owner of a tract of land located outside the limits and the extraterritorial jurisdiction of a municipality:

(A) divides the tract into two or more lots;

(B) sells all of the lots to veterans through the Veterans Land Board program; and

(C) the owner does not lay out streets, alleys, squares, parks, or other parts of the tract intended to be dedicated to public use or for the use of purchasers or owners of lots fronting on or adjacent to thereto;

(5) The subdivision is a tract of land owned by the state or any state agency, board, or commission, or owned by the permanent school fund or any other dedicated funds of the state, unless the subdivision lays out streets, alleys, squares, parks, or other parts of the tract intended to be dedicated to public use or for the use of purchasers or owners of lots fronting on or adjacent to thereto;

(6) The owner of a tract of land located outside the limits and the extraterritorial jurisdiction of a municipality divides the tract into two or more lots and:

(A) the tract is owned by a political subdivision of the state;

(B) the tract is situated in a flood plain; and

(C) the lots are sold to adjoining landowners;

(7) The owner of a tract of land located outside the limits and the extraterritorial jurisdiction of a municipality divides the tract into two lots and:

(A) does not lay out streets, alleys, squares, parks, or other parts of the tract intended to be dedicated to public use or for the use of purchasers or owners of lots fronting on or adjacent to thereto;

(B) ownership of at least one new part is to be retained by the owner of the larger, subdivided tract; and

(C) ownership of the other new part is to be transferred to another person who will further subdivide the tract subject to the plat filing requirements of chapter 232, Local Government Code;

(8) The owner of a tract of land located outside the limits and the extraterritorial jurisdiction of a municipality:

(A) divides the tract into two or more lots;

(B) does not lay out streets, alleys, squares, parks, or other parts of the tract intended to be dedicated to public use or for the use of purchasers or owners of lots fronting on or adjacent to thereto;

(C) transfers all lots to persons who owned an undivided interest in the original tract; and

(D) a plat is filed before any further development of any part of the tract;

(9) The owner of a tract of land located within the limits or the extraterritorial jurisdiction of a municipality divides the tract into parts greater than five acres, where each part has access and no public improvement is being dedicated;

(10) The owner of a tract of land located wholly within the limits of a municipality with a population of 5,000 or less divides the tract into parts larger than 2 1/2 acres and the tract abuts any part of an aircraft runway; or

(11) the subdivision of land:

(A) the subdivision occurred prior to the effective date of the Chapter 711 subchapter C rules; and

(B) when final action is taken on an application for exempt well status;

(i) the subdivision does not have retail water service; and

(ii) the subdivision is not scheduled by a municipal distribution system to be provided retail water service within one year from the date the application for exempt well status was filed with the Authority.

§711.46. Dual Status Wells Prohibited.

(a) A well may either be an exempt well or a well for which a permit is required, but not both simultaneously.

(b) If separately metered in accordance with the requirements of §711.402(e) of this title (relating to Duty to Install and Operate Meter; Meter Installation Deadlines) of this chapter, withdrawals for exempt use may be made from a permitted non-exempt irrigation well.

(c) Withdrawals for uses requiring a groundwater withdrawal permit may not be made from an exempt well.

§711.48. Conversion of Well Status.

(a) The owner of a well for which a permit is required may apply to convert the well to an exempt well if the well otherwise meets the requirements to qualify for an exempt well and the person files an application for exempt well status pursuant to §707.308 of this chapter (relating to Requirement to File Application for Exempt Well Status).

(b) The owner of an exempt well may apply to convert the well to a non-exempt permitted well if the owner files an application to transfer and amend pursuant to §707.414 of this title (relating to Applications to Transfer Interim Authorization Status and Amend Application for Initial Regular Permit), or §707.415 of this title (relating to Applications to Transfer and Amend Permit). Except as provided in §711.146 of this chapter (relating to Dual Status Wells Prohibited), if such a well is converted to a non-exempt, permitted well, then all withdrawals from the well for exempt purposes must cease.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009045
Gregory M. Ellis
General Manager
Edwards Aquifer Authority
Effective date: January 17, 2001
Proposal publication date: September 29, 2000
For further information, please call: (210) 222-2204

♦ ♦ ♦

SUBCHAPTER D. INTERIM AUTHORIZATION

31 TAC §§711.60, 711.62, 711.64, 711.66, 711.68, 711.70, 711.72, 711.74

The Edwards Aquifer Authority (the "Authority") adopts new 31 TAC §§711.60, 711.62, 711.64, 711.66, 711.68, 711.70, 711.72, and 711.74 (the "Chapter 711 Subchapter D rules"), relating to the Authority's implementation of the interim authorization aspects of its Groundwater Withdrawal Permits Program during which certain withdrawals from the Edwards Aquifer ("Aquifer") may continue to be made pending issuance of groundwater withdrawal permits by the Authority. Section 711.70 is adopted with changes to the proposed text as published in the September 29, 2000 issue of the *Texas Register* (25 TexReg 9878) and is republished herein. Sections 711.60, 711.62, 711.64, 711.66, 711.68, 711.72, and 711.74 are adopted without changes to the proposed text and will not be republished.

The Edwards Aquifer Authority Act, Act of May 30, 1993, 73rd Legislature, Regular Session, Chapter 626, 1993 TEXAS GENERAL LAWS 2350, as amended by Act of May 28, 1995, 74th Legislature, Regular Session, Chapter 3189, 1995 TEXAS GENERAL LAWS 2505, Act of May 16, 1995, 74th Legislature, Regular Session, Chapter 361, 1995 TEXAS GENERAL LAWS 3280, and Act of May 6, 1999, 76th Legislature, Regular Session, Chapter 163, 1999 TEXAS GENERAL LAWS 634 (the "Act"), requires the Authority to implement a permitting system whereby "existing users" of groundwater from the Aquifer may apply for and receive initial regular permits issued by the Authority allowing for the withdrawal of groundwater from the Aquifer. Other types of permits are also required by the Act for other types of withdrawals, as well as for well construction and related activities. Recognizing that the Authority could not instantaneously issue permits to existing users, the Legislature included §1.17 in the Act, which provides for an "interim authorization" period prior to the issuance by the Authority of final initial regular permits during which certain existing users of the Aquifer are generally allowed to continue to withdraw and use Aquifer water until final action on permit applications by the Authority. Thus, the interim authorization period provides a transition period during which existing users' rights to withdraw water from the aquifer transition from deriving from the common law to deriving from the new statutory-based permitting system embodied in the Act. The Act imposes a number of restrictions upon withdrawals from the Aquifer during the interim authorization period. The Chapter 711 subchapter D rules are intended to effectuate the various components of the Act related to the interim authorization period.

The new sections are adopted pursuant to the following statutory provisions contained within the Act.

Section 1.03(11) of the Act defines "industrial use." Section 1.03(12) of the Act defines "irrigation use." Section 1.03(14) of the Act defines "municipal use." The Act interprets these sections as defining the beneficial uses to which groundwater withdrawn from the Aquifer may be placed during the interim authorization period.

Section 1.08(a) of the Act provides that the Authority "has all of the powers, rights, and privileges necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer." The Authority interprets this section to provide the Authority with broad and general powers to take actions as necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer during the interim authorization period.

Section 1.11(a) of the Act provides that the Board of Directors ("Board") of the Authority "shall adopt rules necessary to carry out the authority's powers and duties under (Article 1 of the Act), including rule governing procedures of the board and the authority." The Authority interprets this section to require the Authority to adopt rules to implement the various substantive and procedures programs set forth in the Act related to the Edwards Aquifer, including the interim authorization program.

Section 1.11(b) of the Act requires the Authority to "ensure compliance with permitting, metering, and reporting requirements and . . . regulate permits." The Authority interprets this section, in conjunction with §1.11(a) and (h) of the Act, and §2001.004(1) of the APA, to require the Authority to adopt and enforce rules related to the Authority's permit program, an aspect of which is the interim authorization rules.

Section 1.15(a) of the Act directs the Authority to manage withdrawals from the aquifer and manage all withdrawal points from the aquifer as provided by the Act. The Authority interprets this section to authorize the Authority to manage withdrawals and withdrawal points during the interim authorization period.

Section 1.15(b) of the Act states that "except as provided by §§1.17 and 1.33 of this article, a person may not withdraw water from the aquifer or begin construction of a well or other works designed for the withdrawal of water from the aquifer without obtaining a permit from the authority." The Authority interprets this section to authorize withdrawals of groundwater from the Aquifer during the interim authorization period without a groundwater withdrawal permit. In addition, this section authorizes the Authority to regulate well construction during the interim authorization period.

Section 1.17(a) of the Act provides that a person who, on the effective date of Article 1 of the Act (i.e. June 28, 1996), owns a producing well that withdraws water from the aquifer may continue to withdraw and beneficially use water without waste until final action on permits by the Authority, if: (1) the well is in compliance with all statutes and rules relating to well construction, approval, location, spacing, and operation; and (2) by March 1, 1994, [1] the person files a declaration of historical use on a form as required by the Authority. The Authority interprets this section to provide the basic authority for an existing user to continue to make withdrawals from the Aquifer during the interim authorization period. This section also provides the start date for the interim authorization period.

[1] This March 1, 1994 date was changed by the Texas Supreme Court to December 28, 1996. See Barshop v. Medina Under. Wat. Cons. Dist., 925 S.W.2d 618 (Tex. 1996).

Section 1.17(b) of the Act specifies that use under interim authorization may not exceed on an annual basis the historical, maximum, beneficial use of water without waste during any one calendar year as evidenced by the person's declaration of historical use, unless otherwise provided by the Authority. The Authority interprets this section to place limits on the amount of groundwater that an existing user may annually withdraw from the Aquifer.

Section 1.17(c) of the Act specifies that use under interim authorization is subject to the Authority's comprehensive management plan and rules. The Authority interprets this section to authorize the Authority to issue rules to regulate withdrawals from the Aquifer during the interim authorization period. Additionally, this section authorizes the placing of conditions on the withdrawal of groundwater from the Aquifer during the interim authorization period.

Section 1.17(d) of the Act specifies when use under interim authorization ends for a given well. The Authority interprets this section as defining when the interim authorization period ends.

The Subchapter D Rules

Section 711.60 specifies the criteria under which a well qualifies for interim authorization status. A well qualifies if, on December 30, 1996, its was a producing, non-exempt well owned by a person who filed a timely permit application and is an "existing user." This rule establishes specific qualifying requirements for interim authorization status, thereby preventing persons or entities from continuing to make withdrawals from non-exempt wells if they do not meet the criteria in this section. By providing clear parameters for qualification, §711.60 ensures consistency and predictability in determining which wells qualify for interim authorization status. The factual basis for this rule is the existence of §1.17(a) of the Act on which this section is based and tracks and which expressly authorizes interim authorization withdrawals under the conditions contained in §711.60. Additionally, the requirement that the owner with interim authorization status be an "existing owner" is necessary to avoid potential conflicts between those who might claim interim authorization status for the same well, or persons that may claim interim authorization status even though they never had historical use during the historical period. The Authority has defined "existing owner" in §711.1(2) so the public can determine whether they are eligible for interim authorization status.

Section 711.62 explains that a person owning a well qualifying for interim authorization status may continue to use the well to withdraw and beneficially use aquifer water during the interim authorization period. The purpose of this section it to describe the effect of interim authorization status. It confirms that until the period ends, the owner of a qualifying well may continue to withdraw aquifer water. Section 711.62 also confirms that while the interim authorization period is transitional, well owners are still required to use aquifer water beneficially and not waste it. The factual basis for this rule is the existence of §1.17(a) of the Act on which §711.62 is based and explains the effect of interim authorization status.

Section 711.64 explains that interim authorization withdrawals are made pursuant to §1.17 of the Act. Section 1.17 of the Act provides for interim authorization and illustrates that the Legislature recognized the need to allow withdrawals pending final action on permit applications. Section 711.64 makes clear to the public that interim authorization withdrawals are based on the Act and not the common law or groundwater withdrawal permits. The factual basis for this rule is §1.17(a) of the Act upon which §711.64 is based and authorizes interim authorization withdrawals.

Section 711.66 specifies that the interim authorization period begins on December 30, 1996, and ends, for any particular well, on either December 30, 1996, if no timely permit application was submitted for the well, or on January 1st after the date that the board issues a final and appealable order acting on the application for that well. The factual basis for §711.66(1) is the existence of §1.17(a) and (d)(1) of the Act upon which this section is based and provides the beginning dates for the interim authorization period.

An additional factual basis is that the December 30, 1996 deadline to file a declaration follows the intent of the Act which is to allow six months after the effective date of the Act to file the declaration. This was established in *Barshop v. Medina Under. Wat. Cons. Dist.*, 925 S.W.2d 618 (Tex. 1996). After legal challenges to the Act, the Texas Supreme Court in *Barshop* validated the Act effective June 28, 1996, the date of the decision. Providing water users the six months intended by the Act resulted in the December 30, 1996 deadline used in §711.66. This factual basis also provides the basis for §711.66(2)(A).

For those users who met the December 30, 1996 deadline to file a declaration, §711.66 states that their period of interim authorization ends on January 1 after the date the board issues a final and appealable order acting on the declaration. The factual basis for §711.66(2)(B) is that the Authority determined it was necessary to use January 1 after the date of the order so the water user would maintain a single user status for the entire year, allowing for effective water management. Having a water user go from withdrawing under interim authorization status to withdrawing under an initial regular permit in a single year would create major difficulties in resource planning, reporting, administration and enforcement matters.

Section 711.68 specifies that the water withdrawn from a well qualifying for interim authorization status may be put to use only for the purposes of use designated in the application and falling within one of the following three categories: industrial, municipal and irrigation use. The authorized uses of industrial, municipal and irrigation are derived from the Act and are listed in this section to ensure land owners properly use the groundwater withdrawn from the aquifer under interim authorization status. The rule informs the user that water withdrawn during this period must be beneficially used and not wasted. The factual basis for this rule is the existence of the definitions in §§1.03(11), (12) and (14) of the Act upon which this rule is based and setting forth the beneficial uses recognized in the Act.

Section 711.70 specifies the amount of water which can be withdrawn from a well qualifying for interim authorization status and the factual basis for this rule is the existence of §1.17(b) of the Act upon which this rule is based. That amount may not exceed the lesser of the person's maximum beneficial use during any one year of the statutory historical period as claimed in the person's application, or, if the person is an applicant in a contested case hearing that has been pending before SOAH for a period of at least one year, an amount otherwise determined by the board. The purpose of this rule is to identify the permissible volume of groundwater that may be withdrawn under interim authorization. By providing notice to well owners of these parameters, they are better able to engage in appropriate technical and budgetary planning. Further, by authorizing the Authority to determine the amount in certain circumstances, §711.70 provides some flexibility that may be required given the particular facts of a case and allows an existing user to plan on the amount of water recognized in §711.70(1) for a reasonable period of time prior to the Authority exercising its authority under §711.70(2).

Section 711.72 states that withdrawals of aquifer water from a well qualifying for interim authorization status are subject to various "Standard Groundwater Withdrawal Conditions" specified in subchapter F of Chapter 711, 31 Texas Administrative Code, rules, as well as all applicable laws relating to well construction, well approval, well location, well spacing, and well operation. By applying conditions on the withdrawal of groundwater under interim authorization, the Authority ensures protection of water quality, maximization of beneficial use of aquifer water, and compliance with the Act and the Authority's rules. It is important to all users of the aquifer that the Authority maintain its standards for wells operating under interim authorization. The factual basis for this rule is the existence of §1.14(a) and §1.17(a)(1) of the Act and subchapter F of Chapter 711, upon which this rule is based.

Section 711.74 explains that no action taken by the Authority's board or general manager during the interim authorization period will be binding upon the Authority or the applicant with respect to any issues arising in a permit application. The factual basis for this rule is that the Authority has determined this rule is necessary to separate administrative decisions made during the interim authorization period and during the permit period. Section 711.74 provides assurance to both the applicant and the Authority that neither will be bound by actions taken during this period.

Section 2001.0225 of the Texas Government Code requires an agency to perform, under certain circumstances, a regulatory analysis of major environmental rules ("RIAMER"). There are two primary components that must be met before a RIAMER is required. First, no RIAMER need be prepared if the rules in question are not "major environmental rules" or "MERs." Second, even if the rules are MERs, no RIAMER need be prepared if adoption of the MERs would not result in any one of the following criteria listed in §2001.0225(a)(1)-(4):

1. the MER would "exceed" a standard set by federal law, unless the MER is specifically required by state law;

2. the MER would "exceed" an express requirement of state law, unless the MER is specifically required by federal law;

3. the MER would "exceed" a requirement of a delegation agreement or contract between the state and an agency or representative of the federal governmental to implement a state and federal program; or

4. the MER is adopted solely under the "general powers" of the agency instead of under a specific state law.

The Act requires the Authority to implement a permitting system. However, the Act provides for an "interim authorization" period during which existing users who filed timely permit applications are generally allowed to continue to withdraw and use aquifer water until final action on permits by the Authority. The Chapter 711 Subchapter D rules essentially set forth: the criteria under which a well qualifies for interim authorization status, the effect of qualifying for interim authorization status, the duration of the interim authorization period, the uses of aquifer water authorized during the interim authorization period, the withdrawal amounts authorized during the interim authorization period, and the conditions applicable during the interim authorization period.

Section 711.70 provides some limitations on the legal authority to withdraw groundwater from the aquifer which did not exist under the common law. These withdrawal limitations would tend to have an environmental protection aspect. Therefore, §711.70 of subchapter D has the specific intent to "protect the environment" and might constitute a MER. The other Subchapter D rules do not have the specific intent to protect the environment or reduce risks to human health from environmental exposure and are, therefore, not MERs.

However, without determining whether §711.70 constitutes a MER, the Authority has concluded that no RIAMER need be prepared for any of the Subchapter D rules because none of them meet any of the criteria listed in APA §2001.0225(a)(1)-(4). First, the rules in Subchapter D do not exceed a standard set by federal law. The only reasonably related federal law establishes the Sole Source Aquifer Program implemented by the EPA for portions of the Edwards Aquifer, which applies only to federally-funded projects conducted on the aquifer. There is no federal law that specifically requires permitting for withdrawals of Edwards Aquifer groundwater or an interim authorization period prior to implementation of such a permitting program. Therefore, the Subchapter D rules do not exceed a standard set by federal law. Moreover, even if the rules did exceed a standard set by federal law, the rules are specifically required by state law which requires the Authority to manage withdrawals from the aquifer, adopt rules to carry out its powers and duties under the Act, manage withdrawals and points of withdrawals from the aquifer and require permits for certain withdrawals, and implement an interim authorization period to be in effect prior to issuance of permits (pursuant to, *inter alia*, §§1.03(9), (11), (12), (13) and (14), 1.08(a), 1.11(a), (b), and (h), 1.15(a) and (b), 1.16(c), 1.17, and 1.33(a), (b) and (c) of the Act).

Second, the Subchapter D rules do not exceed an express requirement of state law. Instead, the rules are designed to carry out the Authority's statutory responsibility to manage withdrawals from the aquifer, adopt rules to carry out its powers and duties under the Act, manage withdrawals and points of withdrawals from the aquifer and require permits for certain withdrawals, and implement an interim authorization period to be in effect prior to issuance of permits (pursuant to, *inter alia*, §§1.03(9), (11), (12), (13) and (14), 1.08(a), 1.11(a), (b), and (h) 1.15(a) and (b), 1.16(c), 1.17, and 1.33(a), (b) and (c) of the Act). The rules are designed to comply with these express requirements of state law and not exceed them. Other than the Act, there are no other "express requirements of state law" which are applicable to these rules or which could be exceeded by these rules.

Third, the Subchapter D rules do not exceed a requirement of a delegation agreement or contract between the State of Texas and an agency or representative of the federal government to implement a state and federal program. The subject matter of the rules is not covered by any delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program.

Fourth, the Subchapter D rules would not be adopted solely under the general powers of the Authority instead of under a specific state law. While these rules are adopted in part under the Authority's general powers, they are also adopted under the Act, a specific state law regarding the Edwards Aquifer. In particular, the rules are adopted pursuant to, §§1.03(9), (11), (12), (13) and (14), 1.08(a), 1.11(a), (b), and (h), 1.15(a) and (b), 1.16(c), 1.17, and 1.33(a), (b) and (c) of the Act, which require the Authority to manage withdrawals from the aquifer, adopt rules to carry out its powers and duties under the Act, manage withdrawals and points of withdrawals from the aquifer and require permits for certain withdrawals, and implement an interim authorization period to be in effect prior to issuance of permits.

For these reasons, it is not necessary to perform a RIAMER on the Subchapter D rules.

Five public hearings were held on the Chapter 711 Subchapter D rules and other rules proposed by the Authority on: Monday, October 2, 2000 at 6:00 p.m. at the conference center of the Edwards Aquifer Authority, 1615 N. St. Mary's Street, San Antonio, Texas; Tuesday, October 3, 2000 at 6:00 p.m., at St. Paul's Lutheran Church, 1303 Avenue M, Hondo, Texas; Wednesday, October 4, 2000 at 6:00 p.m., at the San Marcos Activity Center, 501 E. Hopkins, San Marcos, Texas; Wednesday, October 11, 2000 at 6:00 p.m., at the Sgt. Willie DeLeon Civic Center, 300 E. Main Street, Uvalde, Texas; and Thursday, October 12, 2000, at 6:00 p.m., at the New Braunfels Civic Center, 380 S. Seguin Avenue, New Braunfels, Texas.

The public comment period closed on October 30, 2000. Oral and/or written comments were provided by San Antonio Water System ("SAWS"), Joe Ptak, and Texas Farm Bureau ("TFB").

Section 711.60

Public Comment No. 1:

SAWS asserts interim authorization is available to succeeding well owners if a declaration was timely filed and withdrawals were made from a well during the historical period. Therefore, SAWS suggests §711.60 which reads as proposed:

A well qualifies for interim authorization status if, on December 30, 1996, it was a producing, non-exempt well from which the person owning the well, who is an existing user and timely filed a declaration, made withdrawals of groundwater from the aquifer.

be modified to read:

A well qualifies for interim authorization status if, on December 30, 1996, it was a producing, non-exempt well *if the person owning the well timely filed a declaration, and withdrawals of groundwater from the aquifer were made from the well during the historical period.*

Authority Response:

The Authority staff received the above-referenced comment and disagrees with the proposed modification. SAWS' comment that interim authorization is available to succeeding well owners under certain circumstances is already recognized by the Authority with the use of the term "existing user" in §711.60. The definition of "existing user" adopted by the Authority in rule 711.1(2) expressly includes "a person or the successor in interest of such a person . . .." Therefore, §711.60, as proposed, properly includes the use of the term "existing user" which encompasses the point made by SAWS relating to the succeeding well owners. In light of this discussion, §711.60 has not been modified.

Section 711.68

Public Comment No. 2:

SAWS argues interim authorization may be transferred as to place and purpose of use. Purpose of use, according to SAWS, should not be restricted to the original purpose of use because it may preclude land use changes. SAWS requests §711.68 be modified from:

". . . may beneficially use groundwater withdrawn from the aquifer through the well *only* for the purpose(s) of use designated in the persons' declaration . . ..."

to the following version which deletes the word "only":

". . . may beneficially use groundwater withdrawn from the aquifer through the well for the purpose(s) of use designated in the persons' declaration . . .."

Authority Response:

The Authority staff received the above-referenced comment and disagrees with the proposed modification. Section 711.68 provides the permissible range of uses of groundwater withdrawn from the aquifer during the interim authorization period. The authorized uses of industrial, municipal and irrigation are derived from the Act and are listed in this rule to ensure land owners properly use groundwater withdrawn from the aquifer. Whether the place or purpose of use of a well's interim authorization status can be transferred is addressed in separate rules found in subchapter L (relating to transfers). That determination is not related to or limited by §711.68. In light of this discussion, §711.68 has not been modified.

Section 711.70

Public Comment No. 3:

SAWS points out that despite the fact that the Act provides for an interim authorization amount that is different than the declared maximum beneficial use under §1.17(b), it does not seem possible for such a change to occur without the prior issuance of a "final and appealable order" by the Authority's board. SAWS states that under the proposed rule, it will be bound by the board's decision with no mechanism to challenge the decision. SAWS proposes the elimination of paragraph (2) which reads "an amount otherwise determined by the Board for the person" so that §711.70 reads:

During a well's interim authorization period, a person owning a well qualifying for interim authorization status may withdraw on an annual basis an amount not to exceed the person's historical, maximum beneficial use claimed in §4B of a declaration.

Authority Response:

The Authority staff received the above-referenced comment and disagrees with the proposed modification. Section 1.17(b) of the Act specifically states that use under interim authorization may not exceed the historical, maximum beneficial use of water as evidenced by a declaration unless that amount is "otherwise determined by the Authority." Clearly, the Act authorizes the Authority to set a withdrawal amount. While the Authority is made "subject to" the Administrative Procedures Act ("APA") under the Act, this does not mean every decision of the Authority must be made following the opportunity for contested case procedures or be subject to judicial review or appeal. Due process is a flexible concept and calls for such procedural protections as a particular situation demands. The Authority believes the requirements of procedural due process are satisfied at a properly noticed open meeting where a holder of interim authorization status has the opportunity to voice its position on the withdrawal amount before such a decision is made by the board.

While the Authority does not agree with SAWS' proposal to eliminate paragraph (2) for the reasons stated above, it does believe the language requires modification to clarify the board's involvement in determining the withdrawal amount. Therefore, paragraph (2) has been modified to read:

(B) *if the person is an applicant in a contested case hearing that has been pending before SOAH for a period of at least one year*, an amount otherwise determined by the Board.

Public Comment No. 4:

Ptak commented that the phrase "otherwise determined by the Board" should be expanded or clarified. In addition, he proposes an addition to the rule of a performance audit for each permit issued by the Authority to ensure water is being used beneficially and is not being wasted.

Authority's Response:

The Authority staff received the above-referenced comment and agrees the rule should be modified to clarify the board's involvement in determining the withdrawal amount. Therefore, paragraph (2) has been modified to read:

(2) *if the person is an applicant in a contested case hearing that has been pending before SOAH for a period of at least one year*, an amount otherwise determined by the Board.

The Authority disagrees with Mr. Ptak's proposal to add provisions for a performance audit under interim authorization status because there is no need to duplicate procedures proposed in other rules. Section 711.414(b) in subchapter M (relating to Meters), requires persons with interim authorization status to file a written groundwater use report with the Authority. In addition, there are other sections authorizing the Authority to enter the land (§711.416) and to take enforcement action, if necessary, if withdrawals are not being metered properly (§711.420). These provisions will allow the Authority to monitor wells with interim authorization status to ensure that water withdrawn from the aquifer is beneficially used and not wasted. In light of this discussion, §711.70 has not been modified.

General

Public Comment No. 5:

TFB maintains that a takings impact statement ("TIA") was required before the Authority provided public notice of the proposed rules. According to TFB, the Texas Private Real Property Rights Preservation Act ("Property Rights Act") does not excuse the Authority from the requirements of the Property Right Act because the rights are not "vested" or because the Legislature has chosen to regulate those property rights. Furthermore, the TFB contends that property does not have to be vested to come within the purview of the Property Rights Act and, nonetheless, groundwater rights are vested rights requiring no perfection because they accompany the surface estate.

Authority's Response:

The Authority has received this comment and disagrees with it. Chapter 2007 of the Texas Government Code, the Property Rights Act referred to by the TFB, requires governmental entities, under certain circumstances, to prepare a TIA in connection with certain covered categories of proposed governmental actions. Based on the following reasons, the Authority has determined that it need not prepare a TIA in connection with the adoption of these rules.

First, the Authority has made a "categorical determination" that these Chapter 711 rules do not affect vested property rights and, as such, adoption of these rules is not an action that "may result in a taking." The rules at issue here implement a program regulating aquifer withdrawals prior to the issuance of final permits by the Authority. The Act specifies an interim authorization period prior to the issuance by the Authority of final permits during which certain existing users of the aquifer may continue to make withdrawals. The Act imposes a number of restrictions upon the use of the aquifer during the interim authorization period. These rules are intended to effectuate these various components of the Act.

The Texas Private Real Property Rights Preservation Act makes it clear that a TIA need only be performed when the proposed governmental action is one that "may result in a taking." *See id.*, §§2007.043(a), 2007.041(a), 2007.042(a). If an action is one that has no potential to result in a taking, then no TIA need be performed. Adoption of the rules at issue here is not an action that "may result in a taking" for two reasons.

The rules cannot result in the taking of a vested private real property right. Traditional takings doctrine dictates that, in order to constitute a compensable taking, the property right alleged to have been "taken" must rise to the level of a *vested* right. Prior to the adoption of the Act, a landowner's right to pump groundwater underlying his or her property derived from the common law English Rule, also known as the "Rule of Capture." The proposed rules implement an interim authorization program during which groundwater withdrawals may be regulated and limited. This is arguably at odds with the Rule of Capture. However, a landowner's common law Rule of Capture right does not rise to the level of a vested property right. Under the common law, water underlying a landowner's property may be reduced to possession by the pumping of another. In other words, a landowner has no right to exclude others from the water underlying his land. As such, the landowner's expectancy of water does not rise to the level of a vested property right which could be "taken" by the passage of these rules and passage of these rules is not an action that may result in a taking.

Additionally, with respect to Edwards Aquifer water, any common law rights a landowner may have had in the past have been effectively abolished by the Legislature within the boundaries of the EAA by the passage of the Act. Under the old common law, a landowner was essentially free to drill a well and pump as much water as he pleased for whatever use and location of use he pleased. Passage of the Act changed the rules within the boundaries of the EAA. The basis for the right to withdraw groundwater under the Act changed from being an incident of the ownership of land to one generally based on use during the statutorily-defined "historical period." *See* Act §1.16. Excluding "exempt" wells, in order to operate an existing well during the interim authorization period, a landowner must have filed a timely permit application with the Authority and the well must be in compliance with all statutes and rules relating to well operation, construction, approval, location, and spacing. The quantity of withdrawals are limited and other restrictions apply. *See* Act §1.17. Regulation under the Act leaves no room for the common law to operate within the boundaries of the EAA with respect to Edwards Aquifer groundwater. As a result, there are no vested property rights which could be taken by the adoption of these rules and no TIA need be prepared.

Second, the Authority's action in adopting these rules is an action that is reasonably taken to fulfill an obligation mandated by state law and is thus excluded from the Texas Private Real Property Rights Preservation Act under §2007.003(b)(4) of the Texas Government Code. *See* §§1.03(9), (11), (12), (13), and (14), 1.08(a), 1.11(a), (b), and (h), 1.15(a) and (b), 1.16(c), 1.17, 133, of the Act, This conclusion is supported by the decision in *Edwards Aquifer Authority v. Bragg*, 21 S.W.3d 375 (Tex. App.-San Antonio 2000, pet. filed) ("*EAA v. Bragg*"). In that case, the Plaintiffs sued to invalidate a set of rules adopted by the Authority (the "prior rules") which included rules substantially similar to these rules and which were designed, like these rules, to implement the Authority's interim authorization program. The Fourth Court of Appeals held that the Authority's adoption of its prior rules was expressly mandated by the Act and was therefore excepted from the operation of TPRPRPA. *Id.* at 379-80. The holding in that case controls here.

Third, it is the position of the Authority that all valid actions of the Authority are excluded from the Texas Private Real Property Rights Preservation Act under §2007.003(b)(11)(C) of the Texas Government Code as actions of a political subdivision taken under its statutory authority to prevent waste or protect the rights of owners of interest in groundwater.

Accordingly, for the reasons stated above, a TIA need not be performed in connection with the adoption of these rules.

The new sections are adopted pursuant to the following statutory provisions contained within the Act.

Section 1.03(11) of the Act defines "industrial use." Section 1.03(12) of the Act defines "irrigation use." Section 1.03(14) of the Act defines "municipal use." The Act interprets these sections as defining the beneficial uses to which groundwater withdrawn from the Aquifer may be placed during the interim authorization period.

Section 1.08(a) of the Act provides that the Authority "has all of the powers, rights, and privileges necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer." The Authority interprets this section to provide the Authority with broad and general powers to take actions as necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer during the interim authorization period.

Section 1.11(a) of the Act provides that the Board of Directors ("Board") of the Authority "shall adopt rules necessary to carry out the authority's powers and duties under [article 1 of the Act], including rule governing procedures of the board and the authority." The Authority interprets this section to require the Authority to adopt rules to implement the various substantive and procedures programs set forth in the Act related to the Edwards Aquifer, including the interim authorization program.

Section 1.11(b) of the Act requires the Authority to "ensure compliance with permitting, metering, and reporting requirements and . . . regulate permits." The Authority interprets this section, in conjunction with §1.11(a) and (h) of the Act, and §2001.004(1) of the APA, to require the Authority to adopt and enforce rules related to the Authority's permit program, an aspect of which is the interim authorization rules.

Section 1.15(a) of the Act directs the Authority to manage withdrawals from the aquifer and manage all withdrawal points from the aquifer as provided by the Act. The Authority interprets this section to authorize the Authority to manage withdrawals and withdrawal points during the interim authorization period.

Section 1.15(b) of the Act states that "except as provided by §§1.17 and 1.33 of this article, a person may not withdraw water from the aquifer or begin construction of a well or other works designed for the withdrawal of water from the aquifer without obtaining a permit from the authority." The Authority interprets this section to authorize withdrawals of groundwater from the Aquifer during the interim authorization period without a groundwater withdrawal permit. In addition, this section authorizes the Authority to regulate well construction during the interim authorization period.

Section 1.17(a) of the Act provides that a person who, on the effective date of Article 1 of the Act (i.e. June 28, 1996), owns a producing well that withdraws water from the aquifer may continue to withdraw and beneficially use water without waste until final action on permits by the Authority, if: (1) the well is in compliance with all statutes and rules relating to well construction, approval, location, spacing, and operation; and (2) by March 1, 1994,[1] the person files a declaration of historical use on a form as required by the Authority. The Authority interprets this section to provide the basic authority for an existing user to continue to make withdrawals from the Aquifer during the interim authorization period. This section also provides the start date for the interim authorization period.

[1] This March 1, 1994 date was changed by the Texas Supreme Court to December 28, 1996. See Barshop v. Medina Under. Wat. Cons. Dist., 925 S.W.2d 618 (Tex. 1996).

Section 1.17(b) of the Act specifies that use under interim authorization may not exceed on an annual basis the historical, maximum, beneficial use of water without waste during any one calendar year as evidenced by the person's declaration of historical use, unless otherwise provided by the Authority. The Authority interprets this section to place limits on the amount of groundwater that an existing user may annually withdraw from the Aquifer.

Section 1.17(c) of the Act specifies that use under interim authorization is subject to the Authority's comprehensive management plan and rules. The Authority interprets this section to authorize the Authority to issue rules to regulate withdrawals from the Aquifer during the interim authorization period. Additionally, this section authorizes the placing of conditions on the withdrawal of groundwater from the Aquifer during the interim authorization period.

Section 1.17(d) of the Act specifies when use under interim authorization ends for a given well. The Authority interprets this section as defining when the interim authorization period ends.

§711.70. Interim Authorization Groundwater Withdrawal Amounts.

During a well's interim authorization period, a person owning a well qualifying for interim authorization status may withdraw on an annual basis an amount not to exceed the lesser of the following amounts:

(1) the person's historical, maximum beneficial use claimed in §4B of a declaration; or

(2) if the person is an applicant in a contested case hearing that has been pending before SOAH for a period of at least one year, an amount otherwise determined by the Board.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009046

Gregory M. Ellis
General Manager
Edwards Aquifer Authority
Effective date: January 17, 2001
Proposal publication date: September 29, 2000
For further information, please call: (210) 222-2204

♦ ♦ ♦

SUBCHAPTER H. ABANDONMENT AND CANCELLATION

31 TAC §§711.190, 711.192, 711.194, 711.198

The Edwards Aquifer Authority (the "Authority") adopts new 31 TAC §§711.190, 711.192, 711.194 and 711.198 (the "Chapter 711 Subchapter H rules") relating to the Authority's implementation of a Groundwater Withdrawal Permitting Program and the circumstances under which such permits may be abandoned. Sections 711.190, 711.192, 711.194 are adopted with changes to the proposed text as published in the September 29, 2000 issue of the *Texas Register* (25 Tex. Reg. 9886) and are republished herein. Section 711.198 is adopted without changes and will not be republished.

The Authority has elected not to adopt §§711.196, 711.200, 711.202 and 711.204 at this time and hereby withdraws these rules for permanent adoption.

The Edwards Aquifer Authority Act, Act of May 30, 1993, 73rd Legislature, Regular Session, Chapter 626, 1993 Texas General LAWS 2350, as amended by Act of May 28, 1995, 74th Legislature, Regular Session, Chapter 3189, 1995 Texas General LAWS 2505, Act of May 16, 1995, 74th Legislature, Regular Session, Chapter 361, 1995 Texas General LAWS 3280, and Act of May 6, 1999, 76th Legislature, Regular Session, Chapter 163, 1999 Texas General LAWS 634 (the "Act"), requires the Authority to implement a permitting system whereby "existing users" of groundwater from the Edwards Aquifer (the "Aquifer") may apply for and receive initial regular permits issued by the Authority allowing for the withdrawal of groundwater from the Aquifer. The Act imposes a number of restrictions upon withdrawal from the Aquifer after permits are issued. The rules in Subchapter H of Chapter 711, 31 TEXAS ADMINISTRATIVE CODE, are intended to effectuate the components of the Act which deal with abandonment.

The new sections are adopted pursuant to the following statutory provisions contained within the Act.

Section 1.08(a) of the Act provides that the Authority "has all of the powers, rights, and privileges necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer." The Authority interprets this section to provide the Authority with broad and general powers to take actions as necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the Aquifer, including the abandonment of groundwater withdrawal permits.

Section 1.11(a) of the Act provides that the Board of Directors of the Authority (the "Board") "shall adopt rules necessary to carry out the authority's powers and duties under this article (the Act), including rule governing procedures of the board and the authority." The Authority interprets this section to provide broad rulemaking authority to implement the various substantive and procedural programs set forth in the Act related to the Aquifer, including the abandonment of groundwater withdrawal permits.

Section 1.11(b) of the Act requires the Authority to "ensure compliance with permitting, metering, and reporting requirements and . . . regulate permits." The Authority interprets this section, in conjunction with §1.11(a) and (h) of the Act, and section 2001.004(1) of the APA, to require the Authority to adopt and enforce rules related to the abandonment of groundwater withdrawal permits.

Section 1.16(g) of the Act provides that initial regular permits do not have a term and remain in effect, among other things, until abandoned. The Authority interprets this section as authorizing the Authority to issue rules relative to the abandonment of groundwater withdrawal permits.

The Subchapter H Rules

Section 711.190 provides that the purposes of Subchapter H are to establish the criteria under which a groundwater withdrawal permit may be abandoned. The factual basis for this rule is the existence of §1.16(g) of the Act which provides for the abandonment of groundwater withdrawal permits.

Sections 711.192 and 711.194 provide that Subchapter H applies to the abandonment of any groundwater withdrawal permits. Section 711.192 simply clarifies that Subchapter H deals only with the abandonment of groundwater withdrawal permits. No other subject matter related to groundwater withdrawal permits is covered by this subchapter. The factual basis for this rule is the existence of section 1.16(g) of the Act which allows for the abandonment of initial regular permits. Section 711.194 states that all groundwater withdrawal permits issued are subject to abandonment. There are a variety of groundwater withdrawal permits which the Authority may issue: initial regular permits (see Act §1.16), additional regular permits (Act §1.18), term permits (Act §1.19), emergency permits (Act §1.20), recharge recovery permits (Act §§1.08(a) and 1.15(b), among other sections), and monitoring well permits (Act §1.15 (b)). The Authority has determined that there is no basis to distinguish between these types of groundwater withdrawal permits and their susceptibility to abandonment.

Section 711.198 provides that a permit holder may voluntarily enter into an order with the Authority declaring his or her abandonment of groundwater withdrawal permits. The factual basis for this rule is that it is necessary to establish a procedure by which to accomplish an abandonment. An agreed order provides an efficient and effective method to provide a legal basis to modify water accounting and permit records to reflect the abandonment.

Section 2001.0225 of the Texas Government Code requires an agency to perform, under certain circumstances, a regulatory analysis of major environmental rules ("RIAMER"). There are two primary components that must be met before a RIAMER is required. First, no RIAMER need be prepared if the rules in question are not "major environmental rules" or "MERs." Second, even if the rules are MERs, no RIAMER need be prepared if adoption of the MERs would not result in any one of the following criteria listed in section 2001.0225(a)(1)-(4):

1. the MER would "exceed" a standard set by federal law, unless the MER is specifically required by state law;

2. the MER would "exceed" an express requirement of state law, unless the MER is specifically required by federal law;

3. the MER would "exceed" a requirement of a delegation agreement or contract between the state and an agency or representative of the federal governmental to implement a state and federal program; or

4. the MER is adopted solely under the "general powers" of the agency instead of under a specific state law.

The Act requires the Authority to implement a permitting system. At the same time, the Act requires the Authority to close abandoned wells, and to terminate permits which have been abandoned. The Subchapter H rules establish the criteria and procedures under which a declaration of abandonment may be entered by the Board evidencing the owners's present intent to discontinue permanently the withdrawal and beneficial use of all or part of the groundwater under his or her permit.

The Subchapter H rules are an integral part of a conventional water law-based regulatory program. The specific intent of Subchapter H is to encourage the beneficial use of groundwater, avoid speculation, and clear the water accounting records of the Authority to extinguish permits that are not being used. Therefore, the Subchapter H rules do not have the specific intent to "protect the environment" or "reduce risks to human health from environmental exposure" and they are not MERs.

Further, even if any of the Subchapter H rules were MERs, no RIAMER need be prepared because none of the rules meet any of the criteria listed in APA §2001.0225(a)(1)-(4). First, the rules do not exceed a standard set by federal law. The only reasonably related federal law establishes the Sole Source Aquifer Program implemented by the EPA for portions of the Edwards Aquifer. There is no federal law that specifically requires permitting for withdrawals of Edwards Aquifer groundwater or for abandonment of such permits. Therefore, the Subchapter H rules do not exceed a standard set by federal law. Moreover, even if the rules did exceed a standard set by federal law, the rules are specifically required by the Act, a state law which requires the Authority to, among other things: manage, conserve, preserve and protect the aquifer; adopt rules to carry out its powers and duties under the Act; regulate permits, manage withdrawals and points of withdrawals from the aquifer; require various types of permits for certain withdrawals, close abandoned wells, and cancel or retire abandoned or unused permits (pursuant to, *inter alia*, §§1.08(a), 1.11(a), (b), and 1.16(g) of the Act).

Second, the Subchapter H rules do not exceed an express requirement of state law. Instead, the rules are designed to carry out the Authority's statutory responsibility to: manage, conserve, preserve and protect the aquifer, adopt rules to carry out its powers and duties under the Act, to regulate permits, manage withdrawals, from the aquifer, require various types of permits for certain withdrawals, close abandoned wells, and cancel or retire abandoned or unused permits (pursuant to, *inter alia*, §§1.08(a), 1.11(a), (b), and 1.16(g) of the Act). The rules are designed to comply with these express requirements of state law and not exceed them. Other than the Act, there are no other "express requirements of state law" which could be exceeded by these rules.

Third, the Subchapter H rules do not exceed a requirement of a delegation agreement or contract between the State of Texas and an agency or representative of the federal government to implement a state and federal program. The subject matter of the rules is not covered by any delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program.

Fourth, the Subchapter H rules would not be adopted solely under the general powers of the Authority instead of under a specific state law. While these rules are adopted in part under the Authority's general powers, they are also adopted under the Act, a specific state law regarding the Edwards Aquifer. In particular, the rules are adopted pursuant to, *inter alia*, §§1.08(a), 1.11(a), (b), and 1.16(g) of the Act, which require the Authority to, among other things: manage, conserve, preserve and protect the aquifer; adopt rules to carry out its powers and duties under the Act; regulate permits, manage withdrawals and points of withdrawals from the aquifer; require various types of permits for certain withdrawals, close abandoned wells, and cancel or retire abandoned or unused permits.

For these reasons, it is not necessary to perform a RIAMER on the Subchapter H rules.

Five public hearings were held on the Chapter 711 Subchapter H rules and other rules proposed by the Authority on: Monday, October 2, 2000 at 6:00 p.m. at the conference center of the Edwards Aquifer Authority, 1615 N. St. Mary's Street, San Antonio, Texas; Tuesday, October 3, 2000 at 6:00 p.m., at St. Paul's Lutheran Church, 1303 Avenue M, Hondo, Texas; Wednesday, October 4, 2000 at 6:00 p.m., at the San Marcos Activity Center, 501 E. Hopkins, San Marcos, Texas; Wednesday, October 11, 2000 at 6:00 p.m., at the Sgt. Willie DeLeon Civic Center, 300 E. Main Street, Uvalde, Texas; and Thursday, October 12, 2000, at 6:00 p.m., at the New Braunfels Civic Center, 380 S. Seguin Avenue, New Braunfels, Texas.

The public comment period closed on October 30, 2000. Oral and/or written comments were provided by A. M. Rimkus ("Rimkus"), New Braunfels Utilities ("NBU"), Robert Grossenbacher ("Grossenbacher"), Liza Toombs ("Toombs"), Van Hardesty ("Hardesty"), Marvin Verstuyft of R& M Verstuyft Knippa Farms ("Verstuyft Farms"), Mary Troxclair ("M. Troxclair"), Noel Troxclair ("N. Troxclair"), Debbie Ward ("Ward"), Adah McGlothlin ("McGlothlin"), Mr. & Mrs. Eugene Verstuyft ("Verstuyfts"), Ray A. Dabney ("Dabney"), Frances B. "Ed" Stein ("Stein"), E. D. Kincaid, III ("Kincaid"), Bill Clayton ("Clayton"), Knoxie Johnson ("Johnson"), Tommy C. Walker ("Walker"), Judge Bill Mitchell ("Mitchell"), Robert L. and Mary Lou Gibson ("Gibsons"), Kenneth A. Haby ("Haby"), Linda Gilleland ("Gilleland"), Lawrence and Shirley Wilde of Wilde Farms ("Wilde Farms"), Marilyn Owens ("Owens"), John A. Cardwell of Cardwell & Hart ("Cardwell"), Joe R. Straus, Jr. of Straus Medina Ranch ("Straus"), Bickerstaff, Heath, Smiley, Pollan, Kever & McDaniel, L.L.P. on behalf of the Texas Farm Bureau ("TFB"), Janet Ruzza ("Ruzza"), San Antonio Water System ("SAWS"), City of Selma ("Selma"), L.C. Meyer on Behalf of A.M. Rimkus ("Meyer/Rimkus"), Andrew J. Aelvoet on behalf of Southwest Texas Federal Land Bank ("FLB"), Roy Luevano ("Luevano"), Bob Price ("Price"), Ronald J. Freeman on behalf of the Kleburg Family Trusts ("Kleburg Family"), Jimmy Carnes ("Carnes"), Rodney Reagan ("Reagan"), Vaughn Winn ("Winn"), Sammy Gugliotti ("Gugliotti"), Lawrence Friesenhahn ("Friesenhahn"), David Bishop ("Bishop"), Roberto Coleman ("Coleman"), Dietrich Gembler ("Gembler"), John Brigman ("Brigman"), Paul Edwards ("Edwards"), Jeanette Garcia ("Garcia"), Representative Tracy King ("Representative King"), Raphael Pineda ("Pineda"), Joe Ptak ("Ptak"), First State Bank of Uvalde (FSB), Dan Kowal ("Kowal"), Bo Farr ("Farr"), Collin Markt ("Markt"), David Archer for Del Monte Foods ("Del Monte"), and Jerry Bates ("Bates").

Section 711.190

Public Comment:

SAWS believes the proposed cancellation of permitted rights is anti-conservation and would not promote the maximum use of aquifer water, beneficial or otherwise. Therefore, SAWS recommends the rule relating to the purpose of subchapter H be modified to read:

The purpose of this subchapter is to promote the use of groundwater from the aquifer to its maximum benefit and establish the circumstances under which groundwater withdrawal permit may be abandoned.

Authority Response:

While the Authority does not agree with SAWS' comment, the comment is rendered moot in light of the fact that the Authority has decided to withdraw all rules relating to the cancellation of groundwater withdrawal permits at this time. In accordance with this withdrawal, the Authority has modified the rule to read:

The purpose of this subchapter is to establish the circumstances under which a groundwater withdrawal permit may be abandoned.

Section 711.194

Public Comment:

FLB believes the Legislature did not specifically empower the Authority to declare a permit abandoned without the permission of the permittee. Therefore, FLB requests that §711.194 which currently states:

All groundwater withdrawal permits issued shall be subject to cancellation or abandonment be modified to read:

All groundwater withdrawal permits may be cancelled with the consent of the permit holder and any lienholder of the property.

Authority Response:

The Authority does not agree with the comment made by FLB. However, the comment is rendered moot in light of the fact that the Authority has decided to withdraw the rules relating to the involuntary abandonment or cancellation of groundwater withdrawal permits at this time. In accordance with this withdrawal, the Authority has modified the rule to read:

All groundwater withdrawal permits issued shall be subject to abandonment.

Section 711.198

Public Comment:

FLB proposes that section 711.198 be revised to provide that before a declaration of abandonment of a groundwater withdrawal permit is considered by the board, there be prior notice given to any lienholders on that property. It further proposes that before any agreed order for declaration of abandonment of a groundwater withdrawal permit is entered, there be consent of the lienholder before it is accepted by the Authority and before the permit is actually abandoned.

Authority's Response:

The Authority received this comment and disagrees with it. The Authority is not obligated under statutory or common law to provide notice to lienholders of its intent to consider a declaration of abandonment or obtain the consent of lienholders before accepting a declaration of abandonment. It would be unduly burdensome to require the Authority to comply with such a rule. Because a voluntary abandonment requires board action, consideration of a declaration will be listed on the notices of meetings posted by the Authority. Any lienholder can review these notices on a regular basis to determine if a declaration is being considered. The lienholder may attend the meeting and present comments to the board before it makes a decision on the declaration. In light of this discussion, section 711.198 has not been modified.

Section 711.202

Public Comment:

FLB comments that the rule should be revised to provide that any unrestricted groundwater under an initial regular permit for irrigation purposes that is leased to a municipal or industrial user, is a beneficial use and, therefore, exempt from cancellation under subsection (a). FLB also proposes the addition of a new subsection to 711.202 that would read as follows:

(c) A groundwater withdrawal permit for irrigation use is exempt from cancellation under subsection (a) of this section if the water has not been withdrawn and put to beneficial use at any time during the ten year period immediately preceding the cancellation proceedings authorized by this subchapter if such nonuse is due to rainfall, other environmental conditions, or reasonable business or economic decisions made by the permit holder.

NBU also suggests that the Authority provide a waiver or exemption for municipalities with a dual water supply.

Authority's Response:

While the Authority does not agree with the comments, the comments are rendered moot in light of the fact that the Authority has decided to withdraw section 711.202 relating to cancellation of groundwater withdrawal permits at this time.

Sections 711.196, 711.200,711.202, 711.204

Subchapter H has been informally referred to as the "use it or lose it" rules. These rules include sections 711.196 and 711.202 which deal with the abandonment and cancellation of groundwater withdrawal permits based on nonuse, and sections 711.200 and 711.204 that relate to the initiation of proceedings by the general manger for abandonment and cancellation. The comments received by the Authority referred to this group of rules in several ways. Many commenters referred to them as the "use it or lose it" rules, while others referred to the "subchapter H" rules. Still others named the specific rule. For clarity, the Authority has organized these comments together and responds as follows.

Public Comments:

Representative King, Bates, Verstuyfts, Luevano, Coleman, Brigman, and Carnes generally oppose these rules.

Ptak comments that section 711.196 should place more emphasis on the abandonment of claims based on aquifer water not being used in the permitted manner but rather being squandered or hidden. Ptak proposes the rule be modified to include a provision that if water is not used for its stated use, then the right to the water is abandoned.

Hardesty, Kincaid, Clayton, Johnson, Grossenbacher, Rimkus, M. Troxclair, McGlothlin, Dabney, Wilde Farms, Cardwell, Pineda, Gugliotti, Toombs, Farr, Kleburg Family, N. Troxclair, and Meyer/Rimkus assert that subchapter H violates property rights or will negatively impact property values.

Verstuyft Farms, TFB, Gilleland, Gugliotti, Reagan, Kowal, Toombs, Farr, FLB, Markt, Kleburg Family, and Hardesty comment that the proposed rules exceed the power granted to the Authority and/or general manager by the Act.

SAWS, Wilde Farms, Straus, Toombs, Ward, Verstuyft Farms, Kincaid, Johnson, Walker, Hardesty, Price, Garcia, Friesenhahn, Winn, Bishop, Del Monte, Gembler, Owens, and FLB comment that the rules do not favor conservation but instead encourage waste.

N. Troxclair and Edwards comment on the Notice of Proposed Rule which studies the effects of the rules for the next five years. They believe it is not appropriate to examine only five years when the rules provide ten year time periods.

Mitchell comments that larger cities in the region are taking too much water from smaller cities. He states the rules are not the answer to water management matters.

Haby urges the Authority to consider factors such as health and weather conditions in regards to an irrigator's inability to use his permit limit.

Hardesty, Toombs and Verstuyft Farms argue that nonuse is not "waste."

FSB, Stein, Luevano, Ruzza, and the Gibsons comment that the rules do not show enough concern for the agricultural industry and will injure the ranching and farming industries.

Cardwell, Toombs, Selma, NBU, Markt, TFB, and Straus state the provisions are vague, require clarification, and/or may be arbitrarily enforced.

SAWS comments that it is inappropriate for the Authority to adopt rules that provide for involuntary abandonment or cancellation of rights. SAWS comments that abandonment of a right can only occur though a voluntary action by the owner of water rights and proposes the elimination of these rules. In addition, SAWS proposes the striking of all references to "cancellation" in subchapter H.

Authority's Response:

The Authority has received the above-referenced comments. While the Authority does not agree with the comments, the comments are rendered moot in light of the fact that the Authority has decided to withdraw all rules relating to the involuntary abandonment and cancellation of groundwater withdrawal permits (sections 711.196, 711.200, 711.202 and 711.204).

General

Public Comment:

TFB maintains that a takings impact statement ("TIA") was required before the Authority provided public notice of the proposed rules. According to TFB, the Texas Private Real Property Rights Preservation Act ("Property Rights Act") does not excuse the Authority from the requirements of the Property Right Act because the rights are not "vested" or because the Legislature has chosen to regulate those property rights. Furthermore, the TFB contends that property does not have to be vested to come within the purview of the Property Rights Act and, nonetheless, groundwater rights are vested rights requiring no perfection because they accompany the surface estate.

Authority's Response:

The Authority has received this comment and disagrees with it. Chapter 2007 of the Texas Government Code, the Property Rights Act referred to by the TFB, requires governmental entities, under certain circumstances, to prepare a TIA in connection with certain covered categories of proposed governmental actions. Based on the following reasons, the Authority has determined that it need not prepare a TIA in connection with the adoption of these rules.

First, the Authority has made a "categorical determination" that rules dealing with the abandonment of groundwater withdrawal permits issued by the Authority do not affect "private real property" as that term is defined in the Texas Private Real Property Rights Preservation Act. The Subchapter H rules delineate when groundwater withdrawal permits issued by the Authority may be abandoned. The withdrawal permits issued by the Authority derive not from the common law, but from a statute - the Act. Thus, they are not an "interest in real property recognized by common law," and the loss of such a permit does not affect private real property.

Second, the Authority's action in adopting these rules is an action that is reasonably taken to fulfill an obligation mandated by state law and is thus excluded from the Texas Private Real Property Rights Preservation Act under Section 2007.003(b)(4) of the Texas Government Code. See §§1.08(a), 1.11(a), (b), and 1.16(g) of the Act.

This conclusion is supported by the decision in *Edwards Aquifer Authority v. Bragg*, 21 S.W.3d 375 (Tex. App.-San Antonio 2000, pet. filed)("*EAA v. Bragg*"). In that case, the Plaintiffs sued to invalidate a set of rules adopted by the Authority (the "prior rules") which were designed to implement the Authority's permitting program. The Fourth Court of Appeals held that the Authority's adoption of its prior permitting rules was expressly mandated by the Act and was therefore excepted from the operation of the Texas Private Real Property Rights Preservation Act. *Id.* at 379-80. The holding in that case is relevant here.

Third, it is the position of the Authority that all valid actions of the Authority are excluded from the Texas Private Real Property Rights Preservation Act under Section 2007.003(b)(11)(C) of the Texas Government Code as actions of a political subdivision taken under its statutory authority to prevent waste or protect the rights of owners of interest in groundwater.

Accordingly, for the reasons stated above, a TIA need not be performed in connection with the adoption of these rules.

The new sections are adopted pursuant to the following statutory provisions contained within the Act.

Section 1.08(a) of the Act provides that the Authority "has all of the powers, rights, and privileges necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer." The Authority interprets this section to provide the Authority with broad and general powers to take actions as necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the Aquifer, including the abandonment of groundwater withdrawal permits.

Section 1.11(a) of the Act provides that the Board of Directors of the Authority (the "Board") "shall adopt rules necessary to carry out the authority's powers and duties under this article (the Act), including rule governing procedures of the board and the authority." The Authority interprets this section to provide broad rulemaking authority to implement the various substantive and procedural programs set forth in the Act related to the Aquifer, including the abandonment of groundwater withdrawal permits.

Section 1.11(b) of the Act requires the Authority to "ensure compliance with permitting, metering, and reporting requirements and . . . regulate permits." The Authority interprets this section, in conjunction with §1.11(a) and (h) of the Act, and §2001.004(1) of the APA, to require the Authority to adopt and enforce rules related to the abandonment of groundwater withdrawal permits.

Section 1.16(g) of the Act provides that initial regular permits do not have a term and remain in effect, among other things, until abandoned. The Authority interprets this section as authorizing the Authority to issue rules relative to the abandonment of groundwater withdrawal permits.

§711.190. Purpose.

The purpose of this subchapter is to establish the circumstances under which a groundwater withdrawal permit may be abandoned.

§711.192. Applicability.

This subchapter applies to the abandonment of any groundwater withdrawal permits.

§711.194. Permit Condition.

All groundwater withdrawal permits issued shall be subject to abandonment.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009048
Gregory M. Ellis
General Manager
Edwards Aquifer Authority
Effective date: January 17, 2001
Proposal publication date: September 29, 2000
For further information, please call: (210) 222-2204

♦ ♦ ♦

SUBCHAPTER K. ADDITIONAL GROUNDWATER SUPPLIES

31 TAC §§711.290, 711.292, 711.294, 711.296, 711.298, 711.300, 711.302, 711.304

The Edwards Aquifer Authority (the "Authority") adopts new 31 TAC §§ 711.290, 711.292, 711.294, 711.296, 711.298, 711.300, 711.302, and 711.304 (the "Chapter 711 Subchapter K rules") relating to the procedures for the Authority's governing board to utilize when determining whether to raise the "cap" governing how much water can be withdrawn from the Edwards Aquifer pursuant to certain permits issued by the Authority. Sections 711.292, 711.294, 711.302, 711.304 are adopted with changes to the proposed text as published in the September 29, 2000 issue of the *Texas Register* (25 TexReg 9892) and are republished herein. Sections 711.290, 711.296, 711.298, 711.300 are adopted without changes and will not be republished.

The Edwards Aquifer Authority Act, Act of May 30, 1993, 73rd Legislature, Regular Session, Chapter 626, 1993 TEXAS GENERAL LAWS 2350, as amended by Act of May 28, 1995, 74th Legislature, Regular Session, Chapter 3189, 1995 TEXAS GENERAL LAWS 2505, Act of May 16, 1995, 74th Legislature, Regular Session, Chapter 361, 1995 TEXAS GENERAL LAWS 3280, and Act of May 6, 1999, 76th Legislature, Regular Session, Chapter 163, 1999 TEXAS GENERAL LAWS 634 (the "Act"), requires the Authority to implement a permitting system whereby "existing users" of groundwater from the Edwards Aquifer and other potential users of aquifer water may apply for and receive permits issued by the Authority allowing for the withdrawal of groundwater from the aquifer. The Act also mandates two withdrawal "caps." Initially, total permitted withdrawals for initial and additional regular permits may not exceed 450,000 acre-feet per year and, after January 1, 2008, total permitted withdrawals may not exceed 400,000 acre-feet per year. However, the Act also provides a mechanism whereby the Authority may, under appropriate circumstances, increase these 450,000 and 400,000 acre-feet withdrawal caps. The Act empowers the Authority to, at its discretion and under limited circumstances, increase these caps if, through studies, implementation of water management strategies, consultation with other federal and state agencies, and so on, the Authority determines that such an increase is warranted. Sections 711.290-711.304, the Chapter 711 Subchapter K rules, set out in more detail the criteria for and procedures by which the Authority may raise these withdrawal caps.

The new sections are adopted pursuant to the following statutory provisions contained within the Act.

Section 1.08(a) of the Act provides that the Authority "has all of the powers, rights, and privileges necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer." This section provides the Authority with broad and general powers to take actions as necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer. The rules further those objectives.

Section 1.11(a) of the Act provides that the Board of Directors of the Authority (the "Board") "shall adopt rules necessary to carry out the authority's powers and duties under this article (the Act), including rule governing procedures of the board and the authority." This section provides broad rulemaking authority to implement the various substantive and procedural programs set forth in the Act related to the Edwards Aquifer, including the permitting program.

Section 1.11(b) of the Act requires the Authority to "ensure compliance with permitting, metering, and reporting requirements and . . . regulate permits." This section, in conjunction with §1.11(a) and (h) of the Act, and §2001.004(1) of the APA, requires the Authority to adopt and enforce the Chapter 711 rules.

Section 1.11(h) of the Act provides, among other things, that the Authority is "subject to" the Administrative Procedure Act (the "APA"). This section essentially provides that the Authority is required to comply with the APA for its rulemaking, even though the Authority is a political subdivision and not a state agency, and therefore, would typically not be subject to APA requirements. Section 2001.004(1) of the APA requires agencies subject to the APA to "adopt rules of practice stating the nature and requirements of all available formal and informal procedures."

Section 1.14(a) of the Act provides that authorizations to withdraw aquifer water shall be limited in order to: protect water quality of the aquifer and surface streams to which the aquifer contributes springflow; achieve water conservation; maximize beneficial use of water from the aquifer; protect aquatic and wildlife habitat as well as federally or state-designated threatened or endangered species; and provide for instream uses, bays and estuaries.

Section 1.14(b) of the Act imposes, subject to certain limitations, an initial aquifer withdrawal "cap" for permitted withdrawals of 450,000 acre-feet per year, until December 31, 2007. The Chapter 711 Subchapter K rules explain how this cap may, under appropriate circumstances, be raised by the Authority, and other procedural details.

Section 1.14(c) of the Act imposes, subject to certain limitations, an aquifer withdrawal "cap" for permitted withdrawals of 400,000 acre-feet per year, beginning January 1, 2008. The Chapter 711 Subchapter K rules explain how this cap may, under appropriate circumstances, be raised by the Authority, and other procedural details.

Section 1.14(d) of the Act provides that either of the caps listed above may be raised by the Authority if, through studies and implementation of certain strategies, the Authority, in consultation with state and federal agencies, determines the caps may be raised. Subchapter K sets out this process.

Section 1.15(a) of the Act directs the Authority to manage withdrawals from the aquifer and manage all withdrawal points from the aquifer as provided by the Act. This section is implemented, in part, through the Chapter 711 Subchapter K rules.

Section 1.44 of the Act allows the Authority to enter into cooperative contracts with other political subdivisions for artificial recharge projects and for possible additional withdrawals as a result of those projects. The section further provides, however, that such withdrawals are not subject to the withdrawal caps.

The Subchapter K Rules

Section 711.290 provides that the purpose of Subchapter K is to establish the procedures by which the board may determine whether there are additional groundwater supplies available to warrant raising the withdrawal caps. This purpose is derived from §1.14(d) of the Act and requires no further elaboration.

As originally proposed, §711.292 provided that the Subchapter K rules apply only to initial regular permits, additional regular permits, and recharge recovery permits. The Authority has revised this rule and now adopts it in modified form which states that the Subchapter K rules apply only to initial regular permits and additional regular permits. This change is needed to conform with the Authority's conclusion that only initial and additional regular permits are subject to the statutory withdrawal caps.

There are a variety of groundwater withdrawal permits which the Authority may issue: initial regular permits (*see* Act §1.16), additional regular permits (Act §1.18), term permits (Act §1.19), emergency permits (Act §1.20), recharge recovery permits (Act §§1.08(a), 1.14(a), 1.15(a) and TEXAS WATER CODE, §36.113), and monitoring well permits (Act §§1.15(a) and (b)). The Authority, however, has determined that the "caps" in §1.14(b) and (c) are applicable only to initial and additional regular permits.

A review of §1.14(d) of the Act, which grants the Authority the discretion to raise the cap under appropriate circumstances, shows that the section may only apply to initial and additional regular permits. Section 1.14(b) and (c) of the Act, respectively, provide that the amounts of groundwater available for permitting are 450,000 acre-feet per year through December 31, 2007, and 400,000 acre-fee per year thereafter, unless either of the caps is increased by the Authority pursuant to §1.14(d). Section 1.14(b) and (c) do not specifically identify the groundwater withdrawal permits to which the "caps" apply. Those sections do not state that the caps apply to all permits. However, a review of the Act as a whole shows that the "caps" can logically only apply to initial and additional regular permits. In this analysis, it is important to consider the import of §§1.16(e), 1.18(a), 1.19, 1.20, 1.21(a) and 1.44(d) of the Act. The "cap" is made applicable to initial regular permits by §1.16(e) where it provide that, "to the extent water is available for permitting," certain permit amounts should be recognized and certain proportional adjustment procedures may need to be invoked. Section 1.16 addresses exclusively the issuance of initial regular permits. Section 1.18(a) provides that "to the extent water is available for permitting after the issuance of permits to existing users" (i.e. initial regular permits), then the Authority may issue additional regular permits.

On the other hand, neither §1.19 nor §1.20, relating to term and emergency permits, respectively, contain language such as "to the extent water is available for permitting" which would suggest an intent to subject those types of permits to the caps. Further, term and emergency permits are subjected to their own, independent limiting factors. Section 1.19 of the Act provides for interruption of withdrawals under term permits based on the triggering of certain index well water levels. Because of this interruptibility feature of term permits at higher aquifer levels (than initial and additional regular permits might otherwise be subject to) it is unnecessary to apply the caps in §1.14(b) and (c) to term permits. Section 1.20(d) specifically provides that withdrawals under emergency permits may be made "without regard to its effect on other permit holders." The Authority interprets this provision to mean that the issuance of emergency permits does not affect the permit allocation process under §1.14(b) and (c), the proportional adjustment process under §1.16(e), or the equal percentage reduction process under §1.21(c). Further, the strict criteria set forth in §1.20 for when emergency permits may be issued ("to prevent the loss of life or to prevent severe, imminent threats to the public health or safety") would be undermined if such permits were subject to the caps. If, for example, emergency permits were subject to the caps, then the Authority might be unable to issue such a permit to a given applicant (because the cap had already been achieved) even though the applicant needed the permit to prevent the loss of life. The Authority believes that such an outcome would be contrary to the legislative intent. Section 1.21(a) and (c) also reinforce the conclusion that the "caps" do not apply to term or emergency permits. Under subsection (a), the Authority is to prepare a plan to reduce withdrawal "under regular permits" to meet the cap. Similarly, subsection (c) establishes the process to reduce withdrawals "under regular permits" to reduce "each regular permit" to meet the cap.

The Authority has also concluded that the "caps" do not apply to monitoring well permits. Because of the nature and duration of withdrawals under monitoring well permits (i.e. generally low withdrawal amounts on an intermittent basis), there is little likelihood that these withdrawals will materially affect the water supply that will be available to the holders of regular permits. Moreover, monitoring well permit withdrawals are not likely to affect the performance of the Authority's other aquifer management programs. At the same time, it is critical that groundwater withdrawals necessary to perform monitoring well functions are available in sufficient quantities. Monitoring of the aquifer is critical to the long-term maintenance of the viability of the aquifer and the Authority's ability to manage the aquifer. Therefore, the Authority has determined that monitoring activities should not be constrained or made more difficult by the caps applied to other types of permits. Further, if monitoring wells were subject to the cap, then it could hinder the ability to monitor the ongoing well-being of the aquifer. If, for example, monitoring well permits were subject to the caps, then the Authority might be unable to issue such a permit to a given applicant (because the cap had already been achieved) even though the applicant (such as the TNRCC) needed the permit to investigate a potential case of contamination of the aquifer. The Authority believes that such an outcome would be contrary to the legislative intent.

Finally, the Authority does not generally believe that recharge recovery permits are subject to the caps. Section 1.44 of the Act empowers the Authority to authorize, under appropriate circumstances, political subdivisions to provide artificial recharge of the aquifer for the subsequent retrieval of the recharged water by the political subdivision. Such withdrawals, however, are expressly exempted from the withdrawal caps by §1.44(d). For these reasons, §711.292, as adopted, provides that the subchapter applies only to initial and additional regular permits.

Section 711.294 identifies water management strategies which, if implemented, may potentially provide a basis for increasing the withdrawal caps, including springflow augmentation, surface water diversions of the Guadalupe River downstream of Comal and San Marcos Springs, supplemental recharge of the aquifer, conjunctive management of surface and groundwater, and other water management strategies. These strategies are derived primarily directly from §§1.14(d) and 1.30 of the Act and require little elaboration. As originally proposed, there was a §711.294(b) which identified certain water management strategies that, if implemented, would arguably not provide a basis for increasing the caps -- conservation, reuse, and drought management plans. In response to public comments, and as discussed more below, the Authority has revised this rule and now adopts it in modified form which deletes subsection (b).

Section 711.296 requires the general manager to annually prepare and submit a report to the board identifying all ongoing or completed studies or implemented water management strategies related to the management and availability of water supplies from the aquifer. The section lists the items that must be included in the report, which includes a statement of the purpose of each study or strategy, a recommendation as to whether the study or strategy provides a technical basis to determine that additional supplies are available in the aquifer to warrant raising the cap, a recommendation as to the specific amount of additional groundwater, if any, available from the aquifer, and so on. The purpose of this requirement is to ensure that, when the board considers whether to raise the cap, it has before it the appropriate and relevant data. The rule is also intended to impart predictability and transparency to the decision-making process.

Section 711.298 identifies the procedures and criteria by which the board may issue an order determining that there is sufficient additional water to warrant raising the cap. Generally, the rule provides that the board may issue such an order if, after reviewing the general manager's report required by §711.196, it finds that sufficient studies and/or water management strategies have been completed or implemented, and the general manager's report demonstrates that additional supplies are present in the aquifer and may be withdrawn. These requirements are intended to ensure that the criteria set forth in §1.1.4(d) of the Act are met.

Section 711.300 mandates that, once a board order is issued pursuant to §711.298, the general manager must consult with appropriate state and federal agencies regarding the environmental impacts of increasing the cap, and prepare a report to the board summarizing the results of that consultation. This section is intended to formalize the consultation requirement found in §1.14(d) of the Act.

Section 711.302 identifies the criteria under which the board may issue an order increasing the cap. It may do so if: the board has issued an order determining that additional water supplies are available as required by §711.298; consultations have taken place with appropriate state and federal agencies; and the withdrawal of additional water from the aquifer will not adversely affect the aquifer's water quality, reduce key springflows to levels prohibited by applicable federal or state law, or interfere with the rights of initial regular permittees. The wording of §711.302(4) has been slightly revised to correct a typographical error by adding the word "Springs" after San Marcos. This rule is intended to ensure that the criteria set forth in §1.14(d) of the Act are met before the caps are raised.

Further, the Authority has obligations to limit withdrawals from the aquifer in order to: (1) protect the quality of water in the aquifer (Act §1.14(1)); (2) protect species that are designated as threatened or endangered under applicable federal or state law (Act §1.14(6)); and (3) protect the rights of holders of initial regular permits (*see* Act §§1.14(e), 1.16; *Barshop v. Medina County Underground Water Cons. Dist*., 925 S.W.2d 618, 624, 629, and 632 (Tex. 1996)). Section 711.302 is designed to ensure those duties will continue to be met if additional groundwater supplies are determined to be available.

In the event that the Board finds that there are additional groundwater supplies, and raises the caps accordingly, then §711.304 provides the methodology by which the additional groundwater may be allocated among aquifer users. This rule has been amended from the language as it was originally proposed in order to conform with the Authority's conclusion that only initial and additional regular permits are subject to the statutory withdrawal caps, and in order to ensure the consistent use of terminology throughout the Authority's rules.

As originally proposed, §711.304(1) provided that if the additional water is attributable to certain recharge and storage permits, then the additional groundwater will be allocated to the holder of the recharge recovery permit associated with the project. This provision has been deleted from the rule as adopted in order to conform with the Authority's conclusion, discussed more fully above, that only initial and additional regular permits are subject to the statutory withdrawal caps. The deletion of this subsection necessitated the renumbering of the remaining two paragraphs as (1) and (2).

As adopted, §711.304(1) provides that if the additional groundwater is attributable to water management strategies which are paid for by one or more entities other than the Authority, then the additional water will be allocated to the entity or entities paying for the strategy. Pursuant to §711.304(2), any additional water supplies which derive from projects paid for by the Authority will be allocated to restore, on a pro rata basis, any reductions from an applicant's maximum historical use, with first priority going to retirements of initial regular permits made pursuant to §1.21(c) of the Act and second priority going to any permit amounts proportionately adjusted pursuant to §711.172(g)(5) of the Authority's Chapter 711 rules. For example, if the Authority funds a project which results in additional water supplies becoming available and the cap being raised, then that additional water will be proportionally divided among initial regular permit holders to first restore, to the extent possible, permit retirements necessitated by §1.21(c) of the Act which mandates equal percentage reductions in order to achieve the reduction from the 450,000 acre-feet cap to the 400,000 acre-feet cap. Any remaining supplies will be used to restore the permit reductions mandated by §1.16(e) of the Act as implemented by §711.172 of the Authority's permitting rules.

The wording in §711.304(2) originally stated that the additional water will be used to restore reductions from any "applicant's" maximum historical use. However, the wording in the rule as adopted has been changed from "applicant's" to "initial regular permittee's." This change is intended to correct a typographical error in the rule as proposed. The proportional adjustment and equal percentage reduction processes have no effect until permits are issued. Thus, in order to avoid confusion, the change has been made to clarify that one must be an actual permit holder, not merely an applicant, before one can share in any restoration of permit amounts.

Section 711.304(2)(B) originally referenced the restoration of proportionally adjusted amounts under "§711.172(g)(5)." The Authority recently adopted §711.172 as a final rule. In doing so, it revised the text of that rule. Thus, the reference in §711.304(2)(B) necessitated updating. The reference is now to "§711.172(h)."

Section 2001.0225 of the Texas Government Code requires an agency to perform, under certain circumstances, a regulatory analysis of major environmental rules ("RIAMER"). There are two primary components that must be met before a RIAMER is required. First, no RIAMER need be prepared if the rules in question are not "major environmental rules" or "MERs." Second, even if the rules are MERs, no RIAMER need be prepared if adoption of the MERs would not result in any one of the following criteria listed in §2001.0225(a)(1)-(4):

1. the MER would "exceed" a standard set by federal law, unless the MER is specifically required by state law;

2. the MER would "exceed" an express requirement of state law, unless the MER is specifically required by federal law;

3. the MER would "exceed" a requirement of a delegation agreement or contract between the state and an agency or representative of the federal governmental to implement a state and federal program; or

4. the MER is adopted solely under the "general powers" of the agency instead of under a specific state law.

The Act requires the Authority to implement a permitting system. The Act also mandates that, initially, total permitted withdrawals may not exceed 450,000 acre-feet per year and, after January 1, 2008, total permitted withdrawals may not exceed 400,000 acre-feet per year. However, the Act provides a mechanism whereby the Authority may, under appropriate circumstances, increase these 450,000 and 400,000 acre-feet withdrawal caps. The Chapter 711 Subchapter K rules set out in more detail the criteria for and procedures by which the Authority may raise these withdrawal caps. The Authority has determined that these rules have the specific intent to protect the environment and, therefore, might constitute MERs if the other criteria set out in the definition of a MER in §2001.0225(g)(3) are satisfied.

However, without determining whether the Chapter 711 Subchapter K rules constitute MERs, the Authority has concluded that no RIAMER need be prepared for any of the Subchapter K rules because none of them meet any of the criteria listed in APA §2001.0225(a)(1)-(4). First, the rules in Subchapter K do not exceed a standard set by federal law. The only reasonably related federal law establishes the Sole Source Aquifer Program implemented by the EPA for portions of the Edwards Aquifer. There is no federal law that specifically requires permitting for withdrawals of Edwards Aquifer groundwater, permitting withdrawals caps, or methods to raise such permitting withdrawal caps. Therefore, the Subchapter K rules do not exceed a standard set by federal law. Moreover, even if the rules did exceed a standard set by federal law, the rules are specifically required by the Act, a state law which requires the Authority to, among other things: manage, conserve, preserve and protect the aquifer; adopt rules to carry out its powers and duties under the Act; regulate permits, manage withdrawals and points of withdrawals from the aquifer; require various types of permits for certain withdrawals; limit permitted withdrawals in accordance with the 450,000 and 400,000 acre-feet caps, and raise the caps under certain circumstances (pursuant to, *inter alia*, §§1.08(a), 1.11(a), (b) and (h), 1.14(a), (b), (c) and (d), and 1.15(a) of the Act).

Second, the Subchapter K rules do not exceed an express requirement of state law. Instead, the rules are designed to carry out the Authority's statutory responsibility to: manage, conserve, preserve and protect the aquifer, adopt rules to carry out its powers and duties under the Act, to regulate permits, manage withdrawals and points of withdrawals from the aquifer, require various types of permits for certain withdrawals, limit permitted withdrawals in accordance with the 450,000 and 400,000 acre-feet caps, and raise the caps under certain circumstances (pursuant to, *inter alia*, §§1.08(a), 1.11(a), (b) and (h), 1.14(a), (b), (c) and (d), and 1.15(a) of the Act). The rules are designed to comply with these express requirements of state law and not exceed them. Other than the Act, there are no other "express requirements of state law" which are applicable to these rules or which could be exceeded by these rules.

Third, the Subchapter K rules do not exceed a requirement of a delegation agreement or contract between the State of Texas and an agency or representative of the federal government to implement a state and federal program. The subject matter of the rules is not covered by any delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program.

Fourth, the Subchapter K rules would not be adopted solely under the general powers of the Authority instead of under a specific state law. While these rules are adopted in part under the Authority's general powers, they are also adopted under the Act, a specific state law regarding the Edwards Aquifer. In particular, the rules are adopted pursuant to, *inter alia*, §§1.08(a), 1.11(a), (b) and (h), 1.14(a), (b), (c) and (d), and 1.15(a) of the Act, which require the Authority to, among other things: manage, conserve, preserve and protect the aquifer; adopt rules to carry out its powers and duties under the Act; regulate permits, manage withdrawals and points of withdrawals from the aquifer; require various types of permits for certain withdrawals; limit permitted withdrawals in accordance with the 450,000 and 400,000 acre-feet caps, and raise the caps under certain circumstances.

For these reasons, it is not necessary to perform a RIAMER on the Subchapter K rules.

Five public hearings were held on the Chapter 711 Subchapter K rules and other rules proposed by the Authority on: Monday, October 2, 2000 at 6:00 p.m. at the conference center of the Edwards Aquifer Authority, 1615 N. St. Mary's Street, San Antonio, Texas; Tuesday, October 3, 2000 at 6:00 p.m., at St. Paul's Lutheran Church, 1303 Avenue M, Hondo, Texas; Wednesday, October 4, 2000 at 6:00 p.m., at the San Marcos Activity Center, 501 E. Hopkins, San Marcos, Texas; Wednesday, October 11, 2000 at 6:00 p.m., at the Sgt. Willie DeLeon Civic Center, 300 E. Main Street, Uvalde, Texas; and Thursday, October 12, 2000, at 6:00 p.m., at the New Braunfels Civic Center, 380 S. Seguin Avenue, New Braunfels, Texas.

The public comment period closed on October 30, 2000. Oral and/or written comments specifically on the Chapter 711 Subchapter K rules were provided by only one entity, San Antonio Water System ("SAWS"). Additional comments, which were more general in nature, were also received from other parties.

While the commenters generally did not express support or opposition to adoption of the Subchapter K Rules as a whole, they did, as discussed more fully below, suggest changes to and/or opposition to certain portions of the rules.

Section 711. 294

Public Comment:

SAWS suggests the deletion of §711.294(b), which. in the rule as proposed, identified certain water management strategies that the Authority has determined could not provide a basis for increasing the caps. SAWS asserts that §711.294 should speak only to water strategies that might be expected to provide additional groundwater supplies. According to SAWS, if the rules do not explicitly identify management strategies not presently expected to supply additional water, greater flexibility will result and future revisions to the rules might be avoided.

Authority Response:

The Authority agrees with this comment and has deleted subsection (b) in the rule as adopted. The Authority agrees that it is not necessary, at this time, to rule out potential water management strategies, and that it is preferable to maintain flexibility in considering such strategies in the future. Toward that end, the Authority has expanded the list of potential strategies that might provide a basis for raising the cap.

Section 711.300 and §711.302

Public Comment:

SAWS commented on §§711.300 and 711.302 concurrently. SAWS asserts that the Authority need not consult with either state or federal authorities when examining whether to raise the withdrawal caps. Therefore, SAWS seeks the total elimination of §711.300 and seeks changes to §711.302 as shown below:

Based on the general manager's additional water supply the board...

Also, SAWS requests the deletion of §711.302(2).

Authority Response:

The Authority staff received this comment and disagree with it. Section 1.14(d) explicitly requires that, if the Authority determines to raise the caps, it may do so only "in consultation with appropriate state and federal agencies." Thus, the Authority believes it is requires to engage in such consultations prior to raising the caps, and the Authority declines to revise the rules in response to these comments.

Public Comment:

SAWS asserts that neither federal nor state law establishes springflow levels for either the Comal or San Marcos Springs. Instead of an existing statute on this subject, SAWS asserts that a court would establish any such springflow restrictions. As a result, SAWS suggests the following change to §711.302(4):

(4) withdrawal of the additional groundwater supplies will not reduce springflows at Comal or San Marcos Springs; and

Authority Response:

The Authority declines to revise the rule in response to this comment. Pursuant to §1.14(6) of the Act, the Authority has a duty to limit aquifer withdrawals in order to "protect species listed as threatened or endangered under applicable federal or state law." There is much debate over whether state or federal law currently establishes, or in the future might establish, a springflow requirement in order to protect threatened or endangered species. Rule 711.302(4) does not attempt to settle that debate. Instead, it merely clarifies that *if* such a springflow requirement is applicable, then the cap cannot be raised if in doing so, those springflow requirements will not be met. This rule is consistent with the Authority's duty to protect threatened and endangered species dependent upon the springflows, as well as other statutory mandates of the Authority.

Comments on the Rules Generally

Public Comment:

The Texas Farm Bureau ("TFB") maintains that a takings impact statement ("TIA") was required before the Authority provided public notice of the proposed rules. According to TFB, the Texas Private Real Property Rights Preservation Act ("Property Rights Act") does not excuse the Authority from the requirements of the Property Right Act because the rights are not "vested" or because the Legislature has chosen to regulate those property rights. Furthermore, the TFB contends that property does not have to be vested to come within the purview of the Property Rights Act and, nonetheless, groundwater rights are vested rights requiring no perfection because they accompany the surface estate.

Authority Response:

The Authority has received this comment and disagrees with it. Chapter 2007 of the Texas Government Code, the Property Rights Act referred to by the TFB, requires governmental entities, under certain circumstances, to prepare a TIA in connection with certain covered categories of proposed governmental actions. Based on the following reasons, the Authority has determined that it need not prepare a TIA in connection with the adoption of these rules.

First, the Authority has made a "categorical determination" that these rules do not affect private real property in a way that "may result in a taking." The Texas Private Real Property Rights Preservation Act makes it clear that a TIA need only be performed when the proposed governmental action is one that "may result in a taking." *See id.*, §§2007.043(a), 2007.041(a), 2007.042(a). If an action is one that has no potential to result in a taking, then no TIA need be performed.

Adoption of the rules at issue here is not an action that "may result in a taking." The Act requires the Authority to implement a permitting system whereby existing users and other potential users of aquifer water may apply for and receive permits issued by the Authority allowing for the withdrawal of groundwater from the aquifer. The Act also limits the total amount of water which can be withdrawn pursuant to these permits by imposing two "caps" which permitted withdrawals may not exceed in any one year. The rules at issue here implement a process by which the caps may be raised, thereby making *more* water accessible to permit holders. The Authority believes, therefore, that the passage of these rules will not result in a taking.

Second, the Authority's action in adopting these rules is an action that is reasonably taken to fulfill an obligation mandated by state law and is thus excluded from the Property Rights Act under §2007.003(b)(4) of the Texas Government Code. *See* §§1.08(a), 1.11(a), (b), and (h), 1.14(a), (b), (c), and (d), and 1.15(a) of the Act. This conclusion is supported by the decision in *Edwards Aquifer Authority v. Bragg*, 21 S.W.3d 375 (Tex. App.-San Antonio 2000, pet. denied) ("*EAA v. Bragg*"). In that case, the Plaintiffs sued to invalidate a set of rules adopted by the Authority (the "prior rules") which were designed to implement the Authority's permitting program. The Fourth Court of Appeals held that the Authority's adoption of its prior rules was expressly mandated by the Act and was therefore excepted from the operation of Property Rights Act.

Third, it is the position of the Authority that all valid actions of the Authority are excluded from the Property Rights Act under §2007.003(b)(11)(C) of the Texas Government Code as actions of a political subdivision taken under its statutory authority to prevent waste or protect the rights of owners of interest in groundwater. Accordingly, a TIA need not be prepared in connection with the adoption of these rules.

Accordingly, for the reasons stated above, a TIA need not be performed in connection with the adoption of these rules.

Public Comment:

Lightning Oil urges the Authority to engage in seismic exploration program, before making any decisions, in order to provide a more accurate picture of the aquifer. The commenter contends the following organizations/institutions could plan and manage the program: municipalities, county and state government, the Authority, San Antonio Water System ("SAWS"), SARA, major oil companies, and private foundations.

Authority Response:

The Authority has reviewed this comment and concluded that no revisions to the Subchapter K rules is warranted in response to the comment. The Authority agrees with the suggestion that it is important to have an accurate understanding of the aquifer. The Authority currently has a considerable knowledge of the aquifer and continues to carry out and fund additional modeling and study of the aquifer in order to enhance its knowledge. However, the Authority believes it is appropriate to adopt the Subchapter K rules at this time. The types of seismic exploration mentioned by the commenter may be appropriate if and when the Authority determines whether to raise the withdrawal caps. Nothing in the Subchapter K rules would preclude such efforts at that time.

Public Comment:

Sharman asserts springflows do not have to flow naturally and use of pumps are appropriate. Therefore, Sharman believes springflows should be augmented. Furthermore, he maintains the aquifer will replenish itself, as it always has which makes the need for an additional water supply non-existent. Therefore, the payment of "huge" amounts of money for a federally mandated need is unnecessary. Finally, Sharman believes the Environmental Protection Agency, Fish and Wildlife Service, the Sierra Club, and the federal judiciary should refrain from interfering with the state of Texas.

Authority Response:

The Authority has reviewed this comment and concluded that no revisions to the Subchapter K rules is warranted in response to the comment. The use of "springflow augmentation," as suggested by the commenter, is the very type of effort which the Authority may consider if and when it considers whether to raise the withdrawal caps. Nothing in the Subchapter K rules would preclude consideration of such efforts issue at that time. The Authority has no control over the actions of the Sierra Club, Environmental Protection Agency, or Fish and Wildlife Service.

The new sections are adopted pursuant to the following statutory provisions contained within the Act.

Section 1.08(a) of the Act provides that the Authority "has all of the powers, rights, and privileges necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer." This section provides the Authority with broad and general powers to take actions as necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer. The rules further those objectives.

Section 1.11(a) of the Act provides that the Board of Directors of the Authority (the "Board") "shall adopt rules necessary to carry out the authority's powers and duties under this article (the Act), including rule governing procedures of the board and the authority." This section provides broad rulemaking authority to implement the various substantive and procedural programs set forth in the Act related to the Edwards Aquifer, including the permitting program.

Section 1.11(b) of the Act requires the Authority to "ensure compliance with permitting, metering, and reporting requirements and . . . regulate permits." This section, in conjunction with §1.11(a) and (h) of the Act, and §2001.004(1) of the APA, requires the Authority to adopt and enforce the Chapter 711 rules.

Section 1.11(h) of the Act provides, among other things, that the Authority is "subject to" the Administrative Procedure Act (the "APA"). This section essentially provides that the Authority is required to comply with the APA for its rulemaking, even though the Authority is a political subdivision and not a state agency, and therefore, would typically not be subject to APA requirements. Section 2001.004(1) of the APA requires agencies subject to the APA to "adopt rules of practice stating the nature and requirements of all available formal and informal procedures."

Section 1.14(a) of the Act provides that authorizations to withdraw aquifer water shall be limited in order to: protect water quality of the aquifer and surface streams to which the aquifer contributes springflow; achieve water conservation; maximize beneficial use of water from the aquifer; protect aquatic and wildlife habitat as well as federally or state-designated threatened or endangered species; and provide for instream uses, bays and estuaries.

Section 1.14(b) of the Act imposes, subject to certain limitations, an initial aquifer withdrawal "cap" for permitted withdrawals of

450,000 acre-feet per year, until December 31, 2007. The Chapter 711 Subchapter K rules explain how this cap may, under appropriate circumstances, be raised by the Authority, and other procedural details.

Section 1.14(c) of the Act imposes, subject to certain limitations, an aquifer withdrawal "cap" for permitted withdrawals of 400,000 acre-feet per year, beginning January 1, 2008. The Chapter 711 Subchapter K rules explain how this cap may, under appropriate circumstances, be raised by the Authority, and other procedural details.

Section 1.14(d) of the Act provides that either of the caps listed above may be raised by the Authority if, through studies and implementation of certain strategies, the Authority, in consultation with state and federal agencies, determines the caps may be raised. Subchapter K sets out this process.

Section 1.15(a) of the Act directs the Authority to manage withdrawals from the aquifer and manage all withdrawal points from the aquifer as provided by the Act. This section is implemented, in part, through the Chapter 711 Subchapter K rules.

Section 1.44 of the Act allows the Authority to enter into cooperative contracts with other political subdivisions for artificial recharge projects and for possible additional withdrawals as a result of those projects. The section further provides, however, that such withdrawals are not subject to the withdrawal caps.

§711.292. Applicability.

This subchapter applies only to:

(1) initial regular permits; and

(2) additional regular permits.

§711.294. Water Management Strategies.

The following water management strategies, if implemented, may potentially provide a basis to determine if there are additional groundwater supplies available from the aquifer to increase the amount of permitted withdrawals:

(1) conservation;

(2) springflow augmentation;

(3) diversions of surface water downstream of Comal and San Marcos Springs pursuant to §1.30 of the act;

(4) reuse;

(5) supplemental recharge;

(6) conjunctive management of surface and subsurface water;

(7) drought management plans; and

(8) other water management strategies that may result in additional groundwater supplies available for withdrawal from the aquifer.

§711.302. Board Order Increasing the Permitted Withdrawal Cap.

Based on the general manager's additional water supply report and the consultation report, the board may issue an order increasing the permitted withdrawal cap established in §711.164(a) and (b) of this chapter (relating to Groundwater Available for Permitted Withdrawals for Initial and Additional Regular Permits) if it finds that:

(1) the board issued an order determining that additional supplies are available for withdrawal from the aquifer pursuant to §711.298 of this subchapter (relating to Board Order Finding Additional Water Supplies);

(2) the general manager consulted with appropriate state and federal agencies concerning the proposed increase in the permitted withdrawal cap;

(3) the withdrawal of the additional groundwater supplies will not adversely affect the water quality of the aquifer;

(4) withdrawal of the additional groundwater supplies will not reduce springflows at Comal Springs and San Marcos Springs to levels prohibited by applicable federal or state law; and

(5) withdrawal of the additional groundwater supplies will not interfere with the rights of the owners of initial regular permits.

§711.304. Allocation of Additional Groundwater Supplies.

If the board issues an order under §711.302 of this chapter (relating to Board Order Increasing the Permitted Withdrawal Cap), the additional groundwater shall be allocated as follows:

(1) if the additional groundwater supplies are attributable to a water management strategy identified in §711.294(1)-(8) of this chapter (relating to Water Management Strategies) and the water management strategy is paid for by an entity other than the authority then the additional groundwater is allocated to the entity paying for the strategy. If multiple entities pay for the water management strategy, then the additional groundwater shall be allocated to those entities paying for the strategy on a *pro rata* basis consistent with their percentage contributions; or

(2) if the additional groundwater supplies are attributable to a water management strategy identified in §711.294 of this chapter (relating to Water Management Strategies) and the water management strategy is paid for by the authority, then the additional groundwater is allocated to restore on a *pro rata* basis any reductions from an initial regular permittee's maximum historical use in the following order of priority:

(A) retirements of initial regular permits made pursuant to §1.21(c) of the act and subchapter H (relating to Withdrawal Reductions and Regular Permit Retirement Rules) of chapter 715 (relating to Comprehensive Water Management Plan Implementation); and

(B) any proportionally adjusted amounts under §711.172(h) of this chapter (relating to Proportional Adjustment of Initial Regular Permits).

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009049
Gregory M. Ellis
General Manager
Edwards Aquifer Authority
Effective date: January 17, 2001
Proposal publication date: September 29, 2000
For further information, please call: (210) 222-2204

♦ ♦ ♦

SUBCHAPTER L. TRANSFERS

31 TAC §§711.320, 711.322, 711.324, 711.326, 711.328, 711.330, 711.332, 711.334, 711.336, 711.338, 711.340, 711.342, 711.348, 711.350, 711.352, 711.354, 711.356, 711.358, 711.360, 711.362, 711.364

The Edwards Aquifer Authority ("Authority") adopts new 31 TAC §§711.320, 711.322, 711.324, 711.326, 711.328, 711.330, 711.332, 711.334, 711.336, 711.338, 711.340, 711.342, 711.348, 711.350, 711.352, 711.354, 711.356, 711.358, 711.360, 711.362, 711.364, relating to the Authority's implementation of a program for regulating the transfer of groundwater withdrawal permits, permit applications and interim authorization status. These transfer rules are an integral part of the Authority's Groundwater Withdrawal Permit Program. Sections 711.320, 711.322, 711.324, 711.326, 711.328, 711.338, 711.342, 711.352, and 711.364 are adopted with changes to the proposed text as published in the September 29, 2000 issue of the *Texas Register* (25 TexReg 9900). 711.330, 711.332, 711.334, 711.336, 711.340, 711.348, 711.350, 711.354, 711.356, 711.358, 711.360, and 711.362 are adopted without changes to the proposed text and will not be republished. Sections 711.344 and 711.346 are being withdrawn due to comments received and are not being adopted at this time. The Authority adopts these rules for the purpose of satisfying its statutory obligation to adopt rules necessary to carry out the Authority's power and duties under the Edwards Aquifer Authority Act. *See* Act of May 30, 1993, 73rd Legislature, Regular Session, Chapter 626, 1993 Texas General Laws 2350, 2358-59, as amended by Act of May 29, 1995, 74th Legislature, Regular Session, Chapter 261, 1995 Texas General Laws 2505, Act of May 16, 1995, 74th Legislature, Regular Session, Chapter 524, 1995 Texas General Laws 3280, and Act of May 6, 1999, 76th Legislature, Regular Session, Chapter 163, 1999 Texas General Laws 634 ("Act").

The Act requires the Authority to implement a permitting system whereby "existing users" of groundwater from the Edwards Aquifer ("the Aquifer") and other potential users of aquifer water may apply for and receive permits issued by the Authority allowing for the withdrawal of groundwater from the Aquifer. The Act also specifies an "interim authorization" period prior to the issuance by the Authority of final initial regular permits during which existing users of the Aquifer may continue to make withdrawals until final action on permit applications by the Authority. The Act envisions a procedure whereby all or parts of these groundwater withdrawal permits, or interim authorization status, may be sold, leased, or otherwise transferred. It also places limits upon the transferability of certain interests. Sections 711.320-711.364 set forth the criteria and procedures by which groundwater withdrawal permits or interim authorization status may be transferred.

The Authority is required by the Act to implement Edwards Aquifer management programs relating to, among other things, transfers of groundwater withdrawal permits. Section 1.11(a) of the Act provides that the Board of Directors ("Board") of the Authority "shall adopt rules necessary to carry out the authority's powers and duties under (Article 1 of the Act), including rules governing procedures of the board and the authority." This section directs the Board to adopt rules as necessary to implement the various substantive programs set forth in the Act. This duty to adopt rules would includes rules related to the Authority's regulation of transfers. This duty under §1.11(a) to adopt procedural and substantive rules for its programs is incorporated into the discussion below of each definition.

A primary manner in which these various groundwater management programs will be implemented by the Authority is through the adoption of rules for each program. Rulemaking has become essential for the operation of agencies charged by the legislative branch with programmatic implementation responsibilities. Thus while the Authority's activities are derived from express and implied powers set forth in the Act, the implementation of these powers is accomplished largely through rulemaking.

In addition to the practicality of program implementation through rulemaking, there are legal requirements set forth in the Act that governs the program development of the Authority. These legal requirements are pre-existing legal "facts" adopted by the Legislature through the adoption of the Act that bind the Authority because it is a creature of the Act. In addition, there may be other facts that operate to provide contours as to the development of the transfer rules that the Authority may choose to adopt. Both types of facts, legal and otherwise, may exist to provide a factual basis for the rule as adopted. The factual basis for the transfer rules, contained in subchapter L of chapter 711, 31 Texas Administrative Code and the rational connection between the factual basis for the rule and the rule as adopted are discussed below.

The factual basis for the definition for "base irrigation groundwater" ("BIG") in §711.320(1) is the pre-existing legal based on 1.34(c) of the Act which provides that 50 percent of an initial regular permit permittee's "remaining irrigation water rights must be used in accordance with the original permit and must pass with transfer of the irrigated land." The Act does not give a name to this part of an initial regular permit that is issued for irrigation purposes. In the transfer rules of the Authority, and in other documents in which it is appropriate to cite to this category of an initial regular permit that has transfer limitations, it will be necessary to refer to this category of water. The Authority has chosen to refer to this water as BIG. In light of §1.34(c)'s creation of limitation on the transferability of initial regular permit issued for irrigation purposes it is useful to adopt a short-form definition for this category of water, namely BIG, to mean the water referred to in the second sentence of §1.34(c) of the Act. In so doing, the need to continually refer to the lengthy and cumbersome descriptive language in §1.34(c) of the Act will be eliminated. This definition provides a rational connection between the pre-existing legal facts embodied in the second sentence of §1.34(c) of the Act and the definition of BIG because the definition accurately captures the substance of §1.34(c) of the Act.

The factual basis for the definition for "groundwater withdrawal amount" in §711.320(2) are the pre-existing legal facts due to the operation of §1.14(b) and (c) of the Act (creating aggregate groundwater withdrawal "caps" for regular permits) making it necessary in the issuance of a groundwater withdrawal permit to identify the amount of groundwater that may be withdrawn from the Aquifer in acre-foot units on an annual basis. Permittees will need to know the amount of groundwater they may legally withdraw pursuant to their permit. Additionally, the Authority will need to know this amount as well for the purpose of enforcing the "caps," among other things, and to enforce the groundwater withdrawal permits under §1.11(b) of the Act, and §1.17(b) of the Act related to interim authorization groundwater withdrawal volumes. Thus, it is necessary for the Authority to determine the amounts of the groundwater that are authorized to be withdrawn pursuant to a groundwater withdrawal permit and interim authorization status. The Act does not provide a definition for the term "groundwater withdrawal amount." Because this term is likely to be regularly used by the Authority in its rules and in the general conducting of its procedures, as they relate to the transfer of groundwater withdrawal permits and interim authorization status, as well as by the regulated community that will interact with the Authority, the Authority has determined that it is useful to define this term. There is a rational connection between these pre-existing legal facts and the definition of "groundwater withdrawal amount" in §711.320(3) because this definition accounts for withdrawal in acre-feet per annum that are authorized by groundwater withdrawal permits and pursuant to interim authorization status.

The factual basis for the definition of "transfer" in §711.320(3) are derived initially from the pre-existing legal facts derived from the Act, as well as other facts that further determine the nature of the meaning of the term "transfer." The title of §1.34 of the Act is "Transfer of Rights." Section 1.34(a) prohibits the place of use from being located outside of the boundaries of the Authority. Section 1.34(b) provides for the sale of conserved water. Section 1.34(c) authorizes leases of 50 percent of the groundwater withdrawal amount of an initial regular permit issued for irrigation purposes, and limits the transferability of the place and purpose of use of the remaining 50 percent of such permits. The term "transfer" appears in §1.34(c) the Act. The concept of "transfer" will often be considered as part of the terminology used by the Authority in its procedural rules related to the transfer of groundwater withdrawal permits. The Act does not provide a definition for the term "transfer." Because this term is likely to be regularly used by the Authority in referring to transfers in its rules, the general facilitation of its procedures, in relation to the transfer of permits, and by the regulated community interacting with the Authority as transferors and transferees, as well, the Authority has determined that the definition of this term will be useful. A review of §1.34 shows that it refers to transfers as incorporating at least transfers of ownership, rights to make withdrawals, rights to place to beneficial use, place of use, and purpose of use. Transfers of the place of use also almost invariably result in the a transfer of the location of the point of withdrawal. If the transfer of the point of withdrawal is to an existing point of withdrawal an increase in the maximum rate of withdrawal may also result for the existing well. The Authority has not yet chosen to regulate the period of withdrawal and, therefore, this aspect of a potential transfer has been deleted from the definition. There is a rational connection between this factual basis and the definition of "transfer" in §711.320(5) because all of these aspects of a transfer have been incorporated into the definition of transfer.

The factual basis for the definition for "unrestricted irrigation groundwater" ("UIG") in §711.320(4) is the pre-existing legal fact that the first sentence of 1.34(c) of the Act provides that 50 percent of the groundwater withdrawal amount of an initial regular permit issued for irrigation purposes may be leased by the owner of the permit The Act does not give a name to this part of an initial regular permit that is issued for irrigation purposes. In the transfer rules of the Authority, and in other documents in which it is appropriate to cite to this category of an initial regular permit that has no transfer limitations, it will be necessary to refer to this category of water. The Authority has chosen to refer to this water as UIG. In light of §1.34(c)'s creation of no limitation on the transferability of this part of an initial regular permit issued for irrigation purposes it is useful to adopt a short-form definition for this category of water, namely UIG, to mean the water referred to in the first sentence of §1.34(c) of the Act. In so doing, the need to continually refer to the lengthy and cumbersome descriptive language in §1.34(c) of the Act will be eliminated. This definition provides a rational connection between the pre-existing legal facts embodied in the first sentence of §1.34(c) of the Act and the definition of UIG because the definition accurately captures the substance of §1.34(c) of the Act.

The factual basis for the definition for "water conservation equipment" in §711.320(5) is the pre-existing legal fact of 1.34(b) of the Act that provides that conserved water may be sold by the owner of a groundwater withdrawal permit after the installation of "water conservation equipment." This term is not defined by the Act. Because this term is likely to be regularly used by the Authority in referring to transfers in its rules, the general facilitation of its procedures, in relation to the transfer of permits, and by the regulated community interacting with the Authority as transferors and transferees, as well, the Authority has determined that the definition of this term will be useful. A review of §1.34(b) shows first that the equipment must be susceptible to being "installed." Thus, the equipment must be a tangible physical device that is capable to being affixed to or made part of the infrastructure of an irrigation delivery system. The Act gives no guidance as to the nature of the equipment, other than that the equipment must result in conservation of water. There is a rational connection between this factual basis and the definition of "water conservation equipment" in §711.320(6) because these aspects derived from §1.34(b) of the Act have been incorporated into the definition of transfer.

The factual basis for §711.322(a) lies in the fact that transfers are within the province of groundwater withdrawal permits. The basics elements of transfers-ownership, rights to make withdrawals, rights to place to beneficial use, place of use, purpose of use, point of withdrawal, and rate of withdrawal-all related to groundwater withdrawal permits. Because the Act provides special provisions for "interim authorization" withdrawals, it could not reasonably be expected that between the period of time from June 1, 1993 forward to the time when final initial regular permits will have been issued (an accomplishment which will have taken the Authority several years) that the water market envisioned by the Act would have remained static and the ownership of applications for initial regular permits would not have changed hands and other aspects of transfers may not have changed as well. Subsection (a) of §711.322 so provides that subchapter L applies only to transfers of groundwater withdrawal permits and interim authorization status. For that reason the Authority has added in §711.322(a)(3) the reference to term and emergency permits to make §711.322 consistent with §711.324(a). Also, in §711.322(a)(3) the reference to "aquifer recharge and storage permits" has been deleted because this permit does not authorize the withdrawal of groundwater.

The factual basis for §711.322(b) is that water services contracts do not generally result in transfers of ownership, place or purpose of use, or points of withdrawal. The typical water service contact normally is an agreement to deliver water through a pipeline to a master meter for the use of the entity contracting for the supply. The most likely transfer in this context would be a change in the place of use. This rule provides that if, in fact, a transfer would occur, then a water service contract would have to be processed as a transfer, while recognizing that most water service contracts are for retail or wholesale service with no transfers resulting. Additionally, this subsection notes that retirements of groundwater withdrawal permits are not transfers. The factual basis for this result is that the Authority does not take title to the ownership of the permits. A retirement of a permit is merely the elimination of the permit from the water accounting and permit records of the Authority usually based on the payment of compensation. There can be no transfer of any attribute of the permit because the permit is removed as an extant legal instrument from the Authority's records. Finally, this subsection also provides that suspensions of groundwater withdrawal permits are not transfers. The factual basis for this result is that suspensions are the cessation, for a prescribed period of time, of the right to withdraw groundwater from the Aquifer usually based on the payment of compensation. Neither the Authority, nor a third-party, takes title to the ownership of the permit. No other attribute of a permit is changed because merely the right to withdraw is temporarily suspended. No other third-party accedes to the right to withdraw.

Section 711.324 identifies the types of transfers that are prohibited. Subsection (a) provides that term, emergency, and monitoring well permits are only transferrable as to ownership. The factual basis for this rule is that each of these groundwater withdrawal permits tend to be very site or project specific. Any deviation from the set of facts that provided the basis for the Authority's issuance of the permit would essentially render the permit of doubtful value. If a person needed one of these permits for his site or project, he would be better served by simply filing an application for a new permit as may be appropriate. As for the non-transferability of exempt well status, this result necessarily follows because exempt well status is conferred only to the ownership of wells drilled on certain lands (assuming all applicable eligibility criteria are satisfied in §1.33 of the Act). Because the status attaches only to wells drilled on certain lands, exempt well status cannot be transferred except as to ownership of the lands in question. Because a well construction permit does not authorize the withdrawal of groundwater, the reference to this permit has been dropped from §711.324(a). The factual basis for subsection (b) is found in the pre-existing legal facts contained in §1.34(a) of the Act which prohibits out-of-Authority places of use. The factual basis for subsection (c) is found in the pre-existing legal facts contained in the second sentence of §1.34(c) of the Act which creates the appurtenancy of the place and purpose of use for BIG. The factual basis for the proviso in this subsection will be discussed in account of §711.338.

Section 711.326 provides that, for recharge recovery permits, only ownership, purpose of use and place of use may be transferred. The factual basis for this rule is that this permit tends to be very site or project specific. Any deviation from the set of facts that provided the basis for the Authority's issuance of the permit would essentially render the permit of doubtful value. If a person needed to transfer the point of withdrawal of a recharge recovery permit, he would be better served by simply filing an application for a new or amended recharge recovery permit as may be appropriate. The reference to "aquifer recharge and storage permits" has been deleted because this permit does not authorize the withdrawal of groundwater.

Section 711.328(a) provides that ownership of a regular permit may generally be transferred separately from ownership of the place of use or point of withdrawal. The factual basis for this subsection is that the Act creates no general prohibition on the transfer of a groundwater withdrawal permit separate from the place of use or point of withdrawal. Absent such a prohibition, the general rule favoring alienability would prevail. Subsection (b) also provides that transfer of ownership of the place of use or point of withdrawal will generally be presumed to transfer ownership of the regular permit, unless an express reservation of rights is made by the transferor. The factual basis for this subsection is that the intent of the parties as stated in the transaction documents should control disputes related to the transaction. If the transferor is silent in the transfer documents, then general rules would normally ascribe an intent to convey. Subsections (c) and (e) provide that ownership of BIG will pass with the transfer of ownership of the irrigated land owned by the owner of the original initial regular permit and may not be reserved to the landowner. Subsection (c) has been modified to clarify that the appurtenancy of BIG is attached to the irrigated land owned by the owner of the original initial regular permit. Subsection (d), on the other hand, provides that ownership of UIG need not necessarily pass with the transfer of ownership of the place of use or point of withdrawal. The factual basis for these two subsections is found in the pre-existing legal facts found in section 1.34(c) of the Act. If a transferor can transfer the place or purpose of use for all of UIG, there is no compelling reason that in the transfer of the ownership of the irrigated lands that the UIG could not be reserved to the transferor. The opposite for BIG is not at all the case in light of §1.34(c).

Section 711.330 provides that permittees and those qualifying for interim authorization status are entitled to make transfers of permit applications and associated interim authorization status or permits. The factual basis for this rule is that only the owner of a groundwater withdrawal permit or an application for an initial regular permit has the legal authority and capacity to make a transfer of the legal rights associated therewith.

Section 711.332 defines when and for what term transfers may be made. The factual basis for subsection (a) is grounded in the pre-existing legal facts embodied in §1.17(a) and (d) of the Act. A transfer of interim authorization status may quite clearly only be effective during the term of the interim authorization period as set forth in the Act. As for subsection (b) related to groundwater withdrawal permits, the term may begin only after the permit issued and may continue in effect only as provided by the transferor and transferee in the transaction documents as applied for in the application to transfer and amend as recognized in the Authority's approval of the transfer.

Section 711.334 provides that regular permittees are generally free to transfer non-irrigation permits without restrictions as to the place or purpose of use. The factual basis for this section is that the Act creates no general prohibition on the transfer of a groundwater withdrawal permits issued for non-irrigation purposes. Absent such a prohibition, the general rule favoring alienability would prevail.

Section 711.336 provides that regular permittees are generally free to transfer UIG without restrictions as to the place or purpose of use. The factual basis for these is found in the pre-existing legal facts found in §1.34(c) of the Act. This subsection authorizes a transferor to transfer the place or purpose of use of all of UIG. The Act creates no general prohibition on the transfer of a groundwater withdrawal permits issued for UIG. Absent such a prohibition, the general rule favoring alienability would prevail.

Section 711.338(a) prohibits the transfer of the place or purpose of use of the portion of an initial regular permit issued for BIG. The factual basis for this rule is found in the pre-existing legal facts contained in the second sentence of §1.34(c) of the Act which creates the appurtenancy of the place and purpose of use for BIG. The Authority interprets the appurtenancy rule to apply to the irrigated lands owned by the owner of the original initial regular permit which are recognized as the place of use therein. Because BIG must transfer with the ownership of the irrigated lands to which BIG is appurtenant, and the irrigated lands are owned by the transferor no useful purpose can be served by preventing the owner of the initial regular permit from transferring the place of use to another place of use owned by the same person. Because §1.34(c) only operates upon the transfer of the irrigated lands to a third-party transferor, this provides the factual basis for subsection (b) of this rule.

Section 711.340 provides that an application may be submitted to the Authority to convert BIG to UIG. The factual basis for subsection (a)(4) is that the irrigated land to which BIG is appurtenant may not always remain in irrigation. With the passage of time it may be developed such that irrigation is no longer possible. Under such a circumstance, if BIG is not authorized to be converted to UIG, then the owner of the developed (formerly) irrigated lands will own an initial regular permit for a place at which it is no longer possible to beneficially use the groundwater withdrawn from the Aquifer for irrigation. This would create the absurd result that the initial regular permit could not be transferred to another place or use for the same or another purpose of use. Additionally, the landowner would have made the decision to take the land out of irrigation agriculture and thereby remove its place in the market for this purpose. The Authority has no regulatory authority over the land use decisions of the owner of the irrigated lands. If the market had dictated through the decisions of the owner of the irrigated lands that the water was no longer needed for irrigation purposes, the Authority has no particular regulatory interest in preventing the transfer of the water to another place or purpose of use. The factual basis for subsection (a)(5) is the pre-existing legal fact of 1.34(b) of the Act that provides that conserved water may be sold by the owner of a groundwater withdrawal permit after the installation of water conservation equipment. This operation of this section ensures that the owner of a groundwater withdrawal permit who conserved groundwater withdrawals may not be considered to have abandoned that part of the permit because he no longer can beneficially use the conserved water for the originally permitted purpose of use. Section 1.34(b) of the Act does not necessarily limit itself to an irrigation purpose of use. However, neither §1.34 nor other sections of the Act place any transfer limitations on the transfer of the place or purpose of use of groundwater withdrawal amounts issued for non-irrigation purposes. Thus, other than rejecting the common law of the retention of the beneficial use of conserved water, and because 50 percent of initial regular permits issued for irrigation purposes is freely transferable as to place and purpose of use due to the operation of the first sentence of §1.34(c), §1.34(b) can only have an import as to its relationship to BIG. If water conservation equipment is installed such that the total amount of BIG is no longer required to accomplish the same amount of irrigation, the objective of the Legislature in enacting the second sentence of §1.34(c) of the Act in order to protect economies associated with irrigated agriculture is still served even if that part of BIG that is conserved is authorized to be transferred to another place or purpose of use. No meaningful useful purpose is served by not allowing the transfer of that part of BIG that is conserved under §1.34(b). This resolution of the interaction between these two subsections fosters the intent of both subsections. Because 50 percent of initial regular permits issued for irrigation purposes is freely transferable as to place and purpose of use, it is unnecessary to determine whether this water may be transferred due to the installation of water conservation equipment. Thus, the provision of procedures to authorize the conversion of BIG to UIG is reasonable to make the water available in the market for other uses at other places of use.

Section 711.342 sets out the criteria and procedure by which the board shall consider and approve an application to convert BIG to UIG. For the conversion to UIG, the board must find, primarily, that the land use has changed such that the land no longer can qualify for an agricultural land ad valorem property tax reduction, or that groundwater from the Aquifer will be conserved by the applicant's installation of water-conserving equipment on the property. The factual basis for this rule is described above in the discussion of §711.340.

Section 711.348 requires that the Authority be given notice within 30 days of the transfer of ownership of a permit or permit application, and sets forth the procedures to be followed by the general manager upon receipt of the notice. The factual basis for this rule is that, in order to properly manage and enforce permitted and interim authorization withdrawals, the Authority must have accurate and complete water accounting and permitting records. The only way it can reasonably attain the information from private sector transfers in the water market is to require that the transferee file notices of change of ownership with the Authority reasonably proximate to the date of the transaction. The 30-day period gives the transferee adequate time to prepare the notice of change of ownership yet timely provides the information to the Authority such that it can modify its records accordingly.

Section 711.350 requires that, for transfers of interests other than ownership, an application to transfer and amend a regular permit or application for a regular permit must be submitted to and approved by the Authority. The rule further provides that no transfer is generally effective until the Authority has issued a final order granting the application to transfer. The factual basis for this rule is that, in order to properly manage and enforce permitted and interim authorization withdrawals, the Authority must have accurate and complete water accounting and permitting records. The only way it can reasonably attain the information from private sector transfers in the water market is to require that the transferee file applications to transfer and amend with the Authority, and receive approval from the Authority prior to the transferee being authorized to make withdrawals pursuant to the transaction.

Section 711.352 sets out the criteria by which the board or general manager shall determine whether an application to transfer and amend a regular permit or application shall be granted. Among other things, the Authority must find either: (1) that the point of withdrawal of the permit is not transferred from a point west of Cibolo Creek to east of Cibolo Creek; or (2) if the point of withdrawal of a permit is transferred from a point west to east of Cibolo Creek, then that aquatic and wildlife habitat, as well as threatened and endangered species and springflows at Comal and San Marcos, will be protected. Transferring the point of withdrawal of permit from west Cibolo Creek to east of Cibolo Creek has the potential to negatively impact springflows at Comal and San Marcos Springs and their aquatic and wildlife habitats. If the radius of influence of a well or a well field encompasses flowpaths to these springs, withdrawal from those wells could decrease water levels in the aquifer and thus, decrease springflows. Additionally, the artesian zone of the aquifer east of Cibolo Creek is narrower, relative to west of Cibolo Creek. If withdrawal rates are allowed to increase in the narrow artesian zone area, the potential of negative impacts on artesian pressure and springflow will also increase. Cibolo Creek was also chosen as a boundary for greater scrutiny of transferring withdrawal points because it is an easily identifiable surface feature.

Section 711.354 requires the Authority to create and maintain a database of all transfers. The factual basis for this rule is that, in order to properly manage and enforce permitted and interim authorization withdrawals, the Authority must have accurate and complete water accounting and permitting records. The only way it can reasonably maintain such records is to create them in the first place.

Section 711.356 requires the transferee, within 30 days, to file a record of the transfer in the deed records of: (a) the counties in which the point of withdrawal and place of use are identified in the regular permit or application, and (b) the counties to which the point of withdrawal and place of use are transferred. The factual basis for this rule is that title insurance companies, real estate appraisers, taxing entities, and potential transferees, need an organized system to track transfers for each of their respective purposes. While the Authority will also maintain an accurate data base of transfers that are filed with it, local recordation will provide a more convenient and customary records management system that each of these entities can access for their purposes.

Section 711.358 provides that no transfer is effective until a notice has been filed with the Authority or the board has issued an order granting the transfer application. The factual basis for this rule is that, in order to properly manage and enforce permitted and interim authorization withdrawals, the Authority must have accurate and complete water accounting and permitting records. The only way it can reasonably maintain such records is for transferees to file the transfer transactions with the Authority. The best incentive for transferees to file such documents with the Authority will be for the Authority not to recognize the transfer for enforcement purposes until the transfer has been approved by the Authority. In creating a bright line rule for when a transfer becomes effective the Authority give notice to transferors and transferees of how it will maintain its water accounting and permitting records for purposes of enforcement of groundwater withdrawals.

Section 711.360 provides that all transfers are subject to the Act, the Authority's rules, any regular permit conditions, and all other applicable laws. The factual basis for this rule is that, as for any program of the Authority, relevant legal parameters applicable to transfers will apply to regulate the transfer transaction.

Section 711.362 provides that if a federal agency transfers its permit or application but continues to make withdrawals as if the transfer had not been made, then the board or general manager shall deny the transfer application. The factual basis for this rule is that a single legal authority may provide the basis for only a single entity to make withdrawals from the Aquifer. The Authority is unable to allow multiple withdrawal by multiple parties based on the same legal authority.

Section 711.364 requires the general manager to monitor the impact of certain transfers and, within two years of the effective date of the transfer rules, prepare a report to the board making findings and recommendations concerning the impacts. The primary concern of transferring large amounts of water within the aquifer system is the risk of impacting springflows at Comal and San Marcos Springs and their aquatic ecosystems. As indicated in the factual basis for rule 711.352, maintaining the maximum distance between major points of withdrawal and the springs will serve to abate possible negative effects on springflow. Periodic reports to the board regarding an assessment of any impacts of transfers will ensure that the impacts, if any, do not accumulate without notice.

The Authority has received public comments to the proposed rules and has prepared responses thereto as set forth below:

Five public hearings were held on these Chapter 711, Subchapter L rules and other rules proposed by the Authority on: Monday, October 2, 2000 at 6:00 p.m. at the conference center of the Edwards Aquifer Authority, 1615 N. St. Mary's Street, San Antonio, Texas; Tuesday, October 3, 2000 at 6:00 p.m., at St. Paul's Lutheran Church, 1303 Avenue M, Hondo, Texas; Wednesday, October 4, 2000 at 6:00 p.m., at the San Marcos Activity Center, 501 E. Hopkins, San Marcos, Texas; Wednesday, October 11, 2000 at 6:00 p.m., at the Sgt. Willie DeLeon Civic Center, 300 E. Main Street, Uvalde, Texas; and Thursday, October 12, 2000, at 6:00 p.m., at the New Braunfels Civic Center, 380 S. Seguin Avenue, New Braunfels, Texas.

Oral and/or written comments were provided by San Antonio Water System ("SAWS"), New Braunfels Utilities ("NBU"), Andrew J. Aelvoet on behalf of Southwest Texas Federal Land Bank Association ("FLB"), The City of Shertz ("Shertz"), Steve Kosub ("Kosub"), Patricia Verstuyft ("Verstuyft"), David Archer on behalf of Del Monte Foods, Texas Food Processors, and Texas Vegetable Association ("Archer"), and Howard D. Bye on behalf of the City of Selma ("Selma") and Texas Farm Bureau ("TFB").

Section 711.320:

Public Comment No. 1:

SAWS commented on several subsections of proposed §711.320.

Section 711.320(1):

SAWS's comments relate to the definition of "base irrigation groundwater ("BIG") in relation to proposed §§711.324 and 711.338 limitations on the transfer of BIG. According to SAWS, the Authority is exceeding its statutory authority by arbitrarily restricting the "purpose and place of use" of 50% of the authorized groundwater withdrawal amounts in initial regular permits ("IRP") for irrigation use. Specifically, SAWS points to §1.34 of the Edwards Aquifer Authority Act[2] which states, in pertinent part, as follows:

[2] Act of May 30, 1993, 73rd Legislature, Regular Session, Chapter 626, 1993 Texas General Laws 2350; as amended by, Act of May 28, 1995, 74th Legislature, Regular Session, Chapter 261, 1995 Tex. Gen. Laws 2505; Act of May 16, 1995, 74th Legislature, Regular Session, Chapter 524, 1995 Texas General Laws 3280; and Act of May 6, 1999, 76th Legislature, Regular Session, Chapter 163, 1999 Texas General Laws 634.

(b) The authority may establish a procedure by which a person who installs water conservation equipment may sell the water conserved.

(c) A permit holder may lease permitted water rights, but a holder of a permit for irrigation use may not lease more than 50 percent of the irrigation rights initially permitted. The user's remaining irrigation water rights must be used in accordance with the original permit and must pass with transfer of the irrigated land.

SAWS believes this section implies that all rights are transferrable. Also, they maintain that subsection (b) of §1.34 is a "statutory revision to the common-law rule that conserved water may be transferred" while subsection (c), which SAWS maintains the Authority is relying on, only addresses leases. Therefore, SAWS asserts that because the Legislature did not address permanent transfers of ownership, but only leases, the canons of statutory construction dictate that the failure to address an issue, although a related issue may be addressed, should be given a purposeful construction. Alternatively, SAWS argues that if statutory authority exists as a basis for such a limitation, the limitation on the alienation of a landowner's right to transfer property, is without reasonable justification, and would be found unconstitutional.

Finally, SAWS contends the conclusions reached by the Authority in its rules assessment process and those expressed in the Public Benefit and Cost Note ("Note") for these rules differ. The Note states that Subchapter L will protect Edward Aquifer groundwater in a way that supports the economic region dependent upon it. Whereas, other rules assessment argue that free transfer of BIG would have no more impact on the regional economy than restricting their transfer.

Section 711.320 (2):

In reference to section 711.320(2), SAWS requests more flexibility in the definition of "conserved irrigation groundwater" ("CIG"). SAWS asserts that the conservation of groundwater may not necessarily occur due to installation of conservation equipment and suggests the following changes:

(2) Conserved irrigation groundwater-The amount, in acre-feet per annum, of base irrigation groundwater conserved, for which a final order...

Section 711.320 (4):

Regarding §711.320(4), SAWS suggests the use of a less restrictive term than "physically impossible" in the definition of "restricted irrigation groundwater" ("RIG").

Section 711.320(7):

SAWS contends that because the installation of conservation equipment may not result in the conservation of irrigation groundwater, the effect of conservation practices should not be excluded from §711.320(7). Therefore, SAWS requests that the following language be substituted for §711.320(7):

(7) the implementation of irrigation best management practices, as outlined in the Authority's groundwater conservation plan, or the installation of conservation equipment, which results in a quantifiable lesser amount of groundwater from the aquifer being required for irrigation purposes at the place of use identified in a regular permit, or an application for a regular permit.

Authority Response:

The Authority received the above-referenced comments and disagrees with them, in part, and agrees with them in part, although for differing rationale.

Relative to §711.320(1), the basis for this determination is that the comment of SAWS goes more to the transfer limitation contained in §711.324(c) and 711.338 rather than the nature of the definition of BIG in §711.320(1). SAWS does not recommend any particular changes to §711.320(1), other than by inference to eliminate this definition. Based on the Authority's response below to the comments to §§711.324(c) and 711.338, a definition for BIG would be required. In light of the above, the Authority has not modified §711.320(1).

Relative to SAWS' comment to §711.320(2), the basis for the this determination is that §1.34(b) of the Act requires that water may not be considered to be "conserved" unless "a person . . . *installs* water conservation equipment . . . ." (emphasis added). SAWS seems to be suggesting that the Authority may consider groundwater to be "conserved" even if water conservation equipment is not installed. As used in §1.34(b) of the Act, the term "installs" is readily construed to require the actual fitting, equipping or application of water conservation equipment that results in the conservation of water. Thus, it is logical to infer that water may be considered to be conserved only after water conservation equipment of some kind has actually been installed. Therefore, by referring to "after the installation of water conservation equipment," §711.320(2) more closely follows the meaning of the term "installs" as it is used in §1.34(b) of the Act. However, after review of this section, the Authority has determined that it is unnecessary because it is subsumed by the definition of UIG and the substantive conversion concepts related to conservation in §711.342(a)(5) (formerly 711.342(b)(4)). In light of the above, the Authority has deleted §711.320(2). Moreover, all references to "conserved irrigation groundwater" have been deleted from the rules in §§711.320(1)(B), 711.340, and 711.342 (b) (formerly 711.342(c)). Additionally, the separate conversion rules for conserved irrigation groundwater in subsection (b)(1)-(3) is no longer required and these subsections have been deleted. Finally, a review of the authorized place and purpose of use for BIG, after conversion to conserved irrigation groundwater, shows that conserved irrigation groundwater becomes indistinguishable from UIG. Therefore, §711.346 is longer required and has been deleted. The modifications are set out below in the final rules.

Relative to SAWS' comment to §711.320(4), the basis for this determination is that §1.34(c) of the Act provides, in relevant part, that a permittee's "remaining (50% of the groundwater withdrawal amount of an IRP issued for irrigation purposes) *must* be used in accordance with the original (initial regular) permit *and must* pass with transfer of the irrigated land (emphasis added)." The "irrigated land" referred to in §1.34(c) is the place of use identified in the original IRP. The Authority interprets these mandatory use and transfer requirements as creating an appurtenance to the place of use identified in the original IRP for irrigation purposes of the 50 percent of the groundwater withdrawal amount recognized in the IRP. Other than the "must use" and "shall pass" language employed in §1.34(c), the Act does not provide other guidance as to the nature or force of this appurtenance. However, the Authority interprets this rather strong language as creating an appurtenance that carries considerable force and should not otherwise be transferred separately and distinctly from the place of use of the original IRP for other than a very strong and compelling reason. SAWS comments that the "physically impossible" standard is too restrictive and should be relaxed, although it does not offer alternative language. The creation by the Legislature of this appurtenancy only for irrigation IRPs through such dominant language suggests an intent by the Legislature to provide a base amount of groundwater supply that is not subject to transfer from irrigation to municipal or industrial uses, absent extraordinary circumstances. The Legislature made such a provision in order to protect the economies within the jurisdiction of the Authority that are dependent on irrigated agriculture. The Authority had proposed a "physically impossible" standard for at least two reasons. First, the "physical impossibility" standard bears a reasonably substantial correlation to weight and gravity of the statutory language selected by the Legislature in §1.34(c) of the Act. Second, it will be physically impossible to apply the groundwater withdrawn from a well to the place of use of an irrigation IRP generally if the land use at the place of use has been irretrievably changed from irrigation to some other economic activity resulting in a change in the purpose of use to municipal or industrial. In so doing, the owner of the place of use will have evidenced his intent to retire from irrigated agriculture in favor of some other economic use at the place of use. The Authority has no regulatory authority over the economic use that may occur on a place of use owned by one of its permittees. Although, the Legislature, through §1.34(c) of the Act, has given the Authority the role of managing adequate quantities of groundwater (as determined by the Legislature through the 50 percent appurtenancy rule) to support irrigated agriculture, at least as long as the regional economy through the private sector's land use decisions deems this economic activity to be an important part of the economic mix for the region. As the private sector over time retires land from irrigated agriculture in favor of other economic uses, it is reasonable that the groundwater dedicated to this use under the 50 percent appurtenancy rule, would be capable of being to be freed up for other economic uses as the regional market may dictate. Moreover, once one of its irrigation permittees has made the business judgment to irretrievably withdraw land from irrigated agriculture in favor of a municipal or industrial use, then the Authority will need probative evidence on which to rely for this determination and thereby free up the groundwater for other economic uses. The best evidence of this will be the land use decisions made by the Authority's irrigation permittees. This probative evidence would have come in the form of the physical impossibility standard in §711.320(4) (now the change in land use standard). However, based on comments to 711.342 and §711.344, the Authority has determined that this section is no longer necessary because it is subsumed by the definition of UIG and the substantive conversion concepts related to change in land use in §711.342(a)(4) with further basis for this determination found below in the discussion of §711.344. In light of the above, the Authority has deleted §711.320(4).

Relative to SAWS' comment to §711.320(7), the basis for this determination is same as that provided in the discussion of §711.320(2). In light of the above, the Authority has not modified §711.320(7).

Sections 711.324; 711.326; 711.338

Public Comment No. 2:

SAWS maintains, in reference to §711.324(a), that the rules should not preclude aquifer storage and recovery projects that operate via leased wells. SAWS made this same comment in reference to §711.326 concurrently.

SAWS proposes altering §711.324(b) in light of the argument that many water utilities already have certificated areas outside the boundaries of the Authority. Therefore, water withdrawn from the aquifer may have previously been used outside the Authority's boundaries when the Act was passed. Due to potential commingling, SAWS contends future system extensions will either make monitoring difficult or require the duplication of infrastructure. SAWS requests the following change:

(b) The place of withdrawal for any permit or interim authorization status may not be transferred to a location outside the boundaries of the Authority.

Authority Response:

The Authority received the above-referenced comments and disagrees with them in part and agrees with them in part. Relative to §711.324(a), the basis for this determination is that no part of §711.324(a) relates to aquifer storage and recovery projects and therefore could not operate to preclude the use of leased wells for these projects. While §711.326 does bear on aquifer recharge, storage and recovery projects, again nothing in this rule precludes the use of leased wells. Upon review of §711.326, because aquifer storage and recovery permits do not authorize the withdrawal of groundwater the Authority agrees that reference to these permits should be deleted.

The basis for disagreeing with the SAWS proposal to alter §711.324(b) to substitute place of use with place of withdrawal is that this proposal would be contrary to §1.34(a) of the Act in which the Legislature instructed the Authority that "water withdrawn from the aquifer *must* be used *within* the boundaries of the authority." In light of the above, the Authority has not modified §711.324, but had modified §711. 326 accordingly as set forth below in the final rules.

Public Comment No. 3:

FLB objects to proposed rule §711.324(c) because it purportedly exceeds the scope of the Authority's power. According to the commenter, the Legislature did not intend to place a limitation on the transfer of BIG from one location to another. FLB suggests to following revision:

(c) the purpose of use for all or part of the base irrigation ground water component of either an initial regular permit or interim authorization status is not transferrable.

Authority Response:

The Authority received the above-referenced comment and agrees with the recommended change in part, although it disagrees with the rationale of the commenter. The basis for this determination is that as noted above in the discussion of the comments related to §711.320, by creating the appurtenancy rule in §1.34(c) of the Act, the Legislature evidenced its intent to provide a base amount of groundwater supply that is not subject to transfer from irrigation to municipal or industrial uses in order to protect the economies in the Edwards Aquifer region that are dependent on irrigated agriculture. However, the Legislature did not distinguish between the various subregions within the jurisdiction of the Authority, but instead focused on irrigated agriculture, regardless of the location of this activity within the boundaries of the Authority. The basic point of §1.34(c) is that groundwater should be available for irrigation purposes at the place of use identified in the original IRPs issued by the Authority. However, if a single owner owns more than one place of use at which the groundwater could be beneficially used for irrigation purposes, the purpose of the appurtenancy rule would not be served by prohibiting a transfer of BIG to another place of use owned by the owner of the BIG if the groundwater will continue to be used for irrigation purposes. Irrigation groundwater would continue to be used for irrigation purposes. However, if the owner of the place of use identified in the IRP to which BIG is appurtenant sought to transfer the ownership of the place of use, then the appurtenancy rule would control over the transfer of BIG to another place of use owned by the transferor and the transferee would acquire BIG due to the operation of §1.34(c) of the Act. In light of the above, the Authority has modified §§711.324 and 711.338 accordingly, as set out below in the final rules.

Public Comment No. 4

SAWS's comments relate to the definition of "base irrigation groundwater" ("BIG") in relation to proposed §§711.324 and 711.338 limitations on the transfer of BIG. According to SAWS, the Authority is exceeding its statutory authority by arbitrarily restricting the "purpose and place of use" of 50% of the authorized groundwater withdrawal amounts in initial regular permits ("IRP") for irrigation use. Specifically, SAWS points to §1.34 of the Act which states, in pertinent part, as follows:

(b) The authority may establish a procedure by which a person who installs water conservation equipment may sell the water conserved.

(c) A permit holder may lease permitted water rights, but a holder of a permit for irrigation use may not lease more than 50 percent of the irrigation rights initially permitted. The user's remaining irrigation water rights must be used in accordance with the original permit and must pass with transfer of the irrigated land.

SAWS believes this section implies that all rights are transferrable. Also, they maintain that subsection (b) of §1.34 is a "statutory revision to the common-law rule that conserved water may be transferred" while subsection (c), which SAWS maintains the Authority is relying on, only addresses leases. Therefore, SAWS asserts that because the Legislature did not address permanent transfers of ownership, but only leases, the canons of statutory construction dictate that the failure to address an issue, although a related issue may be addressed, should be given a purposeful construction. Alternatively, SAWS argues that if statutory authority exists as a basis for such a limitation, the limitation on the alienation of a landowner's right to transfer property, is without reasonable justification, and would be found unconstitutional.

Finally, SAWS contends the conclusions reached by the Authority in its rules assessment process and those expressed in the Public Benefit and Cost Note ("Note") for these rules differ. The Note states that Subchapter L will protect Edward Aquifer groundwater in a way that supports the economic region dependent upon it. Whereas, other rules assessment argue that free transfer of BIG would have no more impact on the regional economy than restricting their transfer.

SAWS comments on these rules as they relate to limitations on the transferability of BIG. It is SAWS' position that there is no statutory authority for such a limitation and that the Authority relies on 1.34 of the Act to support these rules. However, that section refers only to leases of irrigation IRPs and not to a conveyance of an irrigation IRP other than by a lease. It maintains that there is no clear statutory authorization for a 50 percent limitation. SAWS suggests the Authority seek guidance from the Attorney General with regard to interpretation of the provision. SAWS also points out that the rules assessment analyzed the economic impact of the alternative which is to have no restriction on BIG and that the rules assessment advised the Authority that limitations on transfers does not protect the economy to any greater extent than removal of that provision altogether.

Authority Response:

The Authority received the above-referenced comments and disagrees with them. The basis for this determination is, as discussed above in the Authority response to Public Comment No. 1, the second sentence of §1.34(c) of the Act contains the Legislature's expression that limitations be placed on the transferability of the place and purpose of use of IRPs issued for irrigation use. In implementing this section of the Act, the Authority finds express statutory authority to restrict the transfer of the place and purpose of use of 50% of the groundwater amount authorized in an IRP for irrigation use. SAWS refers to §1.34(b) of the Act for the proposition that IRPs are generally transferrable because §1.34(b) modifies the common-law rule that conserved water may be transferred rather than lost back to the water resource for future appropriation due to the operation of principles of beneficial use law. The Authority generally agrees with this reading of §1.34(b). The Authority has implemented this section in proposed §§711.320(2), 711.340, 711.342, and 711.346. SAWS further comments that subsection (c) of §1.34 applies only to leases. While the Legislature, in the first sentence of §1.34(c), specifically addressed leases, the second sentence of this subsection necessarily applies to leases and sales. Consider the context in which the owner of an IRP for irrigation purposes (transferor) transfers, by a lease, the place and purpose of use of the unrestricted irrigation groundwater ("UIG"), leaving only BIG appurtenant to the place of use identified in the original IRP. The transferor (as the lessor) would retain a reversionary interest in the UIG, and full fee simple ownership interest in the BIG. The second sentence of subsection (c), however, would dictate that if the transferor transferred the place of use to a third-party (transferee), then irrespective of the transferor's reversionary interest in the UIG, BIG would nonetheless transfer to the transferee by operation of law. Based on §1.34(c), the transferor is without authority to alienate BIG from the original place of use. This same result would necessarily follow *a priori* in a sales context in which the transferor retains no property interest in UIG after its sale to a third-party. The transferor is without authority to separate the BIG from the original place of use by transfer. The transferor's fee simple interest in BIG would remain the same as if UIG had been leased. The lease or sale of UIG has no bearing on the nature of the ownership interest of the transferor in BIG, and its transferability is based on the second sentence of §1.34(c).

Whether the Legislature's restrictions on the transfer of the place or purpose of use of an IRP for irrigation purposes is constitutional is beyond the authority of the Authority to determine. Until otherwise directed by the judiciary, the Authority is to presume that its organic act is constitutional, including §1.34(c). The mission of the Authority is to faithfully implement the Act and not second-guess the legality of the Legislature's actions. The Authority will reserve that function to the courts where it appropriately lies. Relative to the conclusions contained in the rules assessment documents of the Authority, these documents are designed to aid the Authority in its decision-making process related to its rules adoption. The comments or conclusions in these assessments cannot provide a basis for the Authority to fail to implement a legislative mandate in its organic act. These assessments simply provide to the Authority additional information as to what may be the impacts to be expected in the implementation of the Act. Finally, the Authority declines to seek Attorney General guidance on this issue because this will only delay the implementation of the transfer rules, and yet, provide no definite resolution of the matter which can only be given by the courts. The Authority's duty is to interpret the Act through its implementation rules, which will then provide the basis for any challenge to the Authority's interpretation of the Act then may ensue. In light of the above, the Authority has not modified §§711.324 and 711.338.

Section 711.328:

Public Comment No. 5:

SAWS asserts that §711.328(c) is confusing and contradictory to other provisions. According to SAWS, water rights are conveyed through the ownership of wells. The provisions as written would require an elaborate mechanism for tracking the future ownership of land irrigated during the historical period. Therefore, SAWS requests the deletion of §711.328(c).

Authority Response:

The Authority received the above-referenced comment and disagrees with it in part, and agrees with it in part. The basis for this determination is that §711.328(c) clearly provides that if the place of use of an IRP for irrigation purposes is conveyed to a third-party transferee, then the third-party transferee will also transferal of ownership of BIG associated with the irrigation IRP that is appurtenant to the original place of use. The lack of clarity surrounds the issue of whether irrigated lands that may be recognized as the place of use in an original IRP are owned by the owner of the IRP, or merely leased. The rule has been modified to clarify that the appurtenancy of BIG applies to irrigated land owned by the owner of the IRP. The Authority is not aware of any other provisions of its transfer rules that this rule contradicts, nor does SAWS identify any such rules in its comments. Additionally, under the Authority's system of transfer for groundwater withdrawal permits provided in subchapter L, and contrary to the assertion of SAWS, IRPs may now be conveyed irrespective of the ownership of the point of diversion or place of use. *See* proposed §711.328(a). The only exception to this rule is the non-transferability of BIG from the place of use in the original IRP for irrigation purposes that is owned by the owner of the IRP. As for the creation of an "elaborate mechanism for tracking the future ownership of land irrigated during the historical period" the Authority notes that before any transfer is effective it must have been filed with and approved by the Authority. See proposed §711.358. Moreover, all transfers are required to be recorded in the deed records of the appropriate county. *See* proposed §711.356. Accordingly, the Authority has made modifications to proposed §711.328(c) as set out in the final rules below.

Public Comment No. 6:

FLB argues that §711.328(c) and (e) exceed the scope of authority permitted to the Authority by the Legislature. According to FLB, the Legislature intended to provide for the transfer of BIG to different locations. FLB seeks the deletions of §711.328(c) and (e). FLB also submits that §711.328(d) should be revised as follows:

(d) in a transfer of the ownership of the place of use or point of withdrawal identified in an initial regular permit, the ownership of all or part of the initial regular permit issued for irrigation ground water may be reserved to the transferor.

Authority Response:

The Authority received the above-referenced comment and disagrees with it. The basis for this determination is that the Authority has the statutory authority and duty to restrict the transfer of the place and purpose of use of an IRP for irrigation purposes pursuant to §1.34(c) of the Act. In addition, amending §711.328(d) to allow the reservation of the ownership of BIG in the transferor would be inconsistent with §1.34(c) of the Act. Accordingly, the Authority has not made modifications to proposed §711.328.

Section 711.332: Public Comment No. 7:

Kosub questions why §711.332(b) places time limits on transfers of regular permits. Authority Response:

The Authority received the above-referenced comment and disagrees with the comment to the extent that the comments recommends that the proposed rules be amended (which it does not so request). The commenter seems to be seeking a clarification of the intent of the rule. The basis for this determination is that the a regular permit may be transferred for a defined period of time under a lease, or permanently under a sale. This proposed rule accounts for both situations. The term may in fact be perpetual. Accordingly, the Authority has not made modifications to proposed §711.332.

Section 711.336:

Public Comment No. 8:

FLB explains that it has no objection to §711.336 if their revisions, proposed under §§711.328 and 711.342, are adopted.

Authority Response:

The Authority received the above-referenced comment and disagrees with it. The basis for this determination is as set out in the Authority's response to Public Comment No. 6. Accordingly, the Authority has not made modifications to proposed §711.336.

Section 711.338:

Public Comment No. 9:

FLB asserts §711.338 exceeds the scope of authority, permitted to the Authority, by the Legislature. The commenter maintains that the Legislature intended that all irrigation groundwater be transferrable and suggests the following revisions:

Except as provided in §711.324(b) of this Chapter (relating to prohibited transfers), without restriction as to the place of use, a permittee may transfer all or part of a Regular Permit issued for base irrigation groundwater, provided that the purpose of use of the base water transferred is limited to irrigation use.

Authority Response:

The Authority received the above-referenced comment and agrees with the recommended change in part, although it disagrees with the rationale of the commenter. The basis for this determination is same as the Authority's response to Public Comment No. 3. In light of the above, the Authority has modified §711.338 accordingly, as set out below in the final rules.

Section 711.342(a)(4)

Public Comment No. 10:

NBU comments that this rule allows for the transfer of BIG only if BIG is converted to restricted irrigation groundwater which is physically impossible to use at both the place of use and the purpose of use for which it was permitted. NBU asks whether BIG is transferrable if the property is developed, serviced by a municipality, and no longer able to be farmed. On the other hand, if the owner of a piece of property sells it for development, can he also transfer BIG to a municipality, for municipal purposes, in exchange for municipal water service to the land to be developed? NBU generally asserts the phrase "physically impossible," is too restrictive and suggests replacing the term with "will not be" placed to a beneficial use at the place and purpose of use "due to a change in the intended use of the property."

SAWS suggests deleting the phrase "physically impossible" from §711.342(a)(4) and replacing it with a less restrictive term, although the commenter provides no guidance on their views of what the less restrictive language might be.

In reference to §711.342(b)(4), SAWS contends that because the installation of conservation equipment may not result in the conservation of groundwater, the effect of conservation practices should not be excluded from §711.342(b)(4). SAWS requests the following changes:

(b)(4) groundwater from the aquifer will be conserved with the *implementation of irrigation best management practices, as outlined in the Authority's Groundwater Conservation Plan or* the installation of water conservation equipment.

Selma remarks that the proposed rules does not provide a definition for the term "physical impossibility" and seeks clarification of the rule in relation to land irrigated during the historical period and presently being converted to industrial and municipal uses.

Also, the commenter asks the Authority to clarify at what point in the development process will the Authority consider irrigation use "physically impossible." Selma suggests modifying the proposed rule so that irrigation is deemed "physically impossible" when: (1) the plat is approved by the City (Selma), (2) Selma receives applications for building permits of any type from the developer; or (3) building permits are issued by Selma for the land.

Authority Response:

The Authority received the above-referenced comments and disagrees with them to the extent they request that the physical impossibility standard be relaxed and the installation of conservation equipment be modified. However, to the extent these comments request that the physical impossibility be clarified to reflect the intent of the Authority in proposing a physically impossible standard, the Authority agrees with the comments. The basis for this determination is as partially set out in the Authority's response to Public Comment No. 1. Basically, the intent of the 'physically impossible' standard was to provide the basis for the Authority to determine that the owner of the irrigated land had made an irretrievable land use decision to develop the lands from irrigated agriculture to a municipal or industrial use. Thus, the market would have dictated that these lands are no longer required for irrigated agriculture. Then logically, if the lands are no longer required for irrigated agriculture, the water appurtenant thereto is no longer required to support irrigated agriculture at this site. Because the Authority intended that 'physically impossible' equate to irretrievable change in land use, the Authority has modified the rule to clearly provide for this concept. The modification provides that if the land use at the site of the irrigated lands has changed such that the site no longer can qualify for an agricultural land use exemption, then BIG may be converted to UIG under §711.340.

Additionally, by way of explanation, BIG may be transferred if it is converted to either UIG. UIG is freely transferrable as to another place and purpose of use. See proposed §711.336.

NBU also inquires whether BIG is transferrable if the place of use is developed, serviced by a municipality and no longer able to be farmed. As long as the place of use is developed in such a way to lose its agriculture use property tax reduction, for example, by the construction of a housing subdivision, shopping mall, apartment complex, etc., then the Authority will consider the conversion criteria to have been satisfied. However, the mere transfer of ownership to a developer without attendant land use changes such that the land no longer can qualify for the property tax reduction, would not provide the basis for a conversion of BIG to UIG. The possibility of the land being transferred from the developer to a third-party due to future market conditions or other contingencies would yet remain. However, once the developer had constructed the improvements on the place of use such that the tax reduction is lost, then BIG could be converted to UIG. Concerning Selma's suggestion to modify the proposed rule so that irrigation is deemed "physically impossible" when plat approval has occurred, applications for building permits are received, and building permits are issued, the Authority is of the view that all of these acts, if they occur, and are followed up by actual improvements on the land will, lead to the determination that the land can not qualify for the agricultural land tax reduction. However, the Authority does not find that the rule requires modification to account for these acts. The development of irrigation land is a long process that culminates in the construction of improvements on the land, and thereby at the end of the process eventually renders the property ineligible for the tax exemption. Accordingly, the Authority has made modifications to proposed §711.342 as set out in the final rules below.

Section 711.344

Public Comment No. 11:

Verstuyft commented on the transfer rules. As proposed, the rules provide for the conversion of BIG to RIG. After such a conversion, the place of use can be changed to any other place in the county and the purpose of use may also be changed. The commenter proposes the rules be modified to allow water to be transferred out of the county. She further states that the rules should provide for the transfer of BIG.

Selma suggests replacing the language "within the same county as the place of use identified in the IRP" with "within the Authority's area." According to Selma, the restriction limiting transfers to uses within the same county is groundless. Selma suggests adopting either of the following revisions:

1) Add a sentence at the end of §711.344 to read as follows:

Notwithstanding the above, if a permittee transfers use of all or part of an initial regular permit for irrigation purposes converted to restricted irrigation groundwater to a municipally-owned utility with a certificate of convenience and necessity, the municipally-owned utility may use the water at any place within it certificated area.

2) Rewrite §711.344 to read as follows:

A permittee may transfer the place or purpose of use of all or part of an initial regular permit for irrigation purposes converted to restricted irrigation groundwater to another place or purpose of use, so long as the transferee uses all or part of the water within the same county as the place of use identified in the initial regular permit.

Authority's Response:

The Authority received the above-referenced comments and agrees with them in part, while disagreeing with the rationale. The basis for this determination is that §1.34(c) evidences the intent of the Legislature to reserve a base amount of groundwater for irrigated agricultural. However, this section does not otherwise indicate a geographic preference within the jurisdiction of the Authority for irrigation purposes. Moreover, the Legislature's intent to reserve an amount of groundwater for irrigation, due to the reference to "original" IRP in §1.34(c), seems to be limited to irrigation that existed during the historical period upon which the original IRPs where based. The Legislature did not seem to contemplate or provide for the circumstance when the original irrigated lands would be subsequently developed such that the appurtenancy of irrigation use provided for in the second sentence of §1.34(c) would be rendered without meaning because the land use at the site of the original irrigated lands was no longer susceptible to irrigation. In light of the above, the Authority has made modifications to proposed §711.344 to delete the county-of-origin and purpose of use limitations. With the elimination of these limitations on place and purpose of use, after conversion, restricted irrigation groundwater becomes indistinguishable from UIG. Therefore, §711.344 is longer required and has been withdrawn and will not be adopted. Moreover, all references to "restricted irrigation groundwater" have been deleted from the rules and replaced with UIG, as appropriate, in §§711.320(1)(B), 711.340, and 711.342(a) and

(b) (formerly 711.342(c)). The modifications are set out below in the final rules.

Section 711.352:

Public Comment No. 12:

Schertz opposes adopting §711.352 because: (1) it purportedly arbitrarily restricts the normal and anticipated growth of the city of Schertz, and (2) the modifiers in §77.352(5)(B) are meaningless. Schertz asserts it must be able to use water east, which is drawn from wells west of Cibolo Creek, if it wants to maintain orderly growth. However, to obtain a permit for the transfer of water from west to east, the city would have to establish that aquatic life, wildlife, and endangered species will be protected. The springflows of the Comal and San Marcos Springs must also be maintained. Schertz contends that it knows of no recognized scientific method that would correlate this kind of water transfer to the protection of the interests described above. Therefore, the city argues that application for such a transfer is impossible. Selma maintains that additional rules for transferring water across Cibolo Creek causes increased difficulty in procuring Edwards water to serve customers economically. Selma requests amending §711.352(5)(B) so that the rule does not apply to municipalities providing municipal water service to certificated areas located on both sides of Cibolo Creek.

Authority Response:

The Authority received the above-referenced comments and disagrees with them. The basis for this determination is that the potential concentration of points of withdrawal closer to the orifices of Comal and San Marcos Springs may jeopardize the springflow protection programs of the Authority. Therefore, it is reasonable for the Authority to require additional evidentiary proof on issues that bear on the potential effect of transfers of points of withdrawal on springflows that the Authority has a statutory duty to maintain as may be required by federal or state law. This is the primary regulatory objective of the transfer regulation set forth in §711.352(5)(B). To create exceptions for certain water users with certain places of use, as suggested by the commenters, may potentially diminish the Authority's springflow protection program effectiveness if the points of withdrawal supplying the places of use are nonetheless concentrated to negatively affect springflow.

Relative to the argument that there is no recognized scientific method that would correlate transfers to the protection of the springflows, the commenter is under the misinterpretation that §711.352(5)(B) applies to the transfer of places of use, which it does not. This section only applies to transfers of points of withdrawal.

Section 711.356:

Public Comment No. 13:

SAWS maintains that recordation of IRPs may also include intermediate counties if a previous transfer in other than the county of origin has occurred. As a result, SAWS asserts that the Authority should require recording of all transfers so that a chain of title can be readily established and the title insurance issued.

Authority Response:

The Authority received the above-referenced comment and agrees with it although no change is required to be made to the rule. The basis for this determination is that §711.356 as written already requires all transfers to be recorded in the counties where the place of use or point of withdrawal is located. These places of recordation, in addition to the central transfer records of the Authority, will provide an adequate procedure to produce a complete chain of title for all transfers of IRPs. In light of the above, the Authority has not made modifications to proposed §711.356.

Section 711.364:

Public Comment No. 14:

SAWS contends the Authority's general manager should be required to report the effect of all transfers and requests the following changes to §711.364:

The general manager shall monitor the impact resulting from transfers issued pursuant to §711.352 of this title (relating to...
.

Authority Response:

The Authority received the above-referenced comment and agrees with it. The basis for this determination is that the purpose of the transfer monitoring report in §711.364 is to provide information for the Authority to determine if there is a need to modify its transfer application processing procedures in order to better to support its springflow protection programs as may be required by federal or state law. This information acquisition objective generally applies irrespective of the nature of the transfer. In light of the above, the Authority has made modifications to proposed §711.364 accordingly, as set out below in the final rules.

General Comments:

Public Comment No. 15:

Archer commented on the right to transfer the purpose of use from irrigation to municipal uses. He suggests the rules be more strict and have some controls in place as to the amount of water being transferred out of irrigation.

Authority Response:

The Authority received the above-referenced comment and disagrees with it. The basis for this determination is that §1.34 of the Act basically governs the transfer restrictions that apply to IRPs for irrigation purposes. The objective of the Authority is to implement §1.34 through its rules in a way that effectuates the intent of the Legislature. The primary irrigation transfer restriction established by the Legislature is contained in §1.34(c) of the Act which limits the transferability of the BIG in certain circumstances. The Authority has drafted its transfer rules to implement this restriction. The Authority defers to the Legislature in its determination that the irrigation transfer restrictions in §1.34(c) are sufficient to accomplish the objectives of the Legislature in passing the Act. In light of the above, the Authority has not made other modifications to the proposed rules in subchapter L of chapter 711, relating to transfers.

Public Comment No. 16:

Verstuyft comments on the Local Employment Impact Statement ("LEIS") as it relates to rural counties. She believes land that is not irrigated will be less valuable than if it was irrigated, which in turn will reduce the tax base, especially in small rural counties. Ms. Verstuyft comments that the statement should show a greater impact on the small school districts and small tax base counties who will be hurt by the removal of agriculture from the tax base.

Authority's Response:

The Authority received the above-referenced comment and disagrees with it. The basis for this determination is that under §2001.022, TEXAS GOVERNMENT CODE, at the request of agencies engaging in proposed rulemaking, a LEIS may be prepared by the Texas Workforce Commission ("TWC") in connection with certain proposed rules. If the TWC does not prepare an LEIS (as was the case for these rules), §2001.022(e) creates a presumption that the proposed rules do not affect local employment. The requesting agency does not determine if the TWC will prepare an LEIS, or the contents thereof. Thus, the Authority has no control over the content of an LEIS prepared by the TWC. The Authority is, however, required to report in its notices of proposed rules the LEIS, if any, prepared by the TWC, which the Authority did in this case. In light of the above, the Authority has not made modifications to the LEIS.

Public Comment No. 17:

TFB maintains that a takings impact statement ("TIA") was required before the Authority provided public notice of the proposed rules. According to TFB, the Texas Private Real Property Rights Preservation Act ("Property Rights Act") does not excuse the Authority from the requirements of the Property Right Act because the rights are not "vested" or because the Legislature has chosen to regulate those property rights. Furthermore, the TFB contends that property does not have to be vested to come within the purview of the Property Rights Act and, nonetheless, groundwater rights are vested rights requiring no perfection because they accompany the surface estate.

Authority's Response:

The Authority has received this comment and disagrees with it. Chapter 2007 of the Texas Government Code, the Property Rights Act (Texas Private Real Property Rights Preservation Act) referred to by the TFB, requires governmental entities, under certain circumstances, to prepare a takings impact assessment ("TIA") in connection with certain covered categories of proposed governmental actions. Based on the following reasons, the Authority has determined that it need not prepare a TIA in connection with the adoption of these rules.

First, the Authority has made a "categorical determination" that these proposed Chapter 711 Subchapter L rules do not affect "private real property" as that term is defined in the Texas Private Real Property Rights Preservation Act. The rules implement portions of the Act intended to place limits on the ability to transfer permits or interim authorization status. These permit and interim authorization interests are issued by the Authority and derive not from the common law, but from a statute -- the Act. Thus, they are not an "interest in real property recognized by the common law," and the regulating of transfers of permits or interim authorization status does not affect private real property.

Second, the Authority's action in adopting these rules is an action that is reasonably taken to fulfill an obligation mandated by state law and is thus excluded from the Texas Private Real Property Rights Preservation Act under §2007.003(b)(4) of the Texas Government Code. *See* §§1.08(a), 1.11(a), (b) and (h), 1.15(a), 1.17(a), 1.22(a)(1), 1.24(c), 1.28(b), and 1.34 of the Act.

This conclusion is supported by the decision in *Edwards Aquifer Authority v. Bragg*, 21 S.W.3d 375 (Tex. App.-San Antonio 2000, pet. denied) ("*EAA v. Bragg*"). In that case, the Plaintiffs sued to invalidate a set of rules adopted by the Authority which were designed to implement the Authority's permitting program. The Fourth Court of Appeals held that the Authority's adoption of its permit rules was expressly mandated by the Act and was therefore excepted from the operation of TPRPRPA. *Id.* at 379-80. The reasoning in that case applies here.

Third, it is the position of the Authority that all valid actions of the Authority are excluded from the Texas Private Real Property Rights Preservation Act under §2007.003(b)(11)(C) of the Texas Government Code as actions of a political subdivision taken under its statutory authority to prevent waste or protect the rights of owners of interest in groundwater.

Accordingly, for the reasons stated above, a TIA need not be performed in connection with the adoption of these rules.

Section 2001.0225 of the Texas Government Code requires an agency to perform, under certain circumstances, a regulatory analysis of "major environmental rules." The Authority has determined that these final rules are not "major environmental rules" as that term defined by §2001.0225(g)(3) of the Texas Government Code. The basis for this determination is that the final rules do not have the specific intent to "protect the environment" or "reduce risks to human health from environmental exposure." The Act requires the Authority to implement a permitting system. Prior to the issuance of these permits, the Act calls for an "interim authorization" period during which certain existing users may continue to withdraw and use aquifer water. The Act calls for a system whereby all or parts of these withdrawal permits and interim authorization status may be sold, leased, or otherwise transferred. The final Chapter 711 Subchapter L rules set forth the criteria and procedures by which permits or interim authorization status could be transferred. The Subchapter L rules are integral parts of a conventional water law-based regulatory program. The specific intent of Subchapter L is to encourage the marketing of permits and interim authorization status as commodities to transfer groundwater to the highest and best use within the jurisdiction of the Authority. The Authority has determined that only §711.352 has a specific intent to protect the environment and, therefore, might qualify as a MER if the other criteria for a MER which are set out in §2001.0225(g)(3) are satisfied. None of the other sections within Subchapter L have the specific intent to protect the environment or reduce risks to human health from environmental exposure and, therefore, they are not MERs.

However, without determining whether §711.352 constitutes a MER, the Authority has concluded that no RIAMER need be prepared for any of the Subchapter L rules because none of them meet any of the criteria listed in APA §2001.0225(a)(1)-(4). First, the Subchapter L rules do not exceed a standard set by federal law. The only reasonably related federal law establishes the Sole Source Aquifer Program implemented by the EPA. There is no federal law that specifically requires permitting or interim authorization status for withdrawals of Edwards Aquifer groundwater, or rules and procedures for the transfer of such interests. Therefore, the Subchapter L rules do not exceed a standard set by federal law. Moreover, even if the rules did exceed a standard set by federal law, the rules are specifically required by the Act, a state law which requires the Authority to, among other things: manage, conserve, preserve, and protect the aquifer; adopt rules to carry out its powers and duties under the Act; regulate permits, manage withdrawals and points of withdrawals from the aquifer; require various types of permits for certain withdrawals; allow for interim authorization withdrawals prior to permit issuance; require transfer to the Authority of a portion of permits for water conserved through conservation projects; limit transport of water out of Medina and Uvalde Counties; and regulate transfers of permits and interim authorization status (pursuant to, *inter* *alia*, §§1.08(a), 1.11(a), (b) and (h), 1.15(a), 1.17(a), 1.22(a)(1), 1.24(c), 1.28(b) and 1.34 of the Act).

Second, the final Subchapter L rules do not exceed an express requirement of state law. Instead, the final rules are designed to carry out the Authority's statutory responsibility to: manage, conserve, preserve and protect the aquifer, adopt rules to carry out its powers and duties under the Act, to regulate permits, manage withdrawal, and points of withdrawals from the aquifer, require various types of permits for certain withdrawals, allow for interim authorization withdrawals prior to permit issuance, require transfer to the Authority of a portion of permits and interim authorization status for water conserved through conservation projects, limit transport of water out of Medina and Uvalde Counties, and regulate transfers of permits (pursuant to, *inter alia*, §§1.08(a), 1.11(a), (b) and (h), 1.15(a), 1.17(a), 1.22(a)(1), 1.24(c), 1.28(b), 1.34 of the Act). The final rules are designed to comply with these express requirements of state law and not exceed them. Other than the Act, there are no other "express requirements of state law" which are applicable to these final rules or which could be exceeded by these final rules.

Third, the final Subchapter L rules do not exceed a requirement of a delegation agreement or contract between the State of Texas and an agency or representative of the federal government to implement a state and federal program. The subject matter of the final rules is not covered by any delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program.

Fourth, the final Subchapter L rules will not be adopted solely under the general powers of the Authority instead of under a specific state law. While these final rules are adopted in part under the Authority's general powers, they are also adopted under the Act, a specific state law regarding the Edwards Aquifer. In particular, the rules are adopted pursuant to, *inter alia*, §§1.08(a), 1.11(a), (b), (c), and (h), 1.15(a), 1.17(a), 1.22(a)(1), 1.24(c), 1.28(b), and 1.34 of the Act, which require the Authority to, among other things: manage, conserve, preserve and protect the aquifer; adopt rules to carry out its powers and duties under the Act; to regulate permits, manage withdrawals and points of withdrawals from the aquifer; require various types of permits for certain withdrawals; allow for interim authorization withdrawals prior to permit issuance; require transfer to the Authority of a portion of permits or interim authorization status for water conserved through conservation projects; limit transport of water out of Medina and Uvalde Counties; and regulate transfers of aquifer rights.

For these reasons, it is not necessary to perform a RIAMER on the final Subchapter L rules.

These final Chapter 711 Subchapter L rules are adopted pursuant to §§1.08(a), 1.11(a), (b) and (h), 1.15(a), 1.17(a), 1.22(a)(1), 1.24(c), 1.28(b), and 1.34 of the Act.

Section 1.08(a) of the Act provides that the Authority "has all of the powers, rights, and privileges necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer." The Authority interprets this section to provide the Authority with broad and general powers to take actions as necessary to manage the aquifer, among other things, including the implementation of a permit and interim authorization transfer program.

Section 1.11(a) of the Act provides that the Board of Directors ("Board") of the Authority "shall adopt rules necessary to carry out the authority's powers and duties under (Article 1 of the Act), including rule governing procedures of the board and the authority." The Authority interprets this section to provide broad rulemaking authority to implement the various substantive and procedural groundwater resource management programs set forth in the Act, related to, among other things, including the transfer program.

Section 1.11(b) of the Act requires the Authority to "ensure compliance with permitting, metering, and reporting requirements and . . . regulate permits." The Authority interprets this section, in conjunction with §1.11(a) and (h) and §1.34 of the Act, and §2001.004(1) of the APA, to require that the Authority adopt and enforce transfer rules.

Section 1.11(h) of the Act provides, among other things, that the Authority is "subject to" the APA. The Authority interprets this section to provide that the Authority is required to comply with the APA for its rulemaking related to transfers, even though the Authority is a political subdivision and not a state agency that would generally be subject to APA requirements.

Section 1.15(a) of the Act directs the Authority to manage withdrawals from the Aquifer and manage all withdrawal points from the Aquifer as provided by the Act. The Authority interprets this section to authorize the management of withdrawals pursuant to transfers and the transfer of points of withdrawal.

Section 1.17(a) of the Act provides that a person who, on the effective date of this article, owns a producing well that withdraws water from the aquifer may continue to withdraw and beneficially use water without waste until final action on permits by the Authority, if: (1) the well is in compliance with all statutes and rules relating to well construction, approval, location, spacing, and operation; and (2) by March 1, 1994, (changed to December 28, 1996 by the Texas Supreme Court in *Barshop v. Medina Under. Water Cons. Dist.*, 925 S.W.618 (Tex. 1996)) the person files a declaration of historical use on a form as required by the Authority. Section 1.17(d) provides for the termination of interim authorization status. The Authority interprets these subsection as setting the start and end points for the terms of transfers of interim authorization status that may occur.

Section 1.22(a)(1) of the Act provides that the Authority may acquire groundwater withdrawal permit to be used for: holding in trust for sale or transfer to other users; holding in trust as a means of managing aquifer demand; holding for resale or retirement as a means of achieving pumping reductions required by the Act; or retiring the rights. The Authority interprets this section as authorizing the Authority to be a transferee of groundwater withdrawal permits or interim authorization status.

Section 1.24(c) allows the Authority to, among other things, issue a grant for a water conservation, reuse or management project and, in exchange, require the grant beneficiary to transfer to the Authority groundwater withdrawal permit Aquifer water equal to a portion of the water conserved or made available by the project. The Authority interprets this section as authorizing the Authority to be a transferee of groundwater withdrawal permits or interim authorization status.

Section 1.28(b) of the Act, in part, generally prohibits the transport of groundwater out of Uvalde County or Medina County. The Authority has not yet implemented this section of the Act through rulemaking.

Section 1.34 of the Act authorizes transfers and imposes certain limitations. The Authority interprets subsection (a) as authorizing the Authority to prohibit the place of use for Aquifer water to be outside the Authority's boundaries. Second, the Authority interprets subsection (b) to repudiate the common law rule against the beneficial use of conserved water and allow the Authority to establish rules by which a person may install water conservation equipment and sell the water conserved. Third, the Authority interprets the first sentence of subsection (c) to provide that the owner of an initial regular permit for irrigation use may transfer the place or purpose of not to exceed 50 percent of the groundwater withdrawal amount recognized in the original initial regular permit to any other place of use. The Authority also interprets the second sentence of subsection (c) to provide that the owner of an initial regular permit for irrigation use may not, absent extraordinary circumstances, transfer the place or purpose of use for the remaining 50 percent of the groundwater withdrawal amount to any other place of use, and that this amount becomes appurtenant to the irrigated lands (place of use) owned by the owner of the original initial regular permit and identified as such place of use in the permit.

§711.320. Definitions.

The following words and terms, when used in this subchapter, shall have the following meanings, unless the context clearly indicates otherwise:

(1) base irrigation groundwater--The 50 percent portion, in acre-feet per annum, of the:

(A) groundwater withdrawal amounts identified in §711.176 of this chapter (relating to Groundwater Withdrawal Amount of Initial Regular Permits: Compensation for Step-Up Amounts) for an initial regular permit; or

(B) section 4B amount in a declaration, for interim authorization status, for irrigation purposes; which, unless converted to unrestricted groundwater pursuant to §711.340 of this Chapter (relating to Conversion of Base Irrigation Groundwater), must be used in accordance with the original initial regular permit and must pass with transfer of the ownership of the irrigated lands owned by the holder of the initial regular permit and identified as the place of use in such permit.

(2) groundwater withdrawal amount--The amount of groundwater from the aquifer, in acre-feet per annum, which is authorized to be withdrawn under a regular permit issued by the board, or pursuant to interim authorization status, under §711.70 of this title (relating to Interim Authorization Groundwater Withdrawal Amounts).

(3) transfer--A change in a regular permit, or application for regular permit, as follows:

(A) ownership;

(B) the person authorized to exercise the right to make withdrawals and place to beneficial use;

(C) point(s) of withdrawal;

(D) purpose of use;

(E) place of use; or

(F) maximum rate of withdrawal.

(4) unrestricted irrigation groundwater--The groundwater withdrawal amount for an initial regular permit, or interim authorization status, for irrigation purposes which is not base irrigation groundwater.

(5) water conservation equipment--Any physical device the installation and operation of which results in less groundwater from the aquifer being required for irrigation purposes at the place of use identified in a regular permit, or an application for regular permit.

§711.322. Applicability.

(a) This subchapter applies to transfers of the following:

(1) applications for initial regular permits;

(2) interim authorization status associated with applications for initial regular permits; and

(3) initial regular, additional regular, term, emergency, monitoring well, and recharge recovery permits.

(b) This subchapter does not apply to the:

(1) wholesale or retail sale of groundwater on a commodity basis to a person under a utility service contract, water supply contract, or similar document, unless the implementation of the contract results in a transfer;

(2) retirements of regular permits by the Authority; or

(3) suspension of withdrawals under Subchapter D (relating to Demand Management) of chapter 715 (related to Comprehensive Water Management Plan Implementation).

§711.324. Prohibited Transfers.

(a) Term, emergency, and monitoring well permits, and exempt well status are not transferable except for ownership,

(b) The place of use for any permit or interim authorization status may not be transferred to a place of use located outside of the boundaries of the Authority.

(c) Except as provided in §711.338 of this chapter (relating to Transfer of Base Irrigation Groundwater), the place or purpose of use for all or part of the base irrigation groundwater component of either an initial regular permit or interim authorization status is not transferrable.

§711.326. Recharge Recovery Permits.

Recharge recovery permits are transferrable only as to ownership, purpose of use, and place of use. Transfers of the point of withdrawal of a recharge recovery permit may be made by filing an application to amend a recharge recovery permit.

§711.328. Transfer of Ownership.

(a) Except as provided in subsections (c) and (e), the ownership of a regular permit may be transferred separately from the ownership of a place of use or point of withdrawal.

(b) Absent an express reservation of rights in the transferor, the transfer of ownership of the place of use or point of withdrawal for a regular permit is presumed to transfer ownership of the regular permit.

(c) The ownership of all or part of an initial regular permit issued for base irrigation groundwater shall pass with the transfer of ownership of the irrigated lands owned by the holder of the initial regular permit and identified as the place of use in such permit.

(d) In a transfer of the ownership of the place of use or point of withdrawal identified in an initial regular permit, the ownership of all or part of the initial regular permit issued for unrestricted irrigation groundwater may be reserved to the transferor.

(e) In a transfer of the ownership of the place of use or point of withdrawal identified in an initial regular permit, the ownership of all or part of the initial regular permit issued for base irrigation groundwater may not be reserved to the transferor.

§711.338. Transfer of Base Irrigation Groundwater.

(a) Except as provided in subsection (b), a permittee may not transfer the place or purpose of use for all or part of an initial regular permit issued for base irrigation groundwater.

(b) A permittee may temporarily transfer the place of use for all or part of an initial regular permit issued for base irrigation groundwater to another place of use owned by the permittee. Such a temporary transfer becomes void if the permittee subsequently transfers the ownership of the place of use of the initial regular permit. Section 711.328 (c) of this chapter (relating to Transfer of Ownership) would then controls, and the base irrigation groundwater shall pass with the transfer of ownership of the irrigated lands identified as the place of use in the initial regular permit.

§711.342. Basis for Granting Applications to Convert Base Irrigation Groundwater.

(a) The board shall grant an application to convert base irrigation groundwater to unrestricted irrigation groundwater if it finds that:

(1) the application complies with the Act and the Authority rules;

(2) all applicable fees have been paid; and

(3) all applicable reports have been filed; and either

(4) the land use for the irrigated lands identified as the place of use in an original initial regular permit is changed such that the irrigated lands can no longer qualify for an agricultural land ad valorem property tax reduction established by §23.55, TEXAS TAX CODE; or

(5) groundwater from the aquifer will be conserved after the installation of water conservation equipment.

(b) No transfer of base irrigation groundwater applied to be converted to unrestricted irrigation groundwater is effective until the board issues a final order granting an application to convert base irrigation groundwater.

§711.352. Basis for Granting Applications to Transfer and Amend.

The board, or, if delegated, the general manager, shall grant an application to transfer and amend a regular permit, or an application for a regular permit, if it finds that:

(1) the application complies with the Act and the Authority's rules;

(2) the application complies with the Authority's comprehensive management plan;

(3) all applicable fees have been paid;

(4) all applicable reports have been filed; and

(5) the point of withdrawal of a regular permit is either:

(A) not transferred from a point located west of Cibolo Creek to east of Cibolo Creek; or

(B) transferred from a point located west of Cibolo Creek to east of Cibolo Creek, and

(i) aquatic and wildlife habitat will be protected;

(ii) species that are designated as threatened or endangered under applicable federal and state law will be protected;

(iii) springflows of Comal Springs and San Marcos springs will not be affected during critical drought conditions; and

(iv) continuous minimum springflows of the Comal Springs and San Marcos Springs will be maintained to protect endangered and threatened species to the extent required by federal law.

§711.364. Transfer Impact Monitoring Report.

The general manager shall monitor the impact resulting from transfers issued pursuant to §711.352 of this title (relating to Basis for Granting Application to Transfer and Amend). Not later than two years from the effective date of these rules, the general manager shall prepare a report to the board making findings and recommendations concerning such impacts.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009050
Gregory M. Ellis
General Manager
Edwards Aquifer Authority
Effective date: January 17, 2001
Proposal publication date: September 29, 2000
For further information, please call: (210) 222-2204

♦ ♦ ♦

SUBCHAPTER M. METERS; ALTERNATE MEASURING METHODS; AND REPORTING

31 TAC §§711.400, 711.402, 711.404, 711.406, 711.408, 711.410, 711.412, 711.414, 711.416, 711.418, 711.420

The Edwards Aquifer Authority (the "Authority") adopts new 31 TAC §§711.400, 711.402, 711.404, 711.406, 711.408, 711.410, 711.412, 711.414, 711.416, 711.418, and 711.420 (the "Chapter 711 Subchapter M" or "Subchapter M" rules) relating to meters, alternative measuring methods and reporting. Sections 711.402, 711.404, 711.406, 711.410, 711.412, 711.414, and 711.416 are adopted with changes to the proposed text as published in the September 29, 2000 issue of the *Texas Register* (25 TexReg 9910) and are republished herein. Sections 711.400, 711.408, 711.418, and 711.420 are adopted without changes and will not be republished.

The Edwards Aquifer Authority Act, Act of May 30, 1993, 73rd Legislature, Regular Session, Chapter 626, 1993 TEXAS GENERAL LAWS 2350, as amended by Act of May 28, 1995, 74th Legislature, Regular Session, Chapter 3189, 1995 TEXAS GENERAL LAWS 2505, Act of May 16, 1995, 74th Legislature, Regular Session, Chapter 361, 1995 TEXAS GENERAL LAWS 3280, and Act of May 6, 1999, 76th Legislature, Regular Session, Chapter 163, 1999 TEXAS GENERAL LAWS 634 (the "Act"), requires the Authority to implement a permitting system whereby "existing users" of groundwater from the Edwards Aquifer and other potential users of aquifer water may apply for and receive permits issued by the Authority allowing for the withdrawal of groundwater from the aquifer. The Act acknowledges that this permitting and regulatory system cannot be accomplished effectively unless aquifer wells for which permits are required are metered or installed with alternative methods for measuring the rate and quantity of withdrawals, and the results are reported to the Authority.

The Subchapter M rules are adopted pursuant to §§1.08(a), 1.11(a), (b), (d)(2) and (h), 1.15(a), 1.31, 1.32, 1.33 and 1.36 of the Act and §§36.111, 36.123 and 49.221 of the Texas Water Code.

Section 1.08(a) of the Act provides that the Authority "has all of the powers, rights, and privileges necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer." This section provides the Authority with broad and general powers to take actions as necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer.

Section 1.11(a) of the Act provides that the Board of Directors ("Board") of the Authority "shall adopt rules necessary to carry out the authority's powers and duties under (Article 1 of the Act), including rules governing procedures of the board and the authority." This section provides broad rulemaking authority to implement the various substantive and procedural programs set forth in the Act related to the Edwards Aquifer, including the permitting program.

Section 1.11(b) of the Act requires the Authority to "ensure compliance with permitting, metering, and reporting requirements and . . . regulate permits." This section, in conjunction with §1.11(a) and (h) of the Act, and §2001.004(1) of the APA, requires the Authority to adopt and enforce the Chapter 711 rules.

Section 1.11(d)(2) of the Act empowers the Authority to enter into contracts. Pursuant to this section, the Authority may enter into contracts with well owners concerning meters and reimbursement for same under the Subchapter M rules.

Section 1.11(h) of the Act provides, among other things, that the Authority is "subject to" the APA. This section essentially provides that the Authority is required to comply with the APA for its rulemaking, even though the Authority is a political subdivision and not a state agency that would generally be subject to APA requirements.

Section 1.15(a) of the Act directs the Authority to manage withdrawals from the aquifer and manage all withdrawal points from the aquifer as provided by the Act. This section is implemented, in part, through the Chapter 711 Subchapter M rules.

Section 1.31 of the Act provides that nonexempt well owners must install and maintain meters or alternative measuring devices to measure the flow rate and cumulative amount of water withdrawn from each well. The section further provides that the Authority must pay for such meters on irrigation wells in existence on the effective date of the Act. These concepts are implemented in the Chapter 711 rules, primarily in Subchapter M.

Section 1.32 of the Act requires permittees to submit annual water use reports to the Authority. This section is implemented in Subchapter M.

Section 1.33 of the Act provides the criteria for exempt wells -- i.e., wells that produce no more than 25,000 gallons of water per day for domestic and livestock use and that are not within or serving a subdivision requiring platting. The section explains that such wells are exempt from metering requirements. However, such wells must be registered with the Authority. These concepts are implemented, in part, by the Chapter 711 Subchapter M rules.

Section 1.36 of the Act empowers the Authority to enter orders enforcing the terms and conditions of permits, orders, or rules, and to draft rules suspending permits for failure to pay required fees or violations of permits, orders or rules. These concepts are implemented, in part, by the Chapter 711 Subchapter M rules.

Chapter 36 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 36.111 requires the Authority to require aquifer users to keep and maintain reports of drilling, equipping, and completing water wells and the production and uses of groundwater. The Chapter 711 Subchapter M rules help implement these requirements.

Section 36.123 of the Texas Water Code empowers representatives of the Authority to enter land and perform tests and other inspections. The Chapter 711 Subchapter M rules help implement this authority.

Chapter 49 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 49.221 empowers representatives of the Authority to enter land and perform tests and other inspections. The Chapter 711 Subchapter M rules help implement this authority.

The Subchapter M Rules

Section 711.400 states the general applicability of Subchapter M, which provides and establishes requirements related to the metering or measuring of the amount of groundwater withdrawn from the Edwards Aquifer and the reporting of information which results from that metering to the Authority. Section 711.400 essentially reflects and reiterates the requirement stated in §1.31 of the Act, that the owner of a nonexempt well that withdraws water from the aquifer install and maintain a measuring device approved by the authority, and §1.33 of the Act which exempts certain wells from such metering requirements. These statutory requirements constitute the basis for §711.400.

Section 711.402 states the basic duty that well owners must install and operate a meter or approved alternative measuring device (AMD) to measure the flow rate and cumulative amount water withdrawn from the well. These requirements are derived directly from 1.31 of the Act. Section 711.402 also requires that a meter be installed within six months of the effective date of the rules but exempts the Authority's meters from this deadline. The Authority believes that six months provides a sufficient time for a meter to be installed. The exemption for meters that the Authority is required to install, is based on the fact that the Authority may be required to install over 600 meters on wells owned by others. Section 711.402 further specifies that the meters must be installed, operated, maintained, and repaired in accordance with the manufacturer's standards and shall ensure an error of not greater than plus or minus five percent. The Authority believes that requiring users to meet manufacturer's standards is the best way to insure that a meter will work property. Also, a five percent error is generally accepted in the context of flow measurement. Although new meters can normally achieve an accuracy rate of plus or minus two percent, maintaining such a level of accuracy is impracticable. Finally, this section, as modified, provides that permitted non-irrigation wells from which exempt withdrawals are allowed under §711.46(b) of the Authority's rules must be constructed so that permitted and exempt withdrawals are metered separately and not commingled. The basis for rule is to allow the Authority to assure compliance with the 25,000 gallons per day limitation for exempt withdrawals. For exempt wells, compliance with this limitation is assured by requiring that such wells be incapable of exceeding the 25,000 gallon per day limitation. The Authority cannot assure compliance with the 25,000 gallon per day limitation in the same manner with respect to exempt withdrawals allowed from permitted irrigation wells pursuant to §711.46(b). Therefore, in order to allow such withdrawals pursuant to §711.46(b), assure compliance with the 25,000 gallon per day limitation on exempt withdrawals, and to be able to accurately determine the amount of permitted withdrawals from such irrigation wells, the Authority requires that exempt withdrawals under such circumstances be metered separately and to prohibit commingling of the permitted and exempt withdrawals.

Section 711.404 states the general rule that the owner of the well shall be the person who is responsible for the installation, maintenance, operation and repair of the meter. The exception to this rule is for irrigation wells in existence on September 1, 1993. For such wells, the meter shall be installed and maintained by the Authority. In any event, the operation of a meter shall be the responsibility of the well owner. These provisions reflect and are mandated by §1.31 of the Act. §711.404 also provides that, for meters installed by the Authority on irrigation wells, if the well owner transfers any part of the purpose of use of the water from the well to a purpose other than irrigation, then the own must reimburse the Authority for all or a portion of the cost of the meter or install a replacement meter. The Authority believes that if a well formerly used for irrigation becomes, in whole or in part, a well used for a purpose other than irrigation, the protection offered by 1.31(b) of the Act should no longer apply to the extent that the well is used for the other purpose.

Section 711.406 provides that no meter may be installed or modified without first filing an application with the Authority and receiving written approval. The section also states the criteria by which the general manager shall judge the application. Among the criteria is the requirement that the meter have a certified error of not greater than plus or minus five percent. A five percent error is an accepted industry standard for municipal and industrial wells. According to the AWWA (American Water Works Association) Manual of Water Supply Practices, manufacturers of propeller type meters indicate that, with wear, a properly installed, properly functioning meter can be expected to have accuracy at this level. Another criteria is that the meter must meet AWWA standards for design, materials, and accuracy. AWWA standards are consistent with American National Standards Institute/National Sanitation Foundation (ANSI/NSF) Standard 61 and have been adopted by the Authority because AWWA and its members have extensively studied questions related to meter installation, maintenance and accuracy. Another criteria is that the meter must have a non-resettable totalizer. An non-resettable totalizer is necessary to keep the meter from being reset to zero. This is necessary to allow users to report and the Authority to monitor continuous total withdrawals. Another criteria is that the totalizing register of the meter must have the capacity to record the amount of groundwater withdrawn in a year. Groundwater must be reported on an annual basis. Meter "roll-over" can cause reporting errors on annual reporting. The section also requires that notice be given to the Authority within five days after the installation or modification of a meter so that the Authority can perform an inspection. The Authority must be able to determine, as soon as possible, whether installation is proper in order to insure that the meter is properly measuring flow.

Section 711.408 requires users with existing meters to register their meters with the Authority within six months of the effective date of these rules. The section also provides that meters will be approved if they meet the criteria in §711.406(b), which are also the criteria that apply to new meters. The Authority believes that all meters, new and existing, should be required to meet the same criteria. Section 711.408 also allows owners of certain irrigation wells who have paid for the installation of a meter to request reimbursement from the Authority. The Authority believes that this provision implements the intent behind §1.31(b) of the Act and provides the Authority with a more economical option than purchasing and installing all new meters.

Section 711.410 requires the owner of a well who believes that his or her meter may be inaccurate to notify the Authority of this fact within seven days. The Authority may then inspect and require testing of the meter and take corrective action. The Authority believes that this requirement is necessary in order to insure that meters maintain their accuracy.

Section 711.412 prohibits well owners from removing or disabling a meter without first providing notice to the Authority. The section also requires approval of the Authority prior to such activities, except for routine maintenance. The Authority believes that it must be kept apprized, for accounting purposes, of the instances that meters are removed or disabled. The section also generally prohibits groundwater withdrawals during the time that a meter is removed or disabled, unless an AMD has been approved for that well. If not for these requirements, the Authority could not accurately monitor the amount of water withdrawn from the aquifer.

Section 711.414 requires non-exempt well owners to read their meters and file annual water use reports reflecting withdrawals during the previous year. The Authority relies on this reporting requirement to gather vital information about withdrawals made from a well on an annual and monthly basis. Such information is necessary to support the Authority's regulatory programs and to allow the Authority to monitor compliance with permit withdrawal amounts.

Section 711.416 provides that the Authority may enter land where a well is situated in order to inspect the meter, conduct maintenance or repairs, or perform tests. This authority is based on §36.123 of the Texas Water Code and provides a necessary tool to allow the Authority to implement its regulatory program and monitor and enforce compliance with the Act.

Section 711.418 prohibits a person from taking any action to disable or impair the accuracy of a meter. This section is meant to help preserve the integrity of meters on Edwards Aquifer wells and to prohibit persons from taking actions that would undermine the Authority's regulatory duties.

Section 711.420 specifies a variety of enforcement options that the Authority may pursue if withdrawals are not metered in accordance with Subchapter M. This list is not intended to be exhaustive or to preclude other means not specifically mentioned. It is meant to put users on notice of some of the enforcement options available to the Authority.

Section 2001.0225 of the Texas Government Code requires an agency to perform, under certain circumstances, a regulatory analysis of major environmental rules ("RIAMER"). There are two primary components that must be met before a RIAMER is required. First, no RIAMER need be prepared if the rules in question are not "major environmental rules" or "MERs." Second, even if the rules are MERs, no RIAMER need be prepared if adoption of the MERs would not result in any one of the following criteria listed in §2001.0225(a)(1)-(4):

1. the MER would "exceed" a standard set by federal law, unless the MER is specifically required by state law;

2. the MER would "exceed" an express requirement of state law, unless the MER is specifically required by federal law;

3. the MER would "exceed" a requirement of a delegation agreement or contract between the state and an agency or representative of the federal governmental to implement a state and federal program; or

4. the MER is adopted solely under the "general powers" of the agency instead of under a specific state law.

The Act requires the Authority to regulate the withdrawal of groundwater from the aquifer, including the rate and quantity of such withdrawals. The Act acknowledges that this cannot be effectively accomplished unless aquifer wells are metered or alternative methods are in place on each non-exempt well for measuring the rate and quantity of withdrawals, and the results are reported to the Authority. The Chapter 711 Subchapter M rules clarify the details of when and how meters or alternative measuring methods are to be installed on aquifer wells, who must pay for and maintain such devices, the design criteria for such devices, how such devices must be maintained, how groundwater use must be reported to the Authority, and so on. Such rules are normally integral parts of a water law-based regulatory program. The specific intent of Subchapter M is to support the Authority's aquifer management fee, enforcement and data collection program. Therefore, the Subchapter M rules are not MERs based on this rationale because they do not have the specific intent to "protect the environment" or "reduce risks to human health from environmental exposure."

Further, even if any of the Subchapter M rules were MERs, no RIAMER need be prepared for those rules because none meet any of the criteria listed in APA §2001.0225(a)(1)-(4). First, the Subchapter M rules do not exceed a standard set by federal law. The only reasonably related federal law establishes the Sole Source Aquifer Program implemented by the EPA for portions of the Edwards Aquifer. There is no federal law that specifically requires the rate and quantity of withdrawals of Edwards Aquifer groundwater to be metered. Therefore, the Subchapter M rules do not exceed a standard set by federal law. Moreover, even if the rules did exceed a standard set by federal law, the rules are specifically required by the Act, a state law which requires the Authority to, among other things: manage, conserve, preserve and protect the aquifer; adopt rules to carry out its powers and duties under the Act; regulate permits, manage withdrawals and points of withdrawals from the aquifer; require meters or alternative measuring methods on all non-exempt wells; and require the submission of water use reports. See Act §§1.08(a), 1.11(a), (b), (d)(2) and (h), 1.15(a), 1.31, 1.32, 1.33 and 1.36 of the Act). In addition, §36.111 of the Texas Water Code requires that records on the production of groundwater be kept and reported. Sections 36.123 and 49.221 of the Texas Water Code empower the Authority to, among other things, enter the land of a well owner to inspect, test, maintain or repair wells or meters located on the land.

Second, the Subchapter M rules do not exceed an express requirement of state law. Instead, the rules are designed to carry out the Authority's statutory responsibility to: manage, conserve, preserve and protect the aquifer, adopt rules to carry out its powers and duties under the Act, to regulate permits, manage withdrawals and points of withdrawals from the aquifer, to require meters or alternative measuring methods on all non-exempt wells, and to require the submission of water use reports. *See* Act §§1.08(a), 1.11(a), (b), (d)(2) and (h), 1.15(a), 1.31, 1.32, 1.33 and 1.36. In addition, §36.111 of the Texas Water Code requires that records on the production of groundwater be kept and reported. Sections 36.123 and 49.221 of the Texas Water Code empower the Authority to, among other things, enter the land of a well owner to inspect, test, maintain or repair wells or meters located on the land. The rules are designed to implement these express requirements of state law. Other than these provisions, there are no other "express requirements of state law" which could be exceeded by these rules.

Third, the Subchapter M rules do not exceed a requirement of a delegation agreement or contract between the State of Texas and an agency or representative of the federal government to implement a state and federal program. The subject matter of these rules is not covered by any delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program.

Fourth, the Subchapter M rules are not being adopted solely under the general powers of the Authority instead of under a specific state law. While these rules are adopted in part under the Authority's general powers, they are also adopted under the Act, a specific state law regarding the Edwards Aquifer. In particular, the rules are adopted pursuant to §§1.08(a), 1.11(a), (b), (d)(2) and (h), 1.15(a), 1.31, 1.32, 1.33 and 1.36 of the Act, §36.111 of the Texas Water Code and §§36.123 and 49.221 of the Texas Water Code.

For these reasons, it is not necessary to perform a RIAMER on the Chapter 711 Subchapter M rules.

Five public hearings were held on the Chapter 711 Subchapter M rules and other rules proposed by the Authority on: Monday, October 2, 2000 at 6:00 p.m. at the conference center of the Edwards Aquifer Authority, 1615 N. St. Mary's Street, San Antonio, Texas; Tuesday, October 3, 2000 at 6:00 p.m., at St. Paul's Lutheran Church, 1303 Avenue M, Hondo, Texas; Wednesday, October 4, 2000 at 6:00 p.m., at the San Marcos Activity Center, 501 E. Hopkins, San Marcos, Texas; Wednesday, October 11, 2000 at 6:00 p.m., at the Sgt. Willie DeLeon Civic Center, 300 E. Main Street, Uvalde, Texas; and Thursday, October 12, 2000, at 6:00 p.m., at the New Braunfels Civic Center, 380 S. Seguin Avenue, New Braunfels, Texas.

The public comment period closed on October 30, 2000. Oral and/or written comments were provided by San Antonio Water System ("SAWS"), James C. Harden, Jr. of Mortellaro's Nursery, Inc. ("Harden"), Andrew C.A. Donnelly on behalf of LBG-Guyton Associates ("LBG-Guyton"), Andrew J. Aelvoet on behalf of Southwest Texas Federal Land Bank ("Federal Land Bank"), Raymond Bartran ("Bartran"), Texas Farm Bureau ("TFB"), and Robert Grossenbacher ("Grossenbacher")

Chapter 711, Subchapter M, rules generally

Public Comment No. 1:

TFB maintains that a takings impact statement ("TIA") was required before the Authority provided public notice of the proposed rules.

Authority Response:

The Authority disagrees with the commenter. As explained in its notice of proposed rule in connection with this subchapter, the Authority has determined that it need not prepare a TIA in connection with the proposal of these rules. First, the Authority has made a "categorical determination" that rules establishing procedures and criteria for the installation of meters and the record-keeping and reporting requirements related thereto do not affect private real property. The proposed rules clarify the details of when and how meters or alternative measuring methods are to be installed on aquifer wells, who must pay for and maintain such devices, the design criteria for such devices, how such devices must be maintained, how groundwater use must be reported to the Authority, and so on. They have no direct affect on private real property and may not result in a taking. Second, the Authority's action in adopting these rules is an action that is reasonably taken to fulfill an obligation mandated by state law and is thus excluded from the Property Rights Act under §2007.003(b)(4) of the Texas Government Code. *See* §§1.08(a), 1.11(a), (b), (d)(2), and (h), 1.15(a) 1.31, 1.32, 1.33, and 1.36 of the Act, and §§36.111, 36.123, and 49.221 of the Texas Water Code. This conclusion is supported by the decision in *Edwards Aquifer Authority v. Bragg*, 21 S.W.3d 375 (Tex. App.-San Antonio, pet. denied) ("*EAA v. Bragg*"). Third, it is the position of the Authority that all valid actions of the Authority are excluded from the Property Rights Act under §2007.003(b)(11)(C) of the Texas Government Code as actions of a political subdivision taken under its statutory authority to prevent waste or protect the rights of owners of interest in groundwater. Accordingly, a TIA need not be performed in connection with the proposal of these rules.

Public Comment No. 2:

Grossenbacher believes it would be burdensome to require water reports, record keeping, and meter installation for small wells (those using less than 25,000 gallons of water per day) because the amount of the paperwork involved takes attention away from and has a detrimental effect on day-to-day business.

Authority Response:

The Authority agrees, in part, and disagrees, in part, with the commenter. Under the Authority rules, small wells which meet the criteria for exempt wells are not subject to the metering and reporting requirements set forth in subchapter M. Wells that do not meet such criteria (*e.g.*, wells used for irrigation, municipal or industrial purposes) are not exempt and must comply with the metering and reporting requirements stated in subchapter M even if the well produces less than 25,000 gallons of water per day. The Authority lacks the statutory authority to exempt all small wells from metering and reporting requirements.

Section 711.402(d)

Section 711.402 states the basic duty to install and operate a meter. Subsection (d) of that section, as proposed, states that "all meters shall be installed, operated, maintained, and repaired in accordance with the manufacturer's standards, instructions, or recommendations, and shall ensure an error of not greater than five percent."

Public Comment No. 3:

SAWS suggests that §711.402(d) be modified to clarify that each meter is required to maintain an accuracy of five percent. To that end, SAWS suggests that §711.402(d) read as follows: "*Each* meter shall . . . and *the owner* shall ensure an error of not greater than . . . ."

Authority Response:

The Authority agrees in part, and disagrees, in part, with the commenter. The Authority agrees that *each* meter is required to maintain the five percent accuracy and has modified the rule accordingly. However, the Authority declines to add the words, "the owner," to subsection (d). Subsections (a) and (c) of §711.402, and §711.404, already make it clear that it is the responsibility of the owner to install and operate a meter that meets all standards and requirements stated in these rules, including the five percent accuracy requirement.

Section 711.402(e)

Subsection (e) of §711.402, as proposed, provides that "all dual status wells shall be installed and constructed to locate the meter such that all withdrawals made under a permit are metered separately and not commingled with any exempt withdrawals."

Public Comment No. 4:

SAWS asserts that it should be optional whether to separately meter dual status wells and requests that subsection (e) of §711.402 be modified so that it reads as follows: "Dual status wells must be constructed to locate meters such that exempt and nonexempt withdrawals made under the permit are metered separately if the owner does not want to pay Aquifer Management Fees on exempt withdrawals."

Authority Response:

The Authority disagrees with the commenter. The Authority allows exempt withdrawals to be made from permitted wells in limited circumstances. In such instances, the Authority believes that it should have the means to confirm the amount of water withdrawn for permitted use and the amount withdrawn for exempt use.

Public Comment No. 5:

Bartran comments that subsection (e) of §711.402 recognizes dual status wells, and is thus not in conformity with §711.46 of the Authority's rules.

Authority Response:

The Authority agrees with the commenter. The Authority has determined that §711.402(e), as proposed, requires clarification and modification in light of §711.46 of the Authority's rules. Subsection (e) of §711.402 has been modified to achieve consistency with §711.46 as well as greater clarity.

Section 711.404(a)

Section 707.404(a), as proposed, states that "except as provided in subsection (b), all meters shall be designed, owned, installed, operated, maintained and repaired by the owner of the well, at the cost of the well owner."

Public Comment No. 6:

SAWS asserts that §711.404(a)'s provision requiring a well owner to design a meter may be onerous and accordingly suggests deleting the word "designed" from that subsection.

Authority Response:

The Authority agrees with the commenter and has therefore deleted the word "designed" from §707.404(a). The Authority has also decided to clarify §707.404(a) so that it will now read as follows: "Except as provided in subsection (b), the owner of a well shall be responsible for the installation, operation, maintenance, and repair of the meter associated with that well."

Section 711.404(c)

Subsection (c) of §711.404 covers the situation where the owner of a irrigation well (on which there is an Authority owned meter) "transfers all or part of the purpose of use of water to a use other than irrigation" In such an instance, this subsection requires the well owner to reimburse the Authority for a portion of the Authority's costs related to that meter.

Public Comment No. 7:

SAWS notes that under the Authority's rules, the owner of an irrigation well may not transfer all of its groundwater right, asserts the Authority must have a way to verify that the remainder of the right is not exceeded through pumping, and seeks the deletion of §711.404(c).

Authority Response:

The Authority disagrees with the commenter. First, the Authority notes that the owner of an irrigation well may not transfer all of the place or purpose of use of its groundwater withdrawal right. Under subsection (c) of §711.324 (relating to Prohibited Transfers), the place or purpose of use of all or part of the base irrigation groundwater component of an initial regular permit or interim authorization status is not transferable. However, the *ownership* of all of the groundwater withdrawal right is fully transferable. Second, §§711.340 and 711.342 of the Authority's rules allow for the conversion of base irrigation groundwater. Once converted, §§711.344 and 711.346 of the Authority's rules allow for the transfer of the purpose of use of such a groundwater withdrawal right. When §711.404(c) refers to the transfer of "*all* . . . of the purpose of use of water from the well to a use other than irrigation," it contemplates the transfer of the unrestricted portion of the groundwater withdrawal right and the transfer of that portion which was converted from base irrigation groundwater. With regard to the commenter's concern that the Authority must be able to verify that the remainder of the right not transferred is not exceeded through overpumping, the Authority will be able to monitor such matters through metering and the required filing of groundwater use reports.

Public Comment No. 8:

Federal Land Bank objects to §711.404(c) on the grounds that it exceeds the scope of the Authority's power under §1.31(b) of the Act which states that "the Authority is responsible for costs of purchasing, installing, and maintaining, measuring devices, if required, for an irrigation well in existence before September 1, 1993."

Authority Response:

The Authority disagrees with the commenter. The commenter appears to suggest that §1.31(b) of the Act requires the EAA to indefinitely assume all costs of a meter associated with a well, which, as of September 1, 1993, was a irrigation well, regardless of whether the purpose of use of the water from that well is ever changed. The Authority disagrees with such an interpretation of §1.31(b). The intent of §1.31(b) is to relieve an existing irrigation user from the cost of installing, operating, and maintaining a meter. If a well formerly used for irrigation becomes, in whole or in part, a well used for another purpose, this protection should no longer apply to the extent that the well is used for the other purpose.

Section 711.406

Section 711.406 states the requirement that no meter may be installed or modified without the approval of the general manager. Subsection (b) of that section sets forth the criteria to be used by the general manager in reviewing and approving an application to install or modify a meter.

Public Comment No. 9:

SAWS suggests that the general manager should be required to approve an application to modify a meter within thirty days and that §711.406(b) should be modified to indicate such a requirement.

Authority Response:

The Authority disagrees with the commenter. Although the Authority believes that such applications should and will be handled expeditiously (often within 30 days), the Authority declines to impose a thirty day deadline on the general manager in this situation.

However, upon examining the text of §711.406, as proposed, the Authority has concluded that the text of the Authority should be revised to improve clarity and consistency with §707.413 of the Authority's rules and to correct typographical errors.

Section 711.406(b)(4)

Subsection (b)(4) of §711.406, as proposed, states that the general manager shall approve an application to install or modify a meter if such an application shows, among other things, that the totalizing register of the meter "has the capacity to record the total quantity of groundwater withdrawn from the aquifer for not less than one full year . . . .."

Public Comment No. 10:

SAWS seeks clarification that the totalizing register will not turnover within a year of operation and suggests modified language for subsection (b)(4).

Authority Response:

The Authority agrees in part, and disagrees, in part, with the commenter. The Authority agrees that the intent of §707.406(b)(4) is to assure that the totalizing register of the meter will not turnover within a year of operation. The Authority has modified §707.406(b)(4) to clarify that intent, but in different manner than that suggested by SAWS.

Section 711.406(b)(7)

Subsection (b)(7) of §711.406 states the general manager shall approve an application for an alternative measuring method if the application shows, among other things, that "the interest of the Authority in ensuring accurate and uniform groundwater withdrawal data for compliance and aquifer management purposed is outweighed by the burden on the application to install and operate a meter."

Public Comment No. 11:

SAWS argues the text of §711.406(b)(7) should be rearranged to provide greater clarity. SAWS urges that this provision should read as follows: "for an alternative measuring method, if the burden on the applicant to install and operate a meter outweighs the interest of the Authority in ensuring accurate and uniform groundwater withdrawal data for compliance and aquifer management purposes."

Authority Response:

The Authority disagrees with the commenter. The Authority believes that SAWS suggested revisions to §711.406(b)(7) provide no greater clarity as compared with the text of that provision as proposed.

Section 711.406(c)

Subsection (c) of §711.406 provides that "within 5 days after installation or modification and prior to the commencement of operation of the meter, the owner of the meter shall give written notice to the Authority of the installation and the intended start date so the Authority may inspect and approve the meter installation or modification."

Public Comment No. 12:

SAWS believes that meter inspections should be at the option of the Authority and that wells should not be precluded from being operated while waiting for the Authority's inspection. Accordingly, SAWS urges that subsection (c) of §711.406 be modified to read as follows: "Within 5 days after installation or modification, the owner of the meter shall give written notice to the Authority of the installation and the intended start date so the Authority may inspect and approve the meter installation or modification."

Authority Response:

The Authority agrees with the commenter. The Authority believes that it is sufficient for the Authority to be given notice of a meter installation or modification and intended start date and so that the Authority may inspect and approve the installation or modification. While the Authority intends to inspect the meter installation or modification soon after receiving such notice, the Authority agrees that a well owner should not be prevented from using that meter until after such an inspection and approval. The Authority has therefore modified subsection (c) of §711.406 to clarify this intent.

Section 711.410

Section 711.410 governs the situation where an owner of a well has reason to believe that a condition exists that may affect the accuracy of a meter. It specifies that in such instances, a well owner has a duty to notify the general manager that the accuracy of the meter may be in question.

Public Comment No. 13:

Harden notes that when a meter is removed for repair, there is no procedure regarding who to notify, how to notify, or how to get approval of alternative methods to measure withdrawals. Harden suggests that the EAA establish a form and procedure in this area as opposed to just verbal notification.

Authority Response:

The Authority agrees, in part, and disagrees, in part, with the commenter. Section 711.410 provides a procedure by which a well owner shall provide notice to the Authority of any condition that may affect the accuracy of the meter. While it may be advisable for such notice to be submitted in writing, the Authority does not want to create additional burdens that may discourage persons from notifying the Authority of conditions that may affect the accuracy of the meter as expeditiously as possible. The Authority has modified subsection (a) of §711.410 to provide for, but not require, written notification.

Section 711.412

Section 711.412, as proposed, establishes requirements and sets forth procedures relating to the removal and disabling of meters.

Public Comment No. 14:

With respect to this section, Harden asserts that formal and consistent guidelines are needed to provide stability and insulation against shifts in policy and interpretation that accompany changes in Authority staff. As a result, Harden requests the deletion of §411.412, calling it discriminatory.

Authority Response:

The Authority agrees, in part, and disagrees, in part, with the commenter. The Authority agrees that formal guidelines are often appropriate to provide stability and certainty to those who are regulated by the Authority. However, the Authority believes that this interest is served by the inclusion rather than the deletion of §711.412. Moreover, the Authority does not understand how §711.412 is discriminatory. The Authority declines to delete §711.412. However, in conducting its review of §711.412, the Authority has determined that it overlaps somewhat with §711.406. Accordingly, the Authority has modified §711.412 to reduce or eliminate such overlap.

Section 711.412(a)

Subsection (a) of §711.412 states that a meter may not be removed or otherwise disabled unless the owner provides notice of intent remove or disable the meter and the notice has been approved in writing by the general manager.

Public Comment No. 15:

Although SAWS believes that owners should be required to notify the Authority of routine maintenance of meters, SAWS asserts that there should be no requirement that the general manager approve, in writing, such routine maintenance. SAWS suggests that §711.412(a) be modified accordingly.

Authority Response:

The Authority agrees with the commenter. The Authority has modified subsection (a) of §711.412 to indicate that although a well owner must notify the Authority whenever he or she intends to remove or disable a meter, including for routine maintenance, the prior approval of the general manager is not required in order for routine maintenance to be performed. In addition, the Authority has also modified subsection (a) of §711.412 to require that notice to the Authority of the removal or disabling of a meter be in writing on a form provided by the general manager. Other clarifying changes to subsection (a) of §711.412 have also been made.

Section 711.412(b)

Subsection (b) of §711.412 provides that a meter may be removed or disabled only by the owner of the meter, the Authority or their authorized representatives.

Public Comment No. 16:

SAWS asserts that the Authority should not be permitted to remove or disable a meter that it does not own and requests a change to §711.412(b) to reflect that position.

Authority Response:

The Authority agrees with the commenter. It was never the Authority's intent that subsection (b) of §711.412 provide it with the authority to remove and disable a meter not owned by the Authority. The Authority has accordingly modified subsection (b) to clarify this intent.

Section 711.414

Section 711.414 provides that a well owner shall read the meter by March 1st of each year and file the results in an annual water use report on a form prescribed by the Authority.

Public Comment No. 17:

LBG-Guyton expresses concern about a lack of accurate data relating to pumpage of Edwards groundwater and asserts that collecting data on an annual basis, as required by §711.414, is insufficient. LBG-Guyton suggests meter readings on a monthly or weekly basis and groundwater use reports on a monthly basis. Similarly, SAWS asserts that the Authority cannot effectively manage the aquifer using only annual usage reports and suggests that the Authority require monthly reports.

Authority Response:

The Authority agrees, in part, and disagrees, in part, with the commenters. The Authority agrees that information on monthly usage of the aquifer is necessary in order for the Authority to effectively plan and implement groundwater management strategies. Certain months of the year are more prone to both drought and to increased groundwater usage and withdrawals. Information on each users' withdrawals on a monthly basis would prove to be invaluable in the context of drought management. The Authority has therefore decided to require permittees and persons with interim authorization status to read their meter or meters on a monthly basis. However, the Authority sees no need, at this time, to require that users actually file groundwater use reports on a monthly basis. The Authority will therefore continue to require permittees and persons with interim authorization to file a annual groundwater use reports but to require in that information on that report be stated on both an annual and a month-by-month basis. The Authority has revised §707 .414, in part, to reflect the changes discussed above. The Authority has also modified the title of §707.414.

Public Comment No. 18:

SAWS urges the elimination of subsection (a) of §711.414, as proposed, on the grounds that: (1) it is redundant with subsection (b) of §711.414, as proposed; and (2) no meter exists where there is an approved alternative measuring method. SAWS further urges that subsection (b) of §707.414, as proposed, be converted to subsection (a) and that reporting dates are changed so they consistent with Chapter 709 of the Authority's rules.

Authority Response:

The Authority agrees, in part, and disagrees, in part, with the commenter. The Authority agrees that there is redundancy between subsections (a) and (b) of §711.414, as proposed, and has therefore eliminated any such redundancy by rewriting §717.414. Furthermore, the Authority agrees that as proposed, §711.414 contained some inconsistencies with §709.21(c) and (e) of the Authority's rules with respect to due dates for the mailing and submittal of annual groundwater use reports for irrigation wells. Accordingly, in rewriting §707.414, the Authority has provided separate due dates for the mailing and submittal of annual groundwater use reports for irrigation an non-irrigation wells in order to achieve consistency with §709.21 of the Authority's rules.

Section 711.416

Section 711.416 provides that the Authority may enter the land of the well owner for the purpose of inspecting the condition of the meter, conducting maintenance and repair activities, or performing tests.

Public Comment No. 19:

SAWS contends the Authority should not maintain or repair meters that the Authority does not actually own. Additionally, SAWS urges that all meter testing should not harm the meters. SAWS recommends that the first sentence of §711.416 be revised as follows, adding the italicized language:

"At any reasonable time, the Authority may enter the land of the owner on which a well is situated for the purpose of inspecting the condition of the meter, conducting maintenance and repair activities *if authorized*, or performing *nondestrutive* tests."

Authority Response:

The Authority agrees, in part, and disagrees, in part, with the commenter. The Authority has no intent on conducting maintenance or repairs on meters it does not own. The Authority has modified §711.416 to add the words "if authorized" in order to reflect and clarify this intent. Moreover, the Authority agrees that the testing of meters should not harm the meters but disagrees that a rule is needed to specify that only *nondestructive* tests are to be performed.

The new sections are adopted pursuant to the following statutory provisions contained within the Act.

Section 1.08(a) of the Act provides that the Authority "has all of the powers, rights, and privileges necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer." This section provides the Authority with broad and general powers to take actions as necessary to manage, conserve, preserve, and protect the aquifer and to increase the recharge of, and prevent the waste or pollution of water in, the aquifer.

Section 1.11(a) of the Act provides that the Board of Directors ("Board") of the Authority "shall adopt rules necessary to carry out the authority's powers and duties under (Article 1 of the Act), including rules governing procedures of the board and the authority." This section provides broad rulemaking authority to implement the various substantive and procedural programs set forth in the Act related to the Edwards Aquifer, including the permitting program.

Section 1.11(b) of the Act requires the Authority to "ensure compliance with permitting, metering, and reporting requirements and . . . regulate permits." This section, in conjunction with §1.11(a) and (h) of the Act, and §2001.004(1) of the APA, requires the Authority to adopt and enforce the Chapter 711 rules.

Section 1.11(d)(2) of the Act empowers the Authority to enter into contracts. Pursuant to this section, the Authority may enter into contracts with well owners concerning meters and reimbursement for same under Subchapter M of the Chapter 711 rules.

Section 1.11(h) of the Act provides, among other things, that the Authority is "subject to" the APA. This section essentially provides that the Authority is required to comply with the APA in connection with its rulemaking, even though the Authority is a political subdivision and not a state agency that would generally be subject to APA requirements.

Section 1.15(a) of the Act directs the Authority to manage withdrawals from the aquifer and manage all withdrawal points from the aquifer as provided by the Act. This section is implemented, in part, through the Chapter 711 Subchapter M rules.

Section 1.31 of the Act provides that nonexempt well owners must install and maintain meters or alternative measuring devices to measure the flow rate and cumulative amount of water withdrawn from each well. The section further provides that the

Authority must pay for such meters on irrigation wells in existence on the effective date of the Act. These concepts are implemented in the Chapter 711 rules, primarily in Subchapter M.

Section 1.32 of the Act requires permittees to submit annual water use reports to the Authority. This section is implemented in Subchapter M.

Section 1.33 of the Act provides the criteria for exempt wells -- i.e., wells that produce no more than 25,000 gallons of water per day for domestic and livestock use and that are not within or serving a subdivision requiring platting. The section explains that such wells are exempt from metering requirements. However, such wells must be registered with the Authority. These concepts are implemented, in part, by the Chapter 711 Subchapter M rules.

Section 1.36 of the Act empowers the Authority to enter orders enforcing the terms and conditions of permits, orders, or rules, and to draft rules suspending permits for failure to pay required fees or violations of permits, orders or rules. These concepts are implemented, in part, by the Chapter 711 Subchapter M rules.

Chapter 36 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 36.111 requires the Authority to require aquifer users to keep and maintain reports of drilling, equipping, and completing water wells and the production and uses of groundwater. The Chapter 711 Subchapter M rules help implement these requirements.

Section 36.123 of the Texas Water Code empowers representatives of the Authority to enter land and perform tests and other inspections. The Chapter 711 Subchapter M rules help implement this authority.

Chapter 49 of the Texas Water Code generally applies to groundwater districts such as the Authority. Section 49.221 empowers representatives of the Authority to enter land and perform tests and other inspections. The Chapter 711 Subchapter M rules help implement this authority.

§711.402. Duty to Install and Operate Meter; Meter Installation Deadlines.

(a) Except as provided in subsection (b) of this section, the owner of a well shall install and operate a meter to measure the flow rate and cumulative amount of groundwater withdrawn from the well.

(b) Pursuant to §711.406 of this title (relating to Meter Installation Approval; Waiver of Duty to Install and Operate a Meter; Approval of Alternative Measuring Method), the owner of a well may apply to the Authority to waive the duty to install a meter in favor of an alternative measuring method of determining the amount of groundwater withdrawn from the aquifer. If the Authority approves a waiver for the owner of a well with an approved alternative measuring method, then the term "meter" as used in this subchapter shall mean "alternative measuring method."

(c) A meter shall be installed by the owner of a well no later than six months after the effective date of these rules. This deadline does not apply to meters installed by the Authority pursuant to §711.404(b) of this title (relating to Ownership, Maintenance, and Cost of Meters).

(d) Each meter shall be installed, operated, maintained, and repaired in accordance with the manufacturer's standards, instructions, or recommendations, and shall ensure an error of not greater than + five percent.

(e) Permitted non-exempt irrigation wells from which exempt withdrawals are allowed under subsection (b) of §711.46 of this title (relating to Dual Status Wells Prohibited) shall be constructed so that both permitted and exempt withdrawals are metered separately and not commingled. In such instances, the well owner is responsible for installing, operating, and maintaining two meters that comply with the requirements of this subchapter: one to measure permitted withdrawals and the other to measure exempt withdrawals.

§711.404. Ownership; Maintenance; and Costs of Meters.

(a) Except as provided in subsection (b), the owner of a well shall be responsible for the installation, operation, maintenance, and repair of the meter associated with that well.

(b) For any irrigation well in existence on September 1, 1993 that is not capped and from which withdrawals were made during the historical period, or any replacement to such well, meters shall be designed, owned, installed, and maintained by the Authority at the cost of the Authority. Meters for such irrigation wells shall be operated by the well owner at the cost of the well owner.

(c) If an owner of a well on which a meter owned by the Authority is installed transfers all or part of the purpose of use of water from the well to a use other than irrigation, then the owner of the well shall:

(1) reimburse the Authority on a pro rata basis for all of its meter installation and purchase costs, and, if appropriate, the Authority may convey ownership of the meter to the well owner; or

(2) notify the Authority in writing to remove the meter pursuant to §711.412 of this title (relating to Removal, Modification, or Disabling of Meters), and install a replacement meter in accordance with this subchapter.

§711.406. Meter Installation Approval; Waiver of Duty to Install and Operate Meter; Approval of Alternative Measuring Method.

(a) Except as provided in subsection (d), no meter or alternative measuring method, may be installed or modified prior to written approval given by the general manager of an application filed on a form prescribed by the Authority pursuant to §707.413 of this title (relating to Applications for Permits to Install or Modify Meter).

(b) The general manager shall approve an application to install or modify meter or alternative measuring method, if the general manager finds the application shows the following:

(1) the meter or alternative measuring method, has a certified error of not greater than + five percent;

(2) for a meter it meets the American Water Works Association design and operation standards for design, materials, and accuracy;

(3) the meter or alternative measuring method has a non-resettable totalizer, or lock box with resettable digital readout;

(4) the totalizing register of the meter or alternative measuring method has the capacity to record the total quantity of groundwater withdrawn from the aquifer for at least one full year; and

(5) the meter or alternative measuring method if equal to or greater than a discharge diameter of 4.0 inches, has an instantaneous readout for both flow rate and total quantity measured;

(6) the meter, or alternative measuring method, if used for the distribution of potable water, shall be American National Standards Institute/National Sanitation Foundation (ANSI/NSF) Standard 61 certified; and

(7) for an alternative measuring method, if the interest of the Authority in ensuring accurate and uniform groundwater withdrawal data for compliance and aquifer management purposes

is outweighed by the burden on the applicant to install and operate a meter.

(c) Within 5 days after installation or modification the owner of the meter shall give written notice to the Authority of the installation or modification and the intended start date so the Authority may inspect and approve the meter installation or modification.

(d) Subsection (a) does not apply to meters installed by the Authority under §711.404(b) of this title (relating to Ownership, Maintenance and Costs).

§711.410. Notice of Condition Affecting Accuracy of Meter; Corrective Action.

(a) If at any time the owner of a well has reason to believe that a condition, of any kind whatsoever, may exist that affects the accuracy of a meter, then the owner of the well shall, within seven days of learning of the fact(s), notify the general manager that the accuracy of the meter may be in question. Such notification may be in writing, on a form provided by the general manager.

(b) The general manager may conduct an investigation and, if facts warrant, direct the owner of the meter, at the owner's cost, to evaluate and test the accuracy of the meter and take appropriate corrective action, including replacement, to restore the accuracy and proper working condition of the meter in conformance with the requirements of this subchapter.

§711.412. Removal and Disabling of Meters.

(a) A meter may not be removed or otherwise disabled including for routine maintenance, unless the owner gives the Authority notice, in writing, on a form provided by the general manager, of the intent to remove or disable the meter. Except in cases of routine maintenance, such notice must be approved in writing by the general manager before the meter is removed or disabled.

(b) A meter may be removed or otherwise disabled, only by the owner of the meter or its authorized representative.

(c) During a period that a meter is removed or otherwise disabled, groundwater may not be withdrawn from the well, unless the general manager has approved an alternative measuring method pursuant to §711.406 of this title (relating to Meter Installation Approval; Waiver of Duty to Install and Operate Meter; Approval of Alternative Measuring Method) and §707.515 of this title (relating to Actions on Application by the General Manager).

§711.414. Meter Reading; Groundwater Use Reporting.

(a) Every permittee, or person with interim authorization status, shall accurately read the meter on a monthly and on an annual basis and shall file the results with the Authority by way of a written Annual Groundwater Use Report on a form prescribed by the Authority. The annual groundwater use report form prescribed by the Authority shall provide spaces to report withdrawals for both the entire year and on a month-by-month basis. Every permittee, or person with interim authorization status, shall assure that the Annual Groundwater Use Report reflects the withdrawals made during the preceding calendar year and shall include information on the amount of withdrawals made on both an annual and on a month-by-month basis.

(b) For all wells other than irrigation wells, a completed Annual Groundwater Use Report must be returned to the general manager by no later than March 1st of each year. The Authority shall mail annual groundwater use report forms to the users of such wells during January of each year.

(c) For irrigation wells, a completed Annual Groundwater Use Report must be returned to the general manager by no later than January 31st of each year. The Authority shall mail annual groundwater use report forms to the users of such wells during December of each year.

(d) Annual groundwater use report forms shall be furnished to anyone on request. In completing the report, a permittee, or person with interim authorization status, shall fill in the blanks to the best of his knowledge and ability in accordance with the instructions that accompany each form.

(e) No groundwater use report is required to be filed by persons owning an exempt well, although the Authority encourages persons owning exempt wells to file such a report.

§711.416. Entry on Land.

At any reasonable time, the Authority may enter the land of the owner on which a well is situated for the purpose of inspecting the condition of the meter, conducting maintenance and repair activities if authorized, or performing tests. The Authority will make all reasonable efforts to coordinate the entry with the owner of the land on which the well is situated.

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

Filed with the Office of the Secretary of State on December 28, 2000.

TRD-200009051
Gregory M. Ellis
General Manager
Edwards Aquifer Authority
Effective date: January 17, 2001
Proposal publication date: September 29, 2000
For further information, please call: (210) 222-2204

♦ ♦ ♦

TEXAS DEPARTMENT OF INSURANCE

Notification Pursuant to the Insurance Code, Chapter 5, Subchapter L

As required by the Insurance Code, Article 5.96 and 5.97, the ***Texas Register*** publishes notice of proposed actions by the Texas Board of Insurance. Notice of action proposed under Article 5.96 must be published in the ***Texas Register*** not later than the 30th day before the board adopts the proposal. Notice of action proposed under Article 5.97 must be published in the ***Texas Register*** not later than the 10th day before the Board of Insurance adopts the proposal. The Administrative Procedure Act, the Government Code, Chapters 2001 and 2002, does not apply to board action under Articles 5.96 and 5.97.

The complete text of the proposal summarized here may be examined in the offices of the Texas Department of Insurance, 333 Guadalupe Street, Austin, Texas 78714-9104.)

This notification is made pursuant to the Insurance Code, Article 5.96, which exempts it from the requirements of the Administrative Procedure Act.

Texas Department of Insurance

Final Action

The Commissioner of Insurance, at a public hearing under Docket No. 2472 held at 1:30 p.m., December 11, 2000 in Room 100 of the William P. Hobby Jr. State Office Building, 333 Guadalupe Street in Austin, Texas, adopted amendments proposed by Staff to the Texas Automobile Rules and Rating Manual (the Manual), Rule 48, and to the Automobile Liability Experience Rating Plan (the Plan), relating to filing requirements and the furnishing of information for experience rating. Staff's petition (Ref. No. A-1000-27-I), was published in the November 10, 2000, issue of the *Texas Register* (25 TexReg 11295).

Pursuant to these amendments, insurers, rather than the Texas Department of Insurance (Department), will perform all routine experience rating functions, subject to information requests by the Department. Insurers will be required to maintain experience data for five years and to supply any requesting company, agent, or insured with experience rating information within 30 calendar days of the request. Staff had initially proposed a response time of 15 days, but in response to filed comments, and upon reconsideration, Staff concluded that 30 days would be a more reasonable time period to allow companies adequate time to comply with requests for experience rating data. It is also consistent with the 30 day provision in the Insurance Code, Article 21.59 which requires insurers to provide claim information to certain insureds. The amendments, which include various editorial changes, are as follows: Rule 48, Section B, third paragraph; Section B.2.(a) and (b) are amended; Section B.2.(c) (deleted); Section B.2.(d) (redesignated as "(c)"); Section B.2.(e) (redesignated as "(d)"); Section B.4. (deleted); Section B.5. (redesignated as "B.4."); Section B.6. (redesignated as "B.5." and is also amended). The change to Manual Rule 48.D. is merely editorial. The sections of the Plan to be amended are as follows: Section III "Note 3" (deleted); Section IV.7.; and Administrative Rules.

The Insurance Code, Article 5.77 (enacted in 1953) authorizes the promulgation of "premium rating plans designed to encourage the prevention of accidents, to recognize the peculiar hazards of individual risks for...motor vehicle and other lines of Casualty Insurance...." This article does not mandate filing of experience rating information with the Department, and it allows the Commissioner broad rulemaking discretion regarding rating plans. The Board of Insurance Commissioners exercised that discretion and adopted a plan for experience rating of commercial automobiles, effective September 1, 1953, as evidenced in its July 30, 1953 letter to the manager of the Texas Automobile Insurance Service Office (TAISO). At the time, the Insurance Code, Article 5.10 (enacted in 1951) gave the Board "full power and control over any administrative agencies and/or stamping office which may be organized or established by insurer [sic] with the Board's approval to carry into effect the provisions..." regarding automobile insurance. The Board's letter described the duties to be performed by TAISO regarding the Plan.

In later years, prior to March 18, 1992, the provisions of the Plan and Rule 48 of the Manual required TAISO to operate the Plan, subject to supervision by the State Board of Insurance. Board Order No. 59371, effective March 18, 1992, changed all references in the Plan and Manual Rule 48 from TAISO to "the Department or a qualified entity." TAISO performed as the qualified entity until December 31, 1992, but during that year the Board abandoned the idea of having a qualified entity operate experience rating as discussed below.

Board Order No. 59787, effective January 1, 1993 amended the Plan and Manual Rule 48 to remove all references to "a qualified entity." The Department lacked adequate resources to perform all the functions that had been performed by TAISO, and the above order required insurers to perform some of those functions, subject to oversight by the Department.

Currently, the Department maintains a file for each individual experience rated risk in Texas. Upon receipt, policies, endorsements, and ownership information are placed in the appropriate individual file. The Department receives the calculated modifiers from insurers and updates an experience rating database accordingly. The Department may request additional information from insurers. The Department releases modifier information when requested. Although the Department maintains this information, it is the insurers' responsibility to calculate the experience modifiers and provide other insurers the experience data upon request. Specifically, through the amendments, the Department will no longer maintain a file on each experience rated risk or provide modifiers or other experience rating information pertaining to a specific risk. The Insurance Council of Texas (ICT), an entity that arose from the merger of TAISO and the Texas Insurance Advisory Association, made verbal comments and submitted a written statement in this proceeding. ICT proposed that it be designated as the "qualified entity" to handle experience rating functions for all insurers in the manner that TAISO did during part of 1992. Although ICT indicated its proposal would result in more uniformity and greater compliance than Staff's proposal, no evidence was found to support that conclusion. It is also possible that ICT's proposal would cost insurers more than Staff's proposal, and that those costs would be passed on to consumers. It appears the action sought by ICT would be a step backward in the trend to ease regulatory burdens on insurers writing commercial risks.

The purpose of this order is to eliminate unnecessary filing requirements for insurers as well as to continue oversight and improve regulatory efficiency, while maintaining adequate protection for consumers. The elimination of filing requirements for insurers will eliminate the current duplication that results from the Department maintaining and providing the same information insurers are currently required to provide. As Staff suggested, the Department will not continue to perform routine experience rating functions, but the amendments will require insurers: (1) to perform those functions, and (2) to maintain and make records available to the Department. Each insurer will be required to respond to inquiries regarding its experience rated risks, upon request from another insurer, an agent, or an insured. The Department will take appropriate action to insure that insurers are complying with the Manual and the Plan as amended.

The amendments as adopted by the Commissioner of Insurance are shown in exhibits on file with the Chief Clerk under Ref. No. A-1000-27-I, which are incorporated by reference into Commissioner's Order No. 00-1383.

The Commissioner of Insurance has jurisdiction over this matter pursuant to the Insurance Code, Articles 5.10, 5.77, 5.78, 5.96, 5.98, and 5.101.

This notification is made pursuant to the Insurance Code, Article 5.96, which exempts it from the requirements of the Government Code, Chapter 2001 (Administrative Procedure Act).

Consistent with the Insurance Code, Article 5.96(h), the Department will notify all insurers writing automobile insurance of this adoption by letter summarizing the Commissioner's action.

IT IS THEREFORE THE ORDER of the Commissioner of Insurance that the Manual and the Plan are amended as described herein, and the amendments are adopted to become effective on the 15th day after publication of the notification of the Commissioner's action in the *Texas Register*.

TRD-200009053
Lynda Nesenholtz
General Counsel and Chief Clerk
Texas Department of Insurance
Filed: December 28, 2000

♦ ♦ ♦

REVIEW OF AGENCY RULES

This Section contains notices of state agency rules review as directed by Texas Government Code, §2001.039. Included here are (1) notices of *plan to review;* (2) notices of *intention to review*, which invite public comment to specified rules; and (3) notices of *readoption*, which summarize public comment to specified rules. The complete text of an agency's *plan to review* is available after it is filed with the Secretary of State on the Secretary of State's web site (http://www.sos.state.tx.us/texreg). The complete text of an agency's rule being reviewed and considered for *readoption* is available in the ***Texas Administrative Code*** on the web site (http://www.sos.state.tx.us/tac).

For questions about the content and subject matter of rules, please contact the state agency that is reviewing the rules. Questions about the web site and printed copies of these notices may be directed to the ***Texas Register*** office.

Proposed Rule Reviews

Texas State Board of Pharmacy

Title 22, Part 15

(Editor's note: Due to an error by the Texas Register, the following Proposed Rule Review filed by the Texas State Board of Pharmacy was omitted from the December 29, 2000, issue of the Texas Register.)

The Texas State Board of Pharmacy proposes the review of Chapter 291 (§291.23), concerning Pilot or Demonstration Research Projects for Innovative Applications in the Practice of Pharmacy, pursuant to the Appropriations Act, 76th Legislature, Section 9-10.13.

Comments on the proposal may be submitted to Steve Morse, R.Ph., Director of Professional Services, Texas State Board of Pharmacy, 333 Guadalupe Street, Austin, Texas 78701.

TRD-200100038
Gay Dodson, R.Ph.
Executive Director/Secretary
Texas State Board of Pharmacy
Filed: January 3, 2001

♦ ♦ ♦

(Editor's note: Due to an error by the Texas Register, the following Proposed Rule Review filed by the Texas State Board of Pharmacy was omitted from the December 29, 2000, issue of the Texas Register.)

The Texas State Board of Pharmacy proposes the review of Chapter 295 (§295.13), concerning Drug Therapy Management by a Pharmacist under Written Protocol of a Physician, pursuant to the Appropriations Act, 76th Legislature, Section 9-10.13.

Comments on the proposal may be submitted to Steve Morse, R.Ph., Director of Professional Services, Texas State Board of Pharmacy, 333 Guadalupe Street, Austin, Texas 78701.

TRD-200100039
Gay Dodson, R.Ph.
Executive Director/Secretary
Texas State Board of Pharmacy
Filed: January 3, 2001

♦ ♦ ♦

Tables & Graphics

Graphic material from the emergency, proposed, and adopted sections is published separately in this tables and graphics section. Graphic material is arranged in this section in the following order: Title Number, Part Number, Chapter Number and Section Number.

Graphic material is indicated in the text of the emergency, proposed, and adopted rules by the following tag: the word "Figure" followed by the TAC citation, rule number, and the appropriate subsection, paragraph, subparagraph, and so on.

Figure: 30 TAC §101.303(f)(8)(C)

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

Where:

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

i = each emission unit in the source cap

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

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

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

d = the number of days in the use period

and

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

Where:

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

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

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

d = the number of days in the use period

Figure: 30 TAC §101.353(a)

$$A = \left[B\right] - X\left[B - \left(\frac{LA_{HA} * EF_{final}}{2000}\right)\right]$$

Where:

(1) A = number of allowances rounded to tenths of tons

(2) B = the facility's baseline emission rate and is calculated as follows:

(A) For facilities in operation prior to January 1, 1997,

$$= \frac{(LA_{97} * EF_{97}) + (LA_{98} * EF_{98}) + (LA_{99} * EF_{99})}{3(2000)}$$

Where: LA_{97} = the facility's level of activity, as certified by the executive director for 1997

LA_{98} = the facility's level of activity, as certified by the executive director for 1998

LA_{99} = the facility's level of activity, as certified by the executive director for 1999

EF_{97} = the faculty's emission factor, in pounds per unit of activity, (not to exceed any applicable federal or state regulation, rule, or permit limit), as certified by the executive director, for 1997.

EF_{98} = the faculty's emission factor, in pounds per unit of activity, (not to exceed any applicable federal or state regulation, rule, or permit limit), as certified by the executive director, for 1997.

EF_{99} = the faculty's emission factor, in pounds per unit of activity, (not to exceed any applicable federal or state regulation, rule, or permit limit), as certified by the executive director, for 1997.

(B) For new and modified facilities not in operation prior to January 1, 1997 and either have submitted, under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification), an application which the executive director has determined to be administratively complete before January 2, 2001, or have qualified for a permit by rule under Chapter 106 of this title (relating to Permits by Rule) and have commenced construction before January 2, 2001 and that have been in operation less than two complete consecutive calender years;

$$B = \frac{LA_{Allowable} * EF_{Allowable}}{2000}$$

Where $LA_{Allowable}$ = The level of activity authorized by the executive director until such time two consecutive calendar years of actual level of activity data is available

$EF_{Allowable}$ = The emission factor authorized by the executive director until such time two consecutive calendar years of actual emission data is available

(C) For new and modified facilities not in operation prior to January 1, 1997 and either have submitted, under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification), an application which the executive director has determined to be administratively complete before January 2, 2001, or have qualified for a permit by rule under Chapter 106 of this title (relating to Permits by Rule) and have commenced construction before January 2, 2001; and that have been in operation for two complete consecutive calender years;

$$B = \frac{(LA_{Year-1} * EF_{Year-1}) + (LA_{Year-2} * EF_{Year-2})}{2(2000)}$$

Where: LA_{Year-1} = the facility's level of activity, as certified by the executive director, for its first complete calender year of operation

LA_{Year-2} = the facility's level of activity, as certified by the executive director, for its second complete calender year of operation

EF_{Year-1} = the faculty's emission factor, in pounds per unit of activity, (not to exceed any applicable federal or state regulation, rule, or permit limit), as certified by the executive director, for its first complete calender year of operation

EF_{Year-2} = the faculty's emission factor, in pounds per unit of activity, (not to exceed any applicable federal or state regulation, rule, or permit limit), as certified by the executive director, for its first complete calender year of operation

(3) X = reduction factor, where:

(A) For all boilers, auxiliary steam boilers and stationary gas turbines within an electric power generating system, as defined in §117.10 of this title (relating to Definitions), located in HGA

(i) for January 1, 2002 through March 31, 2003, X = 0.00
(ii) for April 1, 2003 through March 31, 2004, X = 0.47
(iii) for April 1, 2004 through March 31, 2007, X = 0.95
(iv) on or after April 1, 2007, X = 1.00

(B) For all other sources

(i) for January 1, 2002 through March 31, 2004, X = 0.00
(ii) for April 1, 2004 through March 31, 2005, X = 0.44
(iii) for April 1, 2005 through March 31, 2007, X = 0.89
(iv) on or after April 1, 2007, X = 1.00

(C) For calendar years which include two different reduction factors, the reduction factor shall be adjusted using the appropriate ratio to reflect the number of months covered by each reduction factor.

(4) LA_{HA} = historical average level of activity, where:

(A) for facilities in operation prior to January 1, 1997, the average level of activity, as certified by the executive director, for 1997, 1998 and 1999, or

(B) for new and modified facilities not in operation prior to January 1, 1997 and either have submitted, under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification), an application which the executive director has determined to be administratively complete before January 2, 2001, or have qualified for a permit by rule under Chapter 106 of this title (relating to Permits by Rule) and have commenced construction before January 2, 2001; LA is

(i) The level of activity authorized by the executive director until such time two consecutive calendar years of actual level of activity data is available; or

(ii) When two complete consecutive calender years of actual level of activity data is available, the level of activity becomes the average of the facility's actual level of activity over those two consecutive calendar years of actual level of activity data.

(5) EF_{final} = emission factor, as listed in §§117.106, 117.206, or 117.475 of this title.

(6) For facilities using alternative emission specifications as allowed in §117.106(c)(2), §117.206(c)(17), or §117.475(c)(3) of this title (relating to Control of Air Pollution from Nitrogen Compounds), the level of activity for any formula will be the lowest of the level of activity as calculated in variables (2)(A), (2)(B), or the level of activity limited by an enforceable limit or commitment necessary to qualify alternative emission specification in §117.106(c)(2) or §117.206(c)(17).

Figure: 30 TAC §101.354(a)

$$A = \frac{LA_{CP} * EF_{CP}}{2000}$$

Where:

A	=	Allowances to be subtracted from the compliance account in tenths of Tons
LA_{CP}	=	the level of activity during the control period
EF_{CP}	=	the emission factor for the control period in lb of nitrogen oxides (NO_x) per unit of activity

Figure: 30 TAC §101.373(d)(1)

If SA > BA, then

(BER * BA) - (SER * SA) = reduction generated

Else if SA < BA, then:

(BER * BA) - (SER * BA) = reduction generated

where:

BER = the lower of the baseline emission rate or the most stringent emission rate

BA = baseline activity

SER = emission reduction strategy emission rate

SA = emission reduction strategy activity

Figure: 30 TAC §101.373(f)(8)(A)

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

Where:

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

i	=	each emission unit in the source cap
N	=	the total number of emission units in the source cap
H_i	=	actual daily heat input, in MMBtu per day, as calculated according to §117.223(b)(1) of this title
DEC_i	=	DEC used for each unit, in tons per year (for ERCs or MERCs) or tons (for DERCs), generated in accordance with subsection (b) of this section. If DEC_i is from a unit not subject to the emission specifications of §117.105 or §117.205 of this title, this term becomes DEC_i/F, where F is the offset ratio for the ozone nonattainment area where the unit is located (e.g. 1.2 for Beaumont/Port Arthur and 1.3 for Houston/Galveston).
d	=	the number of days in the use period

and

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

Where:

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

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

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

Figure: 30 TAC §101.373(f)(8)(B)

(PLA * PER) - (ALA * AER) =discrete emission credits needed

where:

PLA = proposed level of activity

PER = proposed emission rate

ALA = actual level of activity

AER = actual emission rate

Figure 1: 30 TAC Chapter 114 - Preamble

Emission Standards In grams per kilowatt-hour (g/kW-hr) and grams per horsepower-hour (g/hp-hr)					
Engine Power	Tier	Model Year	Non-Methane Hydrocarbons plus NO_x	Carbon Monoxide	Particulate Matter
kW<8 (hp<11)	Tier 1	2000	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	Tier 2	2005	7.5 (5.6)	8.0 (6.0)	0.80 (0.60)
8kW<19 (11hp<25)	Tier 1	2000	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	Tier 2	2005	7.5 (5.6)	6.6 (4.9)	0.80 (0.60)
19kW<37 (25hp<50)	Tier 1	1999	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	Tier 2	2004	7.5 (5.6)	5.5 (4.1)	0.60 (0.45)
37kW<75 (50hp<100)	Tier 2	2004	7.5 (5.6)	5.0 (3.7)	0.40 (0.30)
	Tier 3	2008	4.7 (3.5)	5.0 (3.7)	
75kW<130 (100hp<175)	Tier 2	2003	6.6 (4.9)	5.0 (3.7)	0.30 (0.22)
	Tier 3	2007	4.0 (3.0)	5.0 (3.7)	
130kW<225 (175hp<300)	Tier 2	2003	6.6 (4.9)	3.5 (2.6)	0.20 (0.15)
	Tier 3	2006	4.0 (3.0)	3.5 (2.6)	
225kW<450 (300hp<600)	Tier 2	2001	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)
	Tier 3	2006	4.0 (3.0)	3.5 (2.6)	
450kW560 (600hp750)	Tier 2	2002	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)
	Tier 3	2006	4.0 (3.0)	3.5 (2.6)	
kW>560 (hp>750)	Tier 2	2006	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)

Figure 2: 30 TAC Chapter 114 - Preamble

Implementation Dates of Federal Non-road Emission Standards		
Engine Power	**Tier**	**Model Year**
50 hp< 100	**2**	**2004**
	3	**2008**
100 hp< 175	**2**	**2003**
	3	**2007**
175 hp< 300	**2**	**2003**
	3	**2006**
300 hp< 600	**2**	**2001**
	3	**2006**
600 hp 750	**2**	**2002**
	3	**2006**
hp > 750	**2**	**2006**

Figure 1: 30 TAC Chapter 117 - Preamble

POTENTIAL NO_X EMISSION REDUCTIONS BY POINT SOURCE CATEGORY FOR HOUSTON/GALVESTON NONATTAINMENT AREA COUNTIES

Category	1997 Emissions (tpd)	% of Total Point	Chapter 117 NO_x RACT Reductions (%; tpd)	Tier I Reductions Combustion Modifications	Tier II Reductions Flue Gas Cleanup	Tier III Reductions = Tier I + II	Tier III ESAD* Rates lb/MMBtu
Utility Boilers	196.44	29.4	9%; 21 tpd	50%; 97.6 tpd	87%; 172 tpd	93%; 184 tpd	0.010 - 0.060
Turbines (+Duct Burners)	155.65	23.3	17%; 30 tpd	60%; 93.5 tpd	89%; 138 tpd	91%; 141 tpd	0.015 - 0.150
Heaters and Furnaces	110.12	16.5	0%; 0 tpd	50%; 54.9 tpd	84%; 92 tpd	88%; 97 tpd	0.010 - 0.036
IC Engines	86.37	12.9	30%; 29 tpd	50%; 43.5 tpd	86%; 74 tpd	91%; 75 tpd	0.045 - 0.133[1]
Industrial Boilers	85.98	12.9	10%; 9 tpd	40%; 34.3 tpd	87%; 75 tpd	92%; 79 tpd	0.010 - 0.089
Other	32.99	4.9	0%; 0 tpd	2%; 0.7 tpd	58%; 19 tpd	60%; 19 tpd	various
Overall Point Source	667.56	100.0	12%; 91 tpd	48%; 324 tpd	84%; 569 tpd	89%; 595 tpd	--

*ESAD = Emission specifications for attainment demonstration

[1](0.17 - 0.50 g/hp-hr)

Figure 2: 30 TAC Chapter 117 - Preamble

SUBCATEGORIES - POINT SOURCE POTENTIAL NO_X EMISSION REDUCTIONS FOR HOUSTON/GALVESTON NONATTAINMENT AREA COUNTIES

Category	1997 Emissions (tpd)	% of Total Point	Number of Units	Tier I Reductions Combustion Modifications	Tier II Reductions Flue Gas Cleanup	Tier III Reductions = Tier I + II	Tier III ESAD Rates
Utility Boilers							
Gas Wall-fired	78.11		16	50%; 39.06 tpd	90%; 70.30 tpd	95%; 74.33 tpd	0.010 lb/MMBtu
Gas Tangential-fired	13.34		5	30%; 4.00 tpd	90%; 12.01 tpd	93%; 12.46 tpd	0.010 lb/MMBtu
Coal Wall-fired	56.92		2	45%; 25.61 tpd	85%; 48.38 tpd	92%; 52.39 tpd	0.030 lb/MMBtu
Coal Tangential-fired	47.78		2	60%; 28.67 tpd	85%; 40.61 tpd	92%; 44.08 tpd	0.030 lb/MMBtu
Auxiliary Boilers	0.29		7	88%; 0.26 tpd	0%; 0 tpd	88%; 0.26 tpd	0.060 lb/MMBtu
Total Utility Boilers	196.44	29.4	32	50%; 97.6 tpd	87%; 172 tpd	93%; 184 tpd	
Turbines and Duct Burners							
Electric Generation	138.58		78	62%; 86.22 tpd	90%; 125.15 tpd	92%;127.78 tpd	0.015 lb/MMBtu
Compressors >10MW	4.90		16	61%; 2.99 tpd	90%; 4.41 tpd	93%; 4.58 tpd	0.015 lb/MMBtu
Compressors 1-10MW	6.44		22	60%; 3.86 tpd	90%; 5.80 tpd	90%; 5.80 tpd	0.015 lb/MMBtu
Compressors <1MW	0.42		40	0%; 0 tpd	70%; 0.29 tpd	70%; 0.29 tpd	0.150 lb/MMBtu
Elec. Peaking/Int.	3.16		29	14%; 0.44 tpd	76%; 2.40 tpd	78%; 2.47 tpd	0.015 lb/MMBtu
Test Cell	0.52		4	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Chemical Processing	0.30		2	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Emergency	0.02		2	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Total Turbines/DBs	155.65	23.3	193	60%; 93.51 tpd	89%; 138.05 tpd	91%; 141 tpd	
Process Heaters/Furnaces							
Gas-fired ≥100 MMBtuh	88.16		424	49%; 43.20 tpd	90%; 79.35 tpd	90%; 79.35 tpd	0.010 lb/MMBtu
Gas-fired ≥40<100MMBtuh	14.93		216	49%; 7.32 tpd	86%; 12.84 tpd	86%; 12.84 tpd	0.015 lb/MMBtu
Gas-fired <40 MMBtuh	6.98		726	62%; 4.33 tpd	0%; 0 tpd	62%; 4.33 tpd	0.036 lb/MMBtu
Oil-fired	0.05		1	33%; 0.02 tpd	85%; 0.04 tpd	90%; 0.04 tpd	2 lb/M gal
Total Process Heaters	110.12	16.5	1367	50%; 54.87 tpd	84%; 92.23 tpd	88%; 96.56 tpd	

Category	1997 Emissions (tpd)	% of Total Point	Number of Units	Tier I Reductions Combustion Modifications	Tier II Reductions Flue Gas Cleanup	Tier III Reductions = Tier I + II	Tier III ESAD Rates
IC Engines							
Lean-burn Gas	62.15		302	70%; 43.51 tpd	90%; 55.94 tpd	93%; 57.69 tpd	0.50 g/hp-hr
Rich-burn Gas	18.56		158	0%; 0 tpd	97%; 17.94 tpd	97%; 17.94 tpd	0.17 g/hp-hr
Emergency Diesel	5.4		196	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Other Diesel	0.20		10	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Test Cell	0.08		16	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Dual-fuel	0.02		1	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	5.83 g/hp-hr
Emergency Gas	0.02		15	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	--
Total IC Engines	86.37	12.9	699	50%; 43.51 tpd	86%; 73.88 tpd	88%; 75.63 tpd	
Industrial Boilers							
Gas-fired ≥100 MMBtuh	55.46		180	60%; 33.28 tpd	90%; 49.91 tpd	96%; 53.24 tpd	0.010 lb/MMBtu
RCRA BIF ≥100 MMBtuh	11.24		21	0%; 0 tpd	82%; 9.22 tpd	82%; 9.22 tpd	0.015 lb/MMBtu
RCRA BIF <100 MMBtuh	1.04		20	0%; 0 tpd	54%; 0.56 tpd	54%; 0.56 tpd	0.030 lb/MMBtu
Petroleum Coke-fired	11.60		1	0%; 0 tpd	90%; 10.44 tpd	90%; 10.44 tpd	0.057 lb/MMBtu
Gas ≥40 <100 MMBtuh	3.48		90	0%; 0 tpd	87%; 3.03 tpd	87%; 3.03 tpd	0.015 lb/MMBtu
Gas-fired <40 MMBtuh	1.60		235	62%; 0.99 tpd	0%; 0 tpd	62%; 0.99 tpd	0.036 lb/MMBtu
Wood-fired	1.01		3	0%; 0 tpd	78%; 0.79 tpd	78%; 0.79 tpd	0.046 lb/MMBtu
Rice Hull-fired	0.51		1	0%; 0 tpd	90%; 0.46 tpd	90%; 0.46 tpd	0.089 lb/MMBtu
Oil-fired	0.14		3	0%; 0 tpd	90%; 0.13 tpd	90%; 0.13 tpd	2 lb/M gal
Total Industrial Boilers	85.98	12.9	554	40%; 34.31 tpd	87%; 74.54 tpd	92%; 78.86 tpd	

Category	1997 Emissions (tpd)	% of Total Point	Number of Units	Tier I Reductions Combustion Modifications	Tier II Reductions Flue Gas Cleanup	Tier III Reductions = Tier I + II	Tier III ESAD Rates
Other							
Refinery Cat Crackers	14.93		13	0%; 0 tpd	90%; 13.44 tpd	90%; 13.44 tpd	13 ppmv @0%O_2
Incinerators ≥40 MMBtuh	4.02		23	0%; 0 tpd	80%; 3.22 tpd	80%; 3.22 tpd	0.030 lb/MMBtu
Incinerators <40 MMBtuh	1.93		247	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Flares	5.37		555	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Dryers - $MgCl_2$	1.05		1	0%; 0 tpd	90%; 0.95 tpd	90%; 0.95 tpd	10% of '97 rate
Dryers - Others	1.26		119	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Pulping Recovery Furnaces	1.71		3	0%; 0 tpd	64%; 1.09 tpd	64%; 1.09 tpd	0.05 lb/MMBtu
Steel Furnace ≥20 Ht Treat	0.17		4	35%; 0.06 tpd	0%; 0 tpd	35%; 0.06 tpd	0.09 lb/MMBtu
Steel Furnace ≥20 Reheat	0.66		5	50%; 0.33 tpd	0%; 0 tpd	50%; 0.33 tpd	0.06 lb/MMBtu
Steel Furnace <20MMBtuh	0.16		78	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Kilns - Lime	0.28		2	64%; 0.17 tpd	0%; 0 tpd	64%; 0.17 tpd	0.66 lb/ton CaO
Kilns - Lightweight Agg.	0.42		3	30%; 0.13 tpd	0%; 0 tpd	30%; 0.13 tpd	0.76 lb/ton LWA
Kilns - Other	0.08		14	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Nitric Acid	0.41		3	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Ovens	0.23		60	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Vents	0.18		49	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Miscellaneous	0.12		150	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Fugitives	0.01		6	0%; 0 tpd	0%; 0 tpd	0%; 0 tpd	–
Total Other	32.99	4.9	1334	2%; 0.69 tpd	57%; 18.70 tpd	59%; 19.39 tpd	

Figure: 30 TAC §117.108(c)(1)

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

Where:

i = each EGF in the electric power generating system

N = the total number of EGFs in the emission cap

H_i = (A) For the Beaumont/Port Arthur and Dallas/Fort Worth ozone nonattainment areas, the average of the daily heat input for each EGF in the emission cap, in million Btu per day, as certified to the executive director, for the system highest 30-day period in the nine months of July, August, and September 1996, 1997, and 1998. For EGFs exempt from the 40 Code of Federal Regulations (CFR) Part 75 monitoring requirements, if the heat input data corresponding to the system highest 30-day period (as determined for EGFs in the system subject to 40 CFR Part 75 monitoring) is not available, the daily average of the highest calendar month heat input in 1996-1998 may be used.

(B) For the Houston/Galveston ozone nonattainment area:

(i) The average of the daily heat input for each EGF in the emission cap, in million Btu per day, as certified to the executive director, for the system highest 30-day period in the nine months of July, August, and September 1997, 1998, and 1999;

(ii) For EGFs exempt from the 40 CFR Part 75 monitoring requirements, if the heat input data corresponding to the system highest 30-day period (as determined for EGFs in the system subject to 40 CFR Part 75 monitoring) is not available, the daily average of the highest calendar month heat input in 1997-1999 may be used; and

(iii) The level of activity authorized by the executive director for the third quarter (July, August, and September), until such time two consecutive third quarters of actual level of activity data are available, shall be used for the following:

(I) EGFs for which the owner or operator has submitted, under Chapter 116 of this title, an application determined to be administratively complete by the executive director;

(II) EGFs which qualify for a permit by rule under Chapter 106 of this title; and

(III) EGFs which were not in operation prior to January 1, 1997.

R_I = (A) For EGFs in the Beaumont/Port Arthur ozone nonattainment area, the emission limit of §117.106(a) of this title;

(B) For EGFs in the Dallas/Fort Worth ozone nonattainment area, the emission limit of §117.106(b) of this title; and

(C) For EGFs in the Houston/Galveston ozone nonattainment area, the emission limit of §117.106(c) of this title.

Figure: 30 TAC §117.205(b)(6)

$$EL_2 = \frac{(EL_1)(1.25)(T_1) + (EL_1)(T_2)}{(T_1 + T_2)}$$

EL_2	=	Time-weighted emission limitation for each 30-day period, in lb $NO_{x/}$MMBtu of heat input.
EL_1	=	Appropriate emission limitation for gas-fired boiler from §117.205(b)(1)(A) - (F) of this title or gas-fired process heaters from §117.205(b)(2)(A) - (B) of this section, in lb NO_x/MMBtu of heat input.
1.25	=	Factor used as a multiplier times the appropriate emission limitation when firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period.
T_1	=	Time in hours when firing gaseous fuel which contains more than 50% hydrogen by volume, over an eight-hour period during each 30-day period. The time period when hydrogen rich fuel is combusted must, at a minimum, be a consecutive eight-hour period to be used in the determination of T_1.
T_2	=	Time in hours when firing gaseous fuel or hydrogen rich fuel (for less than eight consecutive hours) during each 30-day period;

Figure: 30 TAC §117.210(c)(1)

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

Where:

i = each EGF in the electric power generating system

N = the total number of EGFs in the emission cap

H_i = (A) The average of the daily heat input for each EGF in the emission cap, in million Btu per day, as certified to the executive director, for the system highest 30-day period in the nine months of July, August, and September 1997, 1998, and 1999;

(B) For EGFs exempt from the 40 Code of Federal Regulations (CFR) Part 75 monitoring requirements, if the heat input data corresponding to the system highest 30-day period (as determined for EGFs in the system subject to 40 CFR Part 75 monitoring) is not available, the daily average of the highest calendar month heat input in 1997-1999 may be used; and

(C) The level of activity authorized by the executive director for the third quarter (July, August, and September), until such time two consecutive third quarters of actual level of activity data are available, shall be used for the following:

(i) EGFs for which the owner or operator has submitted, under Chapter 116 of this title, an application determined to be administratively complete by the executive director;

(ii) EGFs which qualify for a permit by rule under Chapter 106 of this title; and

(iii) EGFs which were not in operation prior to January 1, 1997.

R_i = (A) gas-fired boilers, 0.010 pound NO_x per million British thermal units (lb NO_x per MMBtu) heat input;

(B) coal-fired or oil-fired boilers:

(i) wall-fired, 0.030 lb NO_x per MMBtu heat input; and

(ii) tangential-fired, 0.030 lb NO_x per MMBtu heat input;

(C) coke-fired boilers, 0.057 lb NO_x per MMBtu heat input;

(D) stationary gas turbines:

(i) rated at 1.0 megawatt (MW) or greater, 0.015 lb NO_x per MMBtu heat input; and

(ii) rated at less than 1.0 MW:

(I) with initial start of operation on or before December 31, 2000, 0.15 lb NO_x per MMBtu heat input; and

(II) with initial start of operation after December 31, 2000, 0.015 lb NO_x per MMBtu heat input;

(E) duct burners used in turbine exhaust ducts, 0.015 lb NO_x per MMBtu heat input;

(F) stationary, reciprocating, dual-fuel internal combustion engines:

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

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

(G) as an alternative to the emission specifications in subparagraphs (A) - (F) of this paragraph for units with an annual capacity factor of 0.0383 or less, 0.060 lb NO_x per MMBtu heat input.

Figure: 30 TAC §117.210(c)(2)

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

Where:

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

H_{mi} = The maximum heat input, as certified to the executive director, allowed or possible (whichever is lower) in a day.

IN ADDITION

The ***Texas Register*** is required by statute to publish certain documents, including applications to purchase control of state banks, notices of rate ceilings, changes in interest rate and applications to install remote service units, and consultant proposal requests and awards.

To aid agencies in communicating information quickly and effectively, other information of general interest to the public is published as space allows.

Office of Consumer Credit Commissioner

Notice of Rate Ceilings

The Consumer Credit Commissioner of Texas has ascertained the following rate ceilings by use of the formulas and methods described in Sections 303.003, 303.005, and 303.009, Tex. Fin. Code.

The weekly ceiling as prescribed by Sec. 303.003 and Sec. 303.009 for the period of 01/01/01 - 01/07/01 is 18% for Consumer [1]/Agricultural/Commercial [2]/credit thru $250,000.

The weekly ceiling as prescribed by Sec. 303.003 and Sec. 303.009 for the period of 01/01/01 - 01/07/01 is 18% for Commercial over $250,000.

The monthly ceiling as prescribed by Sec. 303.005[3] for the period of 01/01/01 - 01/31/01 is 18% for Consumer/Agricultural/Commercial/credit thru $250,000.

The monthly ceiling as prescribed by Sec. 303.005 for the period of 01/01/01 - 01/31/01 is 18% for Commercial over $250,000.

[1]Credit for personal, family or household use.

[2]Credit for business, commercial, investment or other similar purpose.

[3]For variable rate commercial transactions only.

TRD-200009039
Leslie L. Pettijohn
Commissioner
Office of Consumer Credit Commissioner
Filed: December 27, 2000

♦ ♦ ♦

Notice of Rate Ceilings

The Consumer Credit Commissioner of Texas has ascertained the following rate ceilings by use of the formulas and methods described in Sections 303.003 and 303.009, Tex. Fin. Code.

The weekly ceiling as prescribed by Sections 303.003 and 303.009 for the period of 01/08/01 - 01/14/01 is 18% for Consumer[1]/Agricultural/Commercial[2]/credit thru $250,000.

The weekly ceiling as prescribed by Sections 303.003 and 303.09 for the period of 01/08/01 - 01/14/01 is 18% for Commercial over $250,000.

[1]Credit for personal, family or household use.

[2]Credit for business, commercial, investment or other similar purpose.

TRD-200100033
Leslie L. Pettijohn
Commissioner
Office of Consumer Credit Commissioner
Filed: January 3, 2001

♦ ♦ ♦

Texas Department of Criminal Justice

Notice of Award

The Texas Department of Criminal Justice hereby gives notice of a Contract Award for the Plane State Jail Multi-Purpose Building, Requisition Number: 696-FD-1-B005.

The Contract was awarded to DT Construction, Inc., as a full award for a dollar amount of $654,700.

TRD-200009070
Carl Reynolds
General Counsel
Texas Department of Criminal Justice
Filed: December 29, 2000

♦ ♦ ♦

Texas Council for Developmental Disabilities

Request for Proposals

The Texas Council for Developmental Disabilities announces the availability of funds for six separate grant projects. The Texas Council for Developmental Disabilities is established by and funded under state and federal law and is responsible for promoting the development of supports and services necessary for individuals with developmental disabilities to be fully included in their communities. The Council has a commitment to support projects that will be carried out by organizations that share the Council's vision and values.

Proposed projects are:

1) Partners in Policymaking - funding for one project, up to $385,000 per year for three years.

Background:

Partners in Policymaking, a nationally recognized leadership training program for people with disabilities and/or their families, has been funded by TCDD for over 10 years. The program provides at least 128 hours of structured training in best practices, current issues and trends in providing services and supports to people with severe disabilities, and development of advocacy-related skills, and follows the national model closely. The program is administered over eight weekends, each of which involves at least one overnight stay.

2) School to Work Transition projects - funding for three projects, up to $75,000 per year for three years.

Background:

Up to three projects will be funded to demonstrate innovative and effective ways of providing supports and assistance to students with disabilities as they transition out of high school into the workplace.

3) Local Advocacy Support Networks - funding up to $25,000 per site, per year for three years. Maximum of five sites.

Background:

The Council has supported various advocacy and policy development efforts over the past decade. The Council has previously funded three local advocacy network projects in Houston and Austin. These projects have developed training and resource manuals and other publications, a listserv, public service announcements, a newsletter task force and have formed many alliances with groups, cross-disability networks, professionals, and individuals involved with disability issues. Funds are available to establish up to five additional cross-disability local advocacy networks in communities in Texas where no such organization currently exists.

4) Youth Leadership Training - funding for one project, up to $50,000 for year one and up to $100,000 per year for years two and three.

Background:

The project will coordinate planning and development of youth leadership forums to be conducted during years two and three. The forums will provide youths with disabilities the opportunity to come together to gain information, develop specific skills, and establish personal goals and plans in an experientially based program. The program, supported by adults who provide positive role models, will acknowledge and encourage the active involvement of youth in their communities, both today and in the future.

5) Transition to Higher Education Video - funding for one project, up to $75,000 for 12 to 18 months.

Background:

Funding will be provided to produce a video presenting the stories of students with disabilities who are currently enrolled in colleges or universities in Texas. Many students with disabilities do not receive the encouragement and support necessary to seek and achieve success at the post secondary level. Funding is available for the creation of a 6-8 minute video, produced in Spanish and English to be made available to students, their families, and educators to consider higher education as a viable option for students with disabilities.

6) New Initiatives - funding range, $20,000 to $50,000 per project. Total amount not to exceed $150,000. Projects are not to exceed three years in duration. Maximum of five projects.

Background:

The purpose of this Open Request for Proposals (RFPs) is to provide an opportunity for entities to submit proposal ideas for consideration. Proposals must be based on the goals and objectives addressed in the TCDD State Plan.

Grant/Application Terms

Continuation Funding: Projects may be eligible for continuation funding as specified in their original Request for Proposals. Continuation funding for each year will not be automatic. Consideration for continuation funding will include a review of the project's accomplishments, progress towards stated goals and objectives, financial management of funds, compliance with reporting requirements, the most recent program audit, results of TCDD's onsite reviews, and development of alternative funding.

Application Packet: For the full request for proposals, application forms and instructions, please submit a written, fax or e-mail request to: Carl Risinger, Grants Management Director, Texas Council for Developmental Disabilities, 4900 North Lamar Boulevard, Austin, Texas, 78751-2399, (512) 424-4084 (voice) or (512) 424-4097 (fax), E-mail TXDDC@txddc.state.tx.us. This information also may be obtained through TCDD's Website at http://www.txddc.state.tx.us. The completed application packet must be mailed or hand delivered. Application packets cannot be faxed.

Deadline: All Proposals will be accepted by mail or in person at the Texas Council for Developmental Disabilities, 4900 North Lamar Boulevard, Office #4435, 4th Floor, Austin, Texas, by March 12, 2001.

A nonfederal match of 25% is required of all projects. The nonfederal match may consist of "in-kind" value and/or nonfederal cash contributions. Project activities located in counties designated, as federal poverty areas require a minimum of 10% matching resources. An increasing match in subsequent years is requested and will be negotiated with TCDD.

TRD-200100031
Charles Schiesser
Chief of Staff
Texas Council for Developmental Disabilities
Filed: January 2, 2001

♦ ♦ ♦

East Texas Council of Governments

Request for Proposals

The East Texas Area Agency on Aging will accept proposals to provide services to persons in Camp, Gregg, Harrison, Marion, Panola, Rusk, and Upshur counties beginning April 1, 2001 and ending on September 30, 2003. Proposals to deliver nutrition services in Gregg, Harrison, Panola, and Upshur Counties must include congregate meals, home-delivered meals, and participant assessments as prescribed by the Older Americans Act, as amended. Transportation proposals will be accepted for the provision of Title III.B and Section 5311 Rural Public Transportation service to the general public in the seven counties listed above, 5307 Small Urban Transit Program for the elderly and disabled inside the city of Longview, and Title XIX Medical Transportation services in Harrison and Panola Counties. Transportation proposals must include services as prescribed by the Older Americans Act as amended, the Texas Department of Transportation, and the Federal Transportation Administration. Rural transportation proposals that do not include entire counties will not be accepted. Proposals should address FY-2001, 2002, and 2003 service levels. The initial contract will be for six months, with the option to renew for fiscal years 2002 and

2003. Proposals may be submitted by local governments, public or private non-profit organizations, or for-profit organizations. Unit rate contracts will be awarded for services other than Rural Public Transportation. Estimated available State and Federal funds for the last six months of FY-2001 are: $60,265 for congregate meals; $104,896 for home-delivered meals, including participant assessments; $105,630 for Title III.B, Elderly Transportation Services; $108,641 for Section 5311, Public Rural Transportation Services; $83,596 for Section 5307, Small Urban Transit Services for the Elderly and Disabled Inside the City of Longview; and, $45,000 (approximate) for Title XIX Medical Transportation Services.

Proposals must include a 10% local match, which may be cash, in-kind, or a combination of the two. Technical assistance for proposers will be offered in a one-time only bidders conference at the East Texas Council of Governments office, 3800 Stone Road, Kilgore, Texas, from 10:00 a.m. until 12:00 p.m. on January 19, 2001. APPLICATIONS MUST BE RECEIVED NO LATER THAN 5:00 P.M. ON February 9, 2001. Faxed proposals will not be accepted. All proposal requests must be obtained from and returned to: East Texas Council of Governments, Area Agency on Aging, 3800 Stone Road, Kilgore, Texas 75662, Attention: Claude I. Andrews

For additional proposal information, call (903) 984-8641.

TRD-200100034
Lynn Knight
Executive Director
East Texas Council of Governments
Filed: January 3, 2001

♦ ♦ ♦

Texas Department of Health

Licensing Actions for Radioactive Materials

The Texas Department of Health has taken actions regarding Licenses for the possession and use of radioactive materials as listed in the tables. The subheading "Location" indicates the city in which the radioactive material may be possessed and/or used. The location listing "Throughout Texas" indicates that the radioactive material may be used on a temporary basis at job sites throughout the state.

NEW LICENSES ISSUED:

Location	Name	License #	City	Amendment #	Date of Action
Port Arthur	Gulf Coast Cardiology Group PA	L05393	Port Arthur	00	12/04/00
Throughout Tx	C D S Enterprises Inc	L05356	College Station	00	12/14/00
Throughout Tx	Onion Valley Enterprises Inc	L05398	De Leon	00	11/30/00
Throughout Tx	Henley Enterprises	L05372	Hewitt	00	12/14/00

AMENDMENTS TO EXISTING LICENSES ISSUED:

Location	Name	License #	City	Amendment #	Date of Action
Abilene	NC-SCHI Inc	L02434	Abilene	63	11/29/00
Abilene	Hendrick Medical Center	L02433	Abilene	66	12/12/00
Arlington	Arlington Memorial Hospital Foundation Inc	L02217	Arlington	63	11/29/00
Arlington	Columbia Medical Ctr of Arlington Subsidiary LP	L02228	Arlington	51	12/13/00
Austin	Ambion Inc	L04307	Austin	10	11/30/00
Austin	Columbia St Davids Healthcare System LP	L03273	Austin	38	12/08/00
Austin	Austin Radiological Association	L00545	Austin	89	12/11/00
Baytown	Chevronphillips Chemical Company LP	L00962	Baytown	31	11/30/00
Baytown	Baytown Cardiology Associates	L05040	Baytown	02	12/08/00
Baytown	Jacinto MRI and Diagnostic Center	L04808	Baytown	08	12/12/00
Baytown	San Jacinto Methodist Hospital	L02388	Baytown	37	12/12/00
Beaumont	R Leldon Sweet MD PA	L05029	Beaumont	07	12/13/00
Beeville	Christus Spohn Health System Corporation	L04510	Beeville	11	12/11/00
Carrollton	Stmicroelectronics Inc	L03930	Carrollton	14	12/05/00
College Station	Prodigene Inc	L05252	College Station	01	11/30/00
College Station	Texas A & M University	L00448	College Station	105	12/15/00
Conroe	Sadler Clinic	L04899	Conroe	13	11/29/00
Corpus Christi	Driscoll Childrens Hospital	L04606	Corpus Christi	20	12/11/00
Corpus Christi	Spohn Hospital	L02495	Corpus Christi	64	12/02/00
Dallas	PET NET Pharmaceutical Services Inc	L05193	Dallas	06	12/05/00
Dallas	Heartplace	L04607	Dallas	26	12/04/00
Dallas	Mallinckrodt Inc	L03580	Dallas	40	12/06/00
Dallas	Texas Cardiology Consultants	L04997	Dallas	17	12/11/00
Dallas	Syncor International Corporation	L02048	Dallas	100	12/15/00
Dallas	Columbia Hospital at Medical City Dallas Subsidiary LP	L01976	Dallas	128	12/15/00
Deer Park	Atofina Petrochemicals Inc	L00302	Deer Park	39	12/04/00
Denton	International Isotopes Inc	L05282	Denton	01	12/05/00
Denton	International Isotopes Inc	L05159	Denton	15	12/05/00

CONTINUED AMENDMENTS TO EXISTING LICENSES ISSUED:

Location	Name	License #	City	Amendment #	Date of Action
DFW Airport	Cartier Inc	L05047	DFW Airport	02	11/30/00
DFW Airport	Delta Air Lines Inc	L03967	DFW Airport	16	12/01/00
Edna	Jackson County Hospital District	L04842	Edna	05	12/12/00
El Paso	Biotech Pharmacy Incorporated	L05335	El Paso	01	12/08/00
El Paso	Tenet Hospitals Limited	L04758	El Paso	11	12/18/00
Fredericksburg	Fredericksburg Imaging Center	L03516	Fredericksburg	21	12/02/00
Harlingen	Physician Reliance Network Inc	L00154	Harlingen	28	12/15/00
Houston	Leachman Cardiology Associates	L05229	Houston	02	11/29/00
Houston	Houston Cardiac Electrophysiology Associates	L05090	Houston	02	11/29/00
Houston	Mallinckrodt Medical Inc	L03008	Houston	53	12/06/00
Houston	St Lukes Episcopal Hospital and Texas Heart Inst	L00581	Houston	67	12/06/00
Houston	Memorial Hermann Hospital System	L01168	Houston	57	12/08/00
Houston	Institute Of Biosciences	L04681	Houston	12	12/02/00
Houston	Baker Hughes Oilfield Operations Inc	L05104	Houston	06	12/11/00
Houston	Cardiovascular Ventures of West Houston Inc	L04882	Houston	07	12/13/00
La Porte	Dow Chemical Company USA	L00510	La Porte	61	11/30/00
La Porte	Dow Chemical Company USA	L00510	La Porte	62	12/18/00
Laredo	Mercy Hospital of Laredo	L05305	Laredo	03	12/11/00
Littlefield	Lamb County Hospital	L04973	Littlefield	02	12/12/00
Lubbock	Texas Tech University	L01536	Lubbock	65	12/06/00
Lubbock	Texas Tech University	L01536	Lubbock	66	12/18/00
Marshall	Harrison County Hospital Association	L02572	Marshall	18	12/11/00
McAllen	Valley Cardiology PA	L04692	McAllen	09	12/04/00
Midland	Memorial Hospital and Medical Center	L00728	Midland	65	11/30/00
Mount Pleasant	TXU Electric Monticello Plant	L04565	Mount Pleasant	06	12/14/00
Nacogdoches	Nacogdoches Medical Center	L02853	Nacogdoches	24	12/11/00
Nocona	Nocona Hospital District	L04977	Nocona	04	12/12/00
Pasadena	Celanese LTD Clear Lake Plant	L01130	Pasadena	51	12/14/00
San Antonio	Baptist Imaging Center	L04506	San Antonio	23	12/04/00
San Antonio	Bionumerik Pharmaceuticals Inc	L05226	San Antonio	05	12/05/00
San Antonio	Alamo Cement Co LTD	L04951	San Antonio	03	12/08/00
San Antonio	K O Steel Company	L04480	San Antonio	13	12/08/00
San Antonio	Medical and Radiation Physics Inc	L01417	San Antonio	18	12/11/00
San Antonio	Baptist Health System	L00455	San Antonio	96	12/14/00
Texarkana	Christus Health Ark-La-Tex	L04805	Texarkana	10	11/28/00
Texarkana	Texarkana Memorial Hospital Inc	L02486	Texarkana	32	12/12/00
The Woodlands	Lexicon Genetics Incorporated	L04932	The Woodlands	05	12/05/00
The Woodlands	Memorial Hospital The Woodlands	L03772	The Woodlands	27	12/12/00
Throughout Tx	City of Amarillo Department of Engineering	L02320	Amarillo	14	12/14/00
Throughout Tx	MFG Inc	L05260	Austin	02	11/30/00
Throughout Tx	Omalley Engineers	L02310	Brenham	17	12/14/00
Throughout Tx	Shell Oil Products-Deer Park Refining-Equilon Enterprises LLC	L04554	Deer Park	14	12/14/00
Throughout Tx	Oceaneering International Inc	L04463	Houston	24	11/30/00
Throughout Tx	Metco	L03018	Houston	104	11/30/00
Throughout Tx	Scientific Drilling International	L05105	Houston	03	11/30/00

CONTINUED AMENDMENTS TO EXISTING LICENSES ISSUED:

Location	Name	License #	City	Amend ment #	Date of Action
Throughout Tx	Mandes Inspection & Testing Services Inc	L05220	Houston	17	12/14/00
Throughout Tx	High Tech Testing Service Inc	L05021	Longview	30	11/30/00
Throughout Tx	Anatec Inc	L04865	Nederland	37	12/01/00
Throughout Tx	Big State X-Ray	L02693	Odessa	33	11/30/00
Throughout Tx	Superior Testing Services	L05145	Pasadena	16	12/07/00
Throughout Tx	H B Zachry Company	L01995	San Antonio	20	12/18/00
Tomball	Tomball Hospital Authority	L02514	Tomball	23	11/29/00
Wichita Falls	North Texas Isotopes	L04810	Wichita Falls	06	12/11/00

RENEWALS OF EXISTING LICENSES ISSUED:

Location	Name	License #	City	Amend ment #	Date of Action
Baytown	Baycoast Medical Center	L02462	Baytown	32	12/04/00
Beaumont	BASF Corporation	L02016	Beaumont	20	12/07/00
Beaumont	The Baptist Hospital of South East Texas	L00821	Beaumont	28	12/07/00
Carrollton	Philips Lighting Company	L03823	Carrollton	11	11/30/00
Cuero	Cuero Community Hospital	L02448	Cuero	18	12/11/00
Dallas	GAF Materials Corporation	L03811	Dallas	09	11/30/00
Fredericksburg	Fredericksburg Imaging Center	L03516	Fredericksburg	20	12/07/00
Mesquite	Mesquite Community Hospital LP	L02733	Mesquite	30	12/12/00
Midland	Texas Oncology PA DBA Allison Cancer Center	L04905	Midland	03	11/30/00
San Antonio	Central Cardiovascular Institute of San Antonio	L04892	San Antonio	07	11/29/00
San Antonio	Texas Center For Infectious Disease	L02218	San Antonio	26	12/15/00
Throughout Tx	General Inspection Services Inc	L02319	Hempstead	32	12/13/00
Throughout Tx	Industrial Fabricators Inc	L04935	Texas City	13	12/08/00
Waco	Baylor University	L00343	Waco	14	11/30/00

TERMINATIONS OF LICENSES ISSUED:

Location	Name	License #	City	Amend ment #	Date of Action
Dallas	Terranext Inc	L04965	Dallas	01	11/30/00
Denton	International Isotopes Inc	L04994	Denton	18	12/11/00
Grand Prairie	Dallas Fort Worth Medical Central Grand Prairie	L02612	Grand Prairie	34	12/08/00
San Antonio	Genetex Incorporated	L05255	San Antonio	01	12/11/00
Throughout Tx	Garves W Yates & Sons Inc	L05203	Abilene	01	12/14/00
Throughout Tx	Soiltech Testing Engineers	L04653	Houston	02	12/14/00

LICENSE RENEWAL DENIED:

Location	Name	License #	City	Amendm ent #	Date of Action
Houston	Bandy & Associates	L04296	Houston		12/13/00

LICENSE EXEMPTION ISSUED:

Location	Name	License #	City	Amendm ent #	Date of Action
Kilgore	Woolley Fishing Tool Inc	2915	Kilgore		12/13/00

graphic

[graphic]

In issuing new licenses and amending and renewing existing licenses, the Texas Department of Health, Bureau of Radiation Control, has determined that the applicants are qualified by reason of training and experience to use the material in question for the purposes requested in accordance with Title 25 Texas Administrative Code (TAC) Chapter 289 in such a manner as to minimize danger to public health and safety or property and the environment; the applicants' proposed equipment, facilities and procedures are adequate to minimize danger to public health and safety or property and the environment; the issuance of the license(s) will not be inimical to the health and safety of the public or the environment; and the applicants satisfy any applicable requirements of 25 TAC Chapter 289.

This notice affords the opportunity for a hearing on written request of a licensee, applicant, or "person affected" within 30 days of the date of publication of this notice. A "person affected" is defined as a person who is a resident of a county, or a county adjacent to the county, in which the radioactive materials are or will be located, including any person who is doing business or who has a legal interest in land in the county or adjacent county, and any local government in the county; and who can demonstrate that he has suffered or will suffer actual injury or economic damage. A licensee, applicant, or "person affected" may request a hearing by writing Richard A. Ratliff, P.E., Chief, Bureau of Radiation Control (Director, Radiation Control Program), Texas Department of Health, 1100 West 49th Street, Austin, Texas 78756-3189. For information call (512) 834-6688.

TRD-200009068
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: December 28, 2000

♦ ♦ ♦

Notice of Request for Proposals for Human Immunodeficiency Virus Administrative Agencies

Introduction and Purpose

The Texas Department of Health (department) announces the availability of grant funds to provide administration of outpatient health care and social services to persons with Human Immunodeficiency Virus (HIV) and Acquired Immunodeficiency Syndrome (AIDS) within the new HIV planning areas, (see planning area information at the website at http://www.tdh.state.tx.us/hivstd/pdf/planarea.pdf). Details on areas to be served will be available at the website in mid January, 2001.

Through this Request for Proposals (RFP), the department intends to select up to seven administrative agencies (AA) to provide administration of the following department grant programs:

Title II of the Ryan White Comprehensive AIDS Resources Emergency (CARE) Act of 2000, as amended

HIV State Health and Social Services (State Services)

Housing Opportunities for Persons with AIDS (HOPWA)

The department will enter into contracts with the selected administrative agencies on or about September 1, 2001 for the State Services and HIV CARE Consortia contracts, and on or about February 1, 2002 for HOPWA.

In addition, the department will contract with some of the selected AA's to provide:

Planning Body Coordination.

One entity selected to serve as the administrative agency for each area HIV care planning body (formerly Consortium) will also serve as the administrative body to coordinate the planning functions of the area planning bodies through a memorandum of understanding with the planning body and will receive additional department funding for those activities.

The primary role of an administrative agency is to apply for and manage department funds and programs for the provision of HIV services within the planning area. The department will provide funding for administrative purposes. The remainder of the grant funds will be used by the administrative agency to subcontract with provider agencies which will directly serve persons with HIV infection.

Eligible Applicants

Eligible applicants are public or private nonprofit organizations within the proposed Area of service. Agencies that have had state or federal contracts terminated within the last 24 months for deficiencies in fiscal or programmatic performance are not eligible to apply.

Eligible entities must demonstrate core administrative agency competencies as listed in the Site Review Tool for Assessing Administrative Agency Core Competencies available with the RFP.

To Apply

A letter of intent to apply must be submitted by February 28, 2001, and proposals must be submitted by April 2, 2001. Interested parties may obtain a copy of the RFP at the website: http://www.tdh.state.tx.us/hivstd/grants/default.htm; or, contact Laura Ramos at (512) 490-2525 or by e-mail at laura.ramos@tdh.state.tx.us. No copies of the RFP will be released prior to January 31, 2001.

TRD-200009069
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: December 28, 2000

♦ ♦ ♦

Texas Department of Insurance

Insurer Services

Application to change the name of GUARANTY NATIONAL INSURANCE COMPANY OF CALIFORNIA to GUARANTY NATIONAL INSURANCE COMPANY OF CONNECTICUT, a foreign fire and casualty company. The home office is in Farmington, Connecticut.

Application to change the name of MISSION AMERICAN LIFE INSURANCE COMPANY to GUARANTY INSURANCE AND ANNUITIES COMPANY, a domestic life company. The home office is in Houston, Texas.

Any objections must be filed with the Texas Department of Insurance, addressed to the attention of Godwin Ohaechesi, 333 Guadalupe Street, M/C 305-2C, Austin, Texas 78701.

TRD-200100036
Judy Woolley
Deputy Chief Clerk
Texas Department of Insurance
Filed: January 3, 2001

♦ ♦ ♦

Notice

The Texas Department of Insurance (TDI) has withdrawn from consideration for permanent adoption proposed amendments to the Texas Private Passenger Automobile Statistical Plan (statistical plan). The proposed amendments, which were based on a TDI staff petition, would have amended the use of an existing statistical data field to collect statistical experience concerning the use of rating tiers by direct writing county mutual companies. Notice of the amendments, which were proposed pursuant to Texas Insurance Code Art. 5.96, was published in the *Texas Register* on July 21, 2000 (25 TexReg 6983).

TDI has withdrawn the proposed action after careful consideration of the comments submitted in writing and at a public hearing held on August 31, 2000, under Docket Number 2451. At that hearing TDI's authority to require the reporting of rating tier data from these non rate regulated companies was questioned by affected insurers. Because of some uncertainty in this area, the department has included in its biennial report to the Legislature, required by Texas Insurance Code Sec. 32.022, a proposal that the Insurance Code be amended to clarify the agency's authority to gather statistical data from county mutual companies. This would resolve the issue and enable the department to collect useful information regarding the automobile insurance market in Texas. For these reasons, TDI will not pursue further action on the proposed amendments to the statistical plan, pending any action by the 77th Legislature.

TRD-200100041
Judy Woolley
Deputy Chief Clerk
Texas Department of Insurance
Filed: January 3, 2001

♦ ♦ ♦

Notice

The Commissioner of Insurance, or his designee, will consider approval of a rate filing request submitted by The Travelers Indemnity Company proposing to use rates for private passenger automobile insurance that are outside the upper or lower limits of the flexibility band promulgated by the Commissioner of Insurance, pursuant to TEX. INS. CODE ANN. art 5.101 §3(g). The Company is requesting a flex percent of +55% for liability and physical damage for all territories and classifications. The overall rate change is +19.2% from the previous filing.

Copies of the filing may be obtained by contacting George Russell, at the Texas Department of Insurance, Automobile/Homeowners Division, P.O. Box 149104, Austin, Texas 78714-9104, telephone (512) 305-7468.

This filing is subject to Department approval without a hearing unless a properly filed objection, pursuant to art. 5.101 §3(h), is made with the Chief Actuary for P&C, Mr. Phil Presley, at the Texas Department of Insurance, MC 105-5F, P.O. Box 149104, Austin, Texas 78701, by January 29, 2001.

TRD-200100043
Judy Woolley
Deputy Chief Clerk
Texas Department of Insurance
Filed: January 3, 2001

♦ ♦ ♦

Notice of Applications by Small Employer Carriers to be Risk-Assuming Carriers

Notice is given to the public of the application of the listed small employer carriers to be risk-assuming carriers under Texas Insurance Code Article 26.52. A small employer carrier is defined by Chapter 26 of the Texas Insurance Code as a health insurance carrier that offers, delivers or issues for delivery, or renews small employer health benefit plans subject to the chapter. A risk-assuming carrier is defined by Chapter 26 of the Texas Insurance Code as a small employer carrier that elects not to participate in the Texas Health Reinsurance System. The following small employer carriers have applied to be risk-assuming carriers:

PacifiCare Life Assurance Company, and

Harris Methodist Health Insurance Company

The applications are subject to public inspection at the offices of the Texas Department of Insurance, Financial Monitoring Unit, 333 Guadalupe, Hobby Tower 3, 3rd Floor, Austin, Texas.

If you wish to comment on these applications to be risk-assuming carriers, you must submit your written comments within 60 days after publication of this notice in the Texas Register to Lynda H. Nesenholtz, Chief Clerk, Mail Code 113-1C, Texas Department of Insurance, P. O. Box 149104, Austin, Texas 78714-91204. An additional copy of the comments must be submitted to Mike Boerner, Managing Actuary, Actuarial Division of the Financial Program, Mail Code 304-3A, Texas Department of Insurance, P. O. Box 149104, Austin, Texas 78714-9104. Upon consideration of the applications, if the Commissioner is satisfied that all requirements of law have been met, the Commissioner or his designee may take action to approve the applications to be risk-assuming carriers.

TRD-200009052
Judy Woolley
Deputy Chief Clerk
Texas Department of Insurance
Filed: December 28, 2000

♦ ♦ ♦

Notice of Filing

The following petition has been filed with the Texas Department of Insurance, and is under consideration:

The adoption of two amendments to the Plan of Operation for Texas Automobile Insurance Plan Association (TAIPA), pursuant to Article 21.81.

One proposal is to amend the TAIPA Plan of Operation, Section 13.B.2. to delete the specific reference to the Installment Premium Payment Option and to make a general reference to all payment options outlined in Section 5 (which includes the installment option). TAIPA requests this amendment because the eight-payment installment plan is available for commercial assignments effective January l, 2001.

The other proposal is to amend the TAIPA Plan of Operation, Section 15.D. to change the word "quotas" to "assessments" to be consistent with the wording in Section 15.B., which requires that assessments be based on data for the second prior year. This amendment does not affect the current method of calculating assessments.

This filing is subject to Department approval without a hearing. Any comments may be filed with Marilyn Hamilton, Deputy Commissioner, Personal and Commercial Lines Division, Texas Department of Insurance, Mail Code 104-PC, P.O. Box 149104, Austin, Texas 78714-9104, within 15 days after publication of this notice.

For further information or to request a copy of the proposed amendments, please contact Sylvia Gutierrez at (512) 463-6327 (reference number A-0900-23).

TRD-200100037
Judy Woolley
Deputy Chief Clerk
Texas Department of Insurance
Filed: January 3, 2001

♦ ♦ ♦

Texas Department of Mental Health and Mental Retardation

Public Notice Announcing Pre-Application Orientation for Waiver Program Provider Enrollment

The Texas Department of Mental Health and Mental Retardation (TDMHMR), pursuant to 25 TAC §419.704, will hold a Pre-Application Orientation (PAO) for persons seeking to participate as a program provider in the Home and Community-Based Services (HCS), Home and Community-Based Services-OBRA (HCS-O), or Mental Retardation Local Authority (MRLA).

The PAO will be held at 8:30 a.m., Monday, April 16, 2001, in Austin, Texas. Persons wanting to attend the PAO must request a registration form by letter or by fax. Requests should be addressed to Bill Fordyce, Enrollment/Sanctions Manager, Medicaid Administration, TDMHMR, PO Box 12668, Austin, Texas 78711-2668. The fax number is (512) 206-5725.

Upon receipt of a written request, TDMHMR will provide the applicant with information regarding the provider application enrollment processes and a registration form to the requestor. Completed registration forms must be returned to TDMHMR no later than 5:00 p.m., Friday, March 16, 2001. Written requests for a registration form received after March 9, 2001, may not be timely enough to meet the March 16, 2001, registration form return date. If the registration form is not returned to TDMHMR by March 16, 2001, the form is invalid and the applicant will be required to reapply when the next PAO is announced.

Persons requiring an interpreter for the deaf or hearing impaired or other accommodation should contact Helen Rayner by calling (512) 206-5249 or the TTY phone number of Texas Relay, which is 1-800-735-2988, at least 72 hours prior to the PAO. You may also contact Helen Rayner for additional information concerning the PAO.

TRD-200100040
Andrew Hardin
Chairman, Texas MHMR Board
Texas Department of Mental Health and Mental Retardation
Filed: January 3, 2001

♦ ♦ ♦

Texas State Board of Pharmacy

Correction of Error

The Texas State Board of Pharmacy filed proposed rule reviews for Chapter 291 (§291.23) and Chapter 295 (§295.13) for publication in the December 29, 2000, issue of the *Texas Register*.

Due to an error by the Texas Register the proposed rule reviews were omitted from the issue and the adopted rule reviews for Chapter 291 (§§291.71-291.76) and Chapter 295 (§295.11) were published instead. The proposed rule reviews are in the Rule Review section of this issue of the *Texas Register*.

TRD-200100044

♦ ♦ ♦

Public Utility Commission of Texas

Correction of Error

The Public Utility Commission adopted new 16 TAC §26.24 relating to Credit Requirements and Deposits. The rule appeared in the December 22, 2000 *Texas Register* (25 TexReg 12652).

Due to an error by the *Texas Register* the reference to subparagraph "(B)" was omitted on page 12675 under §26.24(a)(1)(C). As published subparagraph (C) reads:

"(C) The DCTU may require the applicant to pay a deposit only if the applicant does not demonstrate satisfactory credit using the criteria in subparagraph of this paragraph."

The subparagraph should read as follows.

"(C) The DCTU may require the applicant to pay a deposit only if the applicant does not demonstrate satisfactory credit using the criteria in subparagraph (B) of this paragraph."

TRD-200100030

♦ ♦ ♦

Notice of Application for a Certificate of Convenience and Necessity for a Proposed Transmission Line

Notice is given to the public of the filing with the Public Utility Commission of Texas (commission) of an application on December 15, 2000, for a certificate of convenience and necessity for a proposed transmission line in Montgomery County pursuant to P.U.C. Substantive Rule §25.101(c)(1)(C), §§14.001, 37.051, 37.054, 37.056 and 37.057 of the Public Utility Regulatory Act, Texas Utilities Code Annotated (Vernon 1998 & Supplement 2000) (PURA). A summary of the application follows.

00Docket Style and Number: Application of Entergy Gulf States, Inc. for a Certificate of Convenience and Necessity (CCN) for Proposed Transmission Line within Montgomery County, Docket Number 23429.

The Application: Entergy Gulf States, Inc. (EGSI) filed an application for a certificate for convenience and necessity (CCN) for a proposed transmission line. To provide adequate and reliable service to a rapid load growth in south central Montgomery County, EGSI will require a new 138 kV connection between Conroe Bulk and Goslin Substations, thus providing an additional transmission source into the area. To achieve this connection, a new transmission line is proposed to be constructed between Conroe Bulk Substation and the site of a future substation located near the end of de-engerized 138 kV Line 403, which is connected to Goslin Substation. A section of Line 403 will be re-energized to connect Conroe Bulk Substation to Goslin Substation. In addition, Line 587 from Lewis Creek Steam Electric Station to Conroe Bulk Substation should be upgraded.

Persons who wish to comment upon the action sought should contact the Public Utility Commission of Texas, P. O. Box 13326, Austin, Texas 78711-3326, or call the commission's Customer Protection Division at (512) 936-7120 or (888) 782-8477. Hearing and speech- impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136 or use Relay Texas (toll-free) 1-800-735-2989. The deadline for intervention in the proceeding will be established. The commission should receive a letter requesting intervention on or before the intervention deadline.

TRD-200100019
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: January 2, 2001

♦ ♦ ♦

Texas Department of Transportation

Public Notice

In accordance with 43 TAC §§11.200-11.205, the Texas Department of Transportation issues this 2001 Program Call for the proposed projects of the department's Statewide Transportation Enhancement Program.

Title 23, United States Code, §133 (d)(2) and §160(e) (2), requires that 10% of certain funds apportioned a state pursuant to Title 23, United States Code §104((b) (3), be used for transportation enhancement activities, as defined. The Texas Transportation Commission may allocate funds to the department for use on the state highway system for transportation enhancement activities that provide a safe, effective and efficient movement of people and goods. The commission will also make funds available in a statewide competitive program that enhances the surface transportation systems and facilities within the state for the benefit of the users of those systems.

Transportation enhancement activities are defined in §101(a) of Title 23, United States Code as:

(1) provision of facilities for pedestrians and bicycles;

(2) provision of safety and education activities for pedestrians and bicycles;

(3) acquisition of scenic easements and scenic or historic sites;

(4) scenic or historic highway program (including the provision of tourist and welcome center facilities);

(5) landscaping and other scenic beautification;

(6) historic preservation;

(7) rehabilitation and operation of historic transportation buildings, structures or facilities (including historic railroad facilities and canals);

(8) preservation of abandoned railway corridors (including the conversion and use thereof for pedestrian or bicycle trails);

(9) control & removal of outdoor advertising;

(10) archaeological planning & research;

(11) environmental mitigation to address water pollution due to highway runoff or reduce vehicle-caused wildlife mortality while maintaining habitat connectivity; and establishment of transportation museums.

To nominate a project, the eligible nominating entity must file its nomination, in the form prescribed by the department, with the district engineer of the district office responsible for the area in which the proposed enhancement project will be implemented. The address and telephone number of the district offices may be obtained by contacting the Design Division at (512) 416-3082. Completed nominations must be received by the department no later than 5:00 p.m., Monday, June 18, 2001.

Information regarding the program, program guide, nomination forms and workshops are available from the department's district offices or by writing the Design Division, 125 East 11th Street, Austin, Texas 78701-2483.

TRD-200100014
Bob Jackson
Deputy General Counsel
Texas Department of Transportation
Filed: January 2, 2001

♦ ♦ ♦

Texas Water Development Board

Applications Received

Pursuant to the Texas Water Code, Section 6.195, the Texas Water Development Board provides notice of the following applications received by the Board:

Galveston County Water Control and Improvement District No. 12, 524 Cien Street, Kemah, Texas, 77565, received November 30, 2000, application for financial assistance in the amount of $3,425,000 from the Texas Water Development Funds.

Sandy Land Underground Water Conservation District, P.O. Box 130, Plains, Texas 79355, received December 14, 2000, application for financial assistance in the amount of $500,000 from the Agricultural Water Conservation Loan Program.

Daniel B. Stephens & Associates, Inc. 6020 Academy NE, Suite 100, Albuquerque, New Mexico, 87109, application for financial assistance in an amount not to exceed $549,927 from the Research and Planning Fund.

Duke Engineering & Services, Inc., 9111 Research Blvd., Austin, Texas, 78758, application for financial assistance in an amount not to exceed $699,806.41 from the Research and Planning Fund.

Duke Engineering & Services, Inc., 9111 Research Blvd., Austin, Texas, 78758, application for financial assistance in an amount not to exceed $550,000 from the Research and Planning Fund.

University of Texas at Austin, Bureau of Economic Geology, Box 7726, University Station, Austin, Texas, 78713, application for financial assistance in an amount not to exceed $549,486 from the Research and Planning Fund.

Waterstone Environmental Hydrology and Engineering, Inc., 1650 38th Street, Suite 201E, Boulder, Colorado, 80301, application for financial assistance in an amount not to exceed $550,000 from the Research and Planning Fund.

Angelina and Neches River Authority, P.O. Box 387, Lukfin, Texas, 75901, application for financial assistance in an amount not to exceed $451,000 from the Research and Planning Fund.

North Texas Municipal Water District, P.O. Box 2408, Wylie, Texas, 75098-2408, application for financial assistance in an amount not to exceed $227,200 from the Research and Planning Fund.

TRD-200100035
Gail L. Allan
Director of Project-Related Legal Services
Texas Water Development Board
Filed: January 3, 2001

♦ ♦ ♦

How to Use the Texas Register

Information Available: The 13 sections of the ***Texas Register*** represent various facets of state government. Documents contained within them include:

Governor - Appointments, executive orders, and proclamations.

Attorney General - summaries of requests for opinions, opinions, and open records decisions.

Secretary of State - opinions based on the election laws.

Texas Ethics Commission - summaries of requests for opinions and opinions.

Emergency Rules- sections adopted by state agencies on an emergency basis.

Proposed Rules - sections proposed for adoption.

Withdrawn Rules - sections withdrawn by state agencies from consideration for adoption, or automatically withdrawn by the Texas Register six months after the proposal publication date.

Adopted Rules - sections adopted following a 30-day public comment period.

Texas Department of Insurance Exempt Filings - notices of actions taken by the Texas Department of Insurance pursuant to Chapter 5, Subchapter L of the Insurance Code.

Texas Department of Banking - opinions and exempt rules filed by the Texas Department of Banking.

Tables and Graphics - graphic material from the proposed, emergency and adopted sections.

Open Meetings - notices of open meetings.

In Addition - miscellaneous information required to be published by statute or provided as a public service.

Review of Agency Rules - notices of state agency rules review.

Specific explanation on the contents of each section can be found on the beginning page of the section. The division also publishes cumulative quarterly and annual indexes to aid in researching material published.

How to Cite: Material published in the ***Texas Register*** is referenced by citing the volume in which the document appears, the words "TexReg" and the beginning page number on which that document was published. For example, a document published on page 2402 of Volume 26 (2001) is cited as follows: 26 TexReg 2402.

In order that readers may cite material more easily, page numbers are now written as citations. Example: on page 2 in the lower-left hand corner of the page, would be written "26 TexReg 2 issue date," while on the opposite page, page 3, in the lower right-hand corner, would be written "issue date 26 TexReg 3."

How to Research: The public is invited to research rules and information of interest between 8 a.m. and 5 p.m. weekdays at the ***Texas Register*** office, Room 245, James Earl Rudder Building, 1019 Brazos, Austin. Material can be found using ***Texas Register*** indexes, the ***Texas Administrative Code***, section numbers, or TRD number.

Both the ***Texas Register*** and the ***Texas Administrative Code*** are available online through the Internet. The address is: http://www.sos.state.tx.us. The ***Register*** is available in an .html version as well as a .pdf (portable document format) version through the Internet. For subscription information, see the back cover or call the Texas Register at (800) 226-7199.

Texas Administrative Code

The ***Texas Administrative Code (TAC)*** is the compilation of all final state agency rules published in the ***Texas Register***. Following its effective date, a rule is entered into the ***Texas Administrative Code***. Emergency rules, which may be adopted by an agency on an interim basis, are not codified within the ***TAC***.

The ***TAC*** volumes are arranged into Titles (using Arabic numerals) and Parts (using Roman numerals). The Titles are broad subject categories into which the agencies are grouped as a matter of convenience. Each Part represents an individual state agency.

The complete TAC is available through the Secretary of State's website at http://www.sos.state.tx.us/tac. The following companies also provide complete copies of the TAC: Lexis-Nexis (1-800-356-6548), and West Publishing Company (1-800-328-9352).

The Titles of the ***TAC***, and their respective Title numbers are:

1. Administration
4. Agriculture
7. Banking and Securities
10. Community Development
13. Cultural Resources
16. Economic Regulation
19. Education
22. Examining Boards
25. Health Services
28. Insurance
30. Environmental Quality
31. Natural Resources and Conservation
34. Public Finance
37. Public Safety and Corrections
40. Social Services and Assistance
43. Transportation

How to Cite: Under the ***TAC*** scheme, each section is designated by a ***TAC*** number. For example in the citation 1 TAC §27.15:

1 indicates the title under which the agency appears in the ***Texas Administrative Code***; ***TAC*** stands for the ***Texas Administrative Code***; §27.15 is the section number of the rule (27 indicates that the section is under Chapter 27 of Title 1; 15 represents the individual section within the chapter).

How to update: To find out if a rule has changed since the publication of the current supplement to the ***Texas Administrative Code***, please look at the ***Table of TAC Titles Affected***. The table is published cumulatively in the blue-cover quarterly indexes to the ***Texas Register*** (January 19, April 13, July 13, and October 12, 2001). If a rule has changed during the time period covered by the table, the rule's ***TAC*** number will be printed with one or more ***Texas Register*** page numbers, as shown in the following example.

TITLE 40. SOCIAL SERVICES AND ASSISTANCE

Part I. Texas Department of Human Services

40 TAC §3.704..............950, 1820

The ***Table of TAC Titles Affected*** is cumulative for each volume of the ***Texas Register*** (calendar year).

Texas Register
Services

The *Texas Register* offers the following services. Please check the appropriate box (or boxes).

Texas Natural Resource Conservation Commission, Title 30
❑ **Chapter 285** $25 ❑ update service $25/year *(On-Site Wastewater Treatment)*
❑ **Chapter 290** $25 ❑ update service $25/year *(Water Hygiene)*
❑ **Chapter 330** $50 ❑ update service $25/year *(Municipal Solid Waste)*
❑ **Chapter 334** $40 ❑ update service $25/year *(Underground/Aboveground Storage Tanks)*
❑ **Chapter 335** $30 ❑ update service $25/year *(Industrial Solid Waste/Municipal Hazardous Waste)*
Update service should be in ❑ printed format ❑ 3 1/2" diskette

Texas Workers Compensation Commission, Title 28
❑ Update service $25/year

Texas Register Phone Numbers	**(800) 226-7199**
Documents	(512) 463-5561
Circulation	(512) 463-5575
Marketing	(512) 305-9623
Texas Administrative Code	(512) 463-5565

Information For Other Divisions of the Secretary of State's Office	
Executive Offices	(512) 463-5701
Corporations/	
Copies and Certifications	(512) 463-5578
Direct Access	(512) 475-2755
Information	(512) 463-5555
Legal Staff	(512) 463-5586
Name Availability	(512) 463-5555
Trademarks	(512) 463-5576
Elections	
Information	(512) 463-5650
Statutory Documents	
Legislation	(512) 463-0872
Notary Public	(512) 463-5705
Uniform Commercial Code	
Information	(512) 475-2700
Financing Statements	(512) 475-2703
Financing Statement Changes	(512) 475-2704
UCC Lien Searches/Certificates	(512) 475-2705

Please use this form to order a subscription to the *Texas Register*, to order a back issue, or to indicate a change of address. Please specify the exact dates and quantities of the back issues required. You may use your VISA or Mastercard. All purchases made by credit card will be subject to an additional 2.1% service charge. Return this form to the Texas Register, P.O. Box 13824, Austin, Texas 78711-3824. For more information, please call (800) 226-7199.

❒ **Change of Address**
(Please fill out information below)

❒ **Paper Subscription**
❒ One Year $150 ❒ Six Months $100 ❒ First Class Mail $250

❒ **Back Issue ($10 per copy)**

________ Quantity

Volume ________, Issue #_______.
(Prepayment required for back issues)

NAME ____

ORGANIZATION____

ADDRESS ____

CITY, STATE, ZIP ____

PHONE NUMBER ____

FAX NUMBER ____

Customer ID Number/Subscription Number ______________________________
(Number for change of address only)

❒ **Bill Me** ❒ **Payment Enclosed**

Mastercard/VISA Number ____

Expiration Date ____________ Signature _______________________________

Please make checks payable to the Secretary of State. Subscription fees are not refundable.
Do not use this form to renew subscriptions.
Visit our home on the internet at http://www.sos.state.tx.us.

Periodical Postage

PAID

Austin, Texas
and additonal entry offices