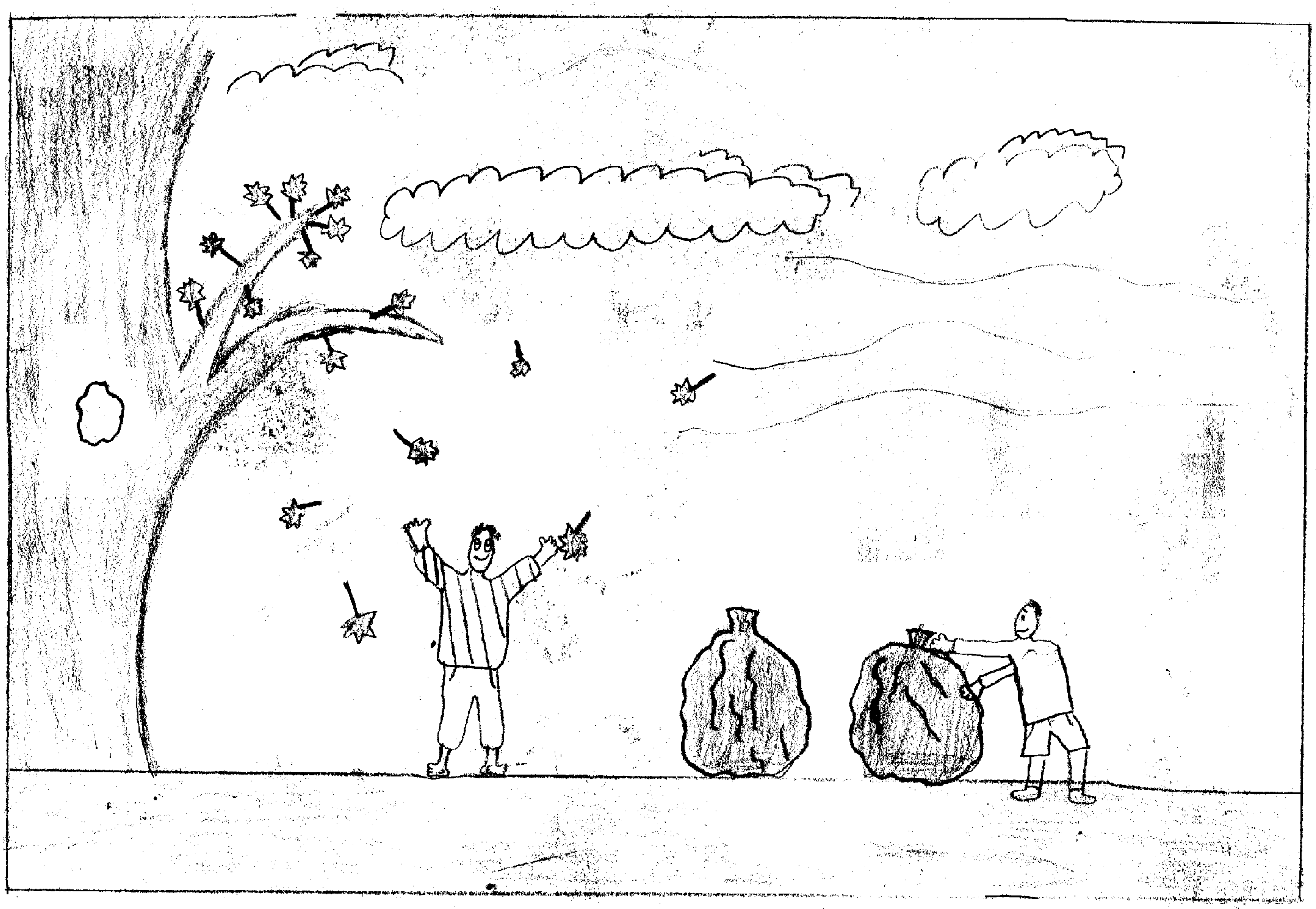
# Texas Register

*Volume 26 Number 41 October 12, 2001 Pages 7949 - 8244*



***This month's front cover artwork:***

***Artist:*** *Andrew Miller*

*5th Grade*

*K. Smith Elementary*

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.

Material in the ***Texas Register*** is the property of the State of Texas. However, it may be copied, reproduced, or republished by any person without permission of the ***Texas Register*** Director, provided no such republication shall bear the legend ***Texas Register*** or "Official" without the written permission of the director.

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

**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

**Director** - Dan Procter

**Customer Relations**
Leti Benavides
LaKiza Fowler-Sibley

***Texas Administrative Code***
Dana Blanton
Roberta Knight

***Texas Register***
Carla Carter
Melissa Dix
Kris Hogan
Diana Muniz-Franklin

**Circulation/Marketing**
Jill S. Ledbetter

## GOVERNOR



## ATTORNEY GENERAL



## EMERGENCY RULES



## PROPOSED RULES

# Open Meetings

A notice of a meeting filed with the Secretary of State by a state governmental body or the governing body of a water district or other district or political subdivision that extends into four or more counties is posted at the main office of the Secretary of State in the lobby of the James Earl Rudder Building, 1019 Brazos, Austin, Texas.

Notices are published in the electronic *Texas Register* and available on-line. http://www.sos.state.tx.us/texreg

To request a copy of a meeting notice by telephone, please call 463-5561 if calling in Austin. For out-of-town callers our toll-free number is (800) 226-7199. Or fax your request to (512) 463-5569.

Information about the Texas open meetings law is available from the Office of the Attorney General. The web site is http://www.oag.state.tx.us. Or phone the Attorney General's Open Government hotline, (512) 478-OPEN (478-6736).

For on-line links to information about the Texas Legislature, county governments, city governments, and other government information not available here, please refer to this on-line site. http://www.state.tx.us/Government

•••

**Meeting Accessibility.** Under the Americans with Disabilities Act, an individual with a disability must have equal opportunity for effective communication and participation in public meetings. Upon request, agencies must provide auxiliary aids and services, such as interpreters for the deaf and hearing impaired, readers, large print or Braille documents. In determining type of auxiliary aid or service, agencies must give primary consideration to the individual's request. Those requesting auxiliary aids or services should notify the contact person listed on the meeting notice several days before the meeting by mail, telephone, or RELAY Texas. TTY: 7-1-1.

# THE GOVERNOR

As required by Texas Civil Statutes, Article 6252-13a, §6, the ***Texas Register*** publishes executive orders issued by the Governor of Texas. Appointments and proclamations are also published. Appointments are published in chronological order. Additional information on documents submitted for publication by the Governor's Office can be obtained by calling (512) 463-1828.

Appointments

**Appointments for September 11, 2001**

Appointed to the Board of Protective and Regulatory Services for terms to expire February 1, 2007, John R. Castle, Jr. of Dallas (replaced Jon Bradley of Dallas whose term expired) and Ann C. Crews of Dallas (replaced Maureen Dickey of Dallas whose term expired).

Designated as presiding officer of the Board of Protective and Regulatory Services for a term at the pleasure of the Governor, Richard S. Hoffman of Brownsville (replaced Catherine Mosbacher who continues to serve on the board).

Appointed as Public Counsel for the Office of Public Insurance Counsel for a term to expire February 1, 2003, Roderick A. Bordelon, Jr. of Austin (reappointed).

Designated as presiding officer of the Texas Council on Workforce and Economic Competitiveness for a term at the pleasure of the Governor, Ann F. Hodge of Katy (replaced David Sampson who resigned).

**Appointments for September 12, 2001**

Appointed to the Department of Information Resources Board of Directors for a term to expire February 1, 2007, M. Adam Mahmood, Ph.D. of El Paso (replaced Harry Richardson of San Antonio whose term expired).

Appointed to the Texas Military Facilities Commission for a term to expire April 30, 2007, Brigadier General Michael H. Taylor of Lufkin (replaced Wayne Marty of Austin who was withdrawn from the board).

Appointed to the State Preservation Board for a term to expire February 1, 2003, Jocelyn Levi Straus of San Antonio (replaced Dealey Herndon whose term expired).

Appointed as Presiding Judge of the Eighth Administrative Judicial Region for a term to expire four years from date of qualification, Roger Jeffrey "Jeff" Walker of Arlington (reappointed).

Appointed to the Texas Commission for Volunteerism and Community Service for terms to expire April 1, 2004, Reba Cardenas McNair of Brownsville (reappointed), Francisco G. Zarate of Rio Grande City (reappointed), Carol S. Whittenburg of Amarillo (replaced Nancy Weiss of Lubbock whose term expired), Marcus D. Cosby (replaced Manson B. Johnson of Houston whose term expired), and Robert Horton of Austin (replaced Jan Kennady of New Braunfels whose term expired).

**Appointments for September 14, 2001**

Designating as chair of the Texas Growth Fund Board of Trustees for a term to expire February 1, 2003, J. Michael Bell of Fredericksburg (reappointed).

Appointed to the Texas Department of Housing and Community Affairs pursuant to Senate Bill 322, 77th Legislature:

for terms to expire January 31, 2003, C. Kent Conine of Frisco and Michael E. Jones of Tyler;

for terms to expire January 31, 2005, Shadrick Bogany of Missouri City, Vidal Gonzalez of Del Rio, and Norberto Salinas of Mission;

for a term to expire January 31, 2007, Elizabeth M. Anderson of Dallas.

Designated as Presiding Officer of the Texas Department of Housing and Community Affairs for a term at the pleasure of the Governor, Michael E. Jones (reappointed pursuant to Senate Bill 322, 77th Legislature).

**Appointments for September 18, 2001**

Appointed to the Brazos River Authority Board of Directors:

for a term to expire February 1, 2005, Carolyn H. Johnson of Freeport (replaced Andrew Jackson of Missouri City who resigned);

for terms to expire February 1, 2007, Suzanne Alderson Baker of Lubbock (replaced Ruth Schiermeyer of Lubbock whose term expired), Ronald D. Butler, II of Stephenville (replaced C.J. Farrar of Hico whose term expired), Fred Lee Hughes of Abilene (replaced Deborah Bell of Abilene whose term expired), P.J. Ellison Kalil of Brenham (replaced Ramiro Galindo of Bryan whose term expired), Martha Stovall Martin of Graford (replaced Judy Vernon of Evant whose term expired), John R. Skaggs of Plainview (replaced Linda Kay Lyle of Plainview whose term expired), and Salvatore A. Zaccagnino of Caldwell (replaced Carl Lynn Elliott of College Station whose term expired).

Appointed to the University of North Texas Board of Regents for a term to expire May 22, 2007, Marjorie B. Craft of DeSoto (reappointed), Burle Pettit of Lubbock (reappointed), and John Robert "Bobby" Ray of Plano (reappointed).

**Appointments for September 20, 2001**

Designated as Presiding Officer of the Governing Board of the Texas Department of Economic Development for a term at the pleasure of the Governor, Macedonio "Massey" Villarreal (replaced Mark Langdale of Dallas who continues to serve on the board).

Appointed as State Demographer pursuant to Senate Bill 656, 77th Legislature for a term at the pleasure of the Governor, Steve Murdock, Ph.D. of College Station.

Appointed to the Texas Interagency Council on Early Childhood Intervention Advisory Committee for terms to expire February 1, 2007, Julia Alderman-Patty of Fort Worth (reappointed), Clair E. Balliett of Longview (reappointed), Sandra J. Collins of Sugar Land (reappointed), Wendy Dietrich Benz of San Antonio (pursuant to IDEA, Part

C, §641), Alba A. Ortiz, Ph.D. of Austin (pursuant to IDEA, Part C, §641), Mabel E. Cartey of Austin (replaced Patricia Carroll of Round Rock whose term expired), and Lynn Davis Sullivan of Fort Worth (replaced Alvin Stewart of Plano whose term expired).

**Appointments for September 21, 2001**

Appointed to the Office of Rural Community Affairs pursuant to House Bill 7, 77th Legislature:

for a term to expire February 1, 2003, Lydia Rangel Saenz of Carrizo Springs;

for a term to expire February 1, 2005, Michael Cooper Waters of Abilene;

for a term to expire February 1, 2007, Wallace G. Klussmann of Fredericksburg.

Appointed to the State Board of Barber Examiners for a term to expire January 31, 2007, San Juana C. Garza of Mercedes (replaced Ernest Pack of Waco whose term expired).

Rick Perry, Governor

TRD-200105867

♦ ♦ ♦

# 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-0411**

The Honorable Jose R. Rodriguez, County Attorney, El Paso County, County Courthouse, 500 East San Antonio, Room 203, El Paso, Texas 79901

Re: Whether the Board of Trustees of the Risk Pool for the El Paso County Health Benefits Program may meet in executive session to consider a complaint against the third party administrator for the program (RQ-0369-JC)

**S U M M A R Y**

The Board of Trustees of the Risk Pool for the El Paso County Health Benefits Program may not deliberate about complaints against its third party administrator in an executive session under the personnel exception to the Texas Open Meetings Act. The third party administrator is not an officer or employee within that exception.

The Standards for Privacy of Individually Identifiable Health Information promulgated under the Health Insurance Portability and Accountability Act of 1996 (the "HIPAA"), Pub. L. No. 104-191, preempt contrary state law. The Board of Trustees of the El Paso County Health Benefits Program should seek advice from the United States Department of Health and Human Services about the application of these standards to the El Paso County Health Benefits Program and to public meetings in which the Board of Trustees deliberates about complaints against its third party administrator involving individually identifiable health information.

**Opinion No. JC-0412**

Charles E. Bell, M.D., Executive Deputy Commissioner, Texas Department of Health, 1100 West 49th Street, Austin, Texas 78756-3199

Re: Whether, in accordance with section 439.022 of the Health and Safety Code, the Texas Board of Health must adopt rules providing for a nursing home to recycle certain prescription drugs that are scheduled to be destroyed (RQ-0371-JC)

**S U M M A R Y**

As the federal Food and Drug Administration interprets applicable federal law, federal law permits, with certain limitations, the collection and shipment to foreign countries of unused prescription drugs that are no longer needed by nursing-home residents, where the drugs are samples or are in the original packaging. In accordance with section 439.022 of the Texas Health and Safety Code, the state Board of Health must adopt regulations that provide for the collecting of such drugs, sample and nonsample, and shipment to foreign countries. See Tex. Health & Safety Code Ann. § 439.022(a) (Vernon 2001). The regulations must comport with federal law, as well as with any other applicable state law. See id.

**Opinion No. JC-0413**

The Honorable Bill Moore, Johnson County Attorney, 2 North Main Street, Cleburne, Texas 76031

Re: Duties of a constable under section 86.021 of the Texas Local Government Code (RQ-0376-JC)

**S U M M A R Y**

Subsections (a) and (e) of section 86.021 of the Texas Local Government Code, mandate two independent duties of a constable, each of which must be fulfilled. Should a constable believe that he has insufficient time to fulfill both duties, he may apply to the commissioners court under section 86.011 of the Local Government Code for the appointment of a deputy.

**Opinion No. JC-0414**

The Honorable Virginia K. Treadwell, McCulloch County Attorney Courthouse, Room 302, Brady, Texas 76825

Re: Whether a county commissioners court is required to provide health insurance for a constable (RQ-0384-JC)

**S U M M A R Y**

McCulloch County provides health insurance to full-time officials and employees who serve the county at least 120 hours a month, but the county does not provide it to part-time and temporary officials and employees. Assuming that the McCulloch County Commissioners Court has reasonably determined on the basis of the constable's constitutional and statutory duties that the constable serves the county part time, it is not required to provide him with health insurance.

**Opinion No. JC-0415**

The Honorable Florence Shapiro, Chair, State Affairs Committee, Texas State Senate, P.O. Box 12068, Austin, Texas 78711

Re: Whether renting a portion of a residence disqualifies that portion for the homestead-tax exemption, and related questions (RQ-0361-JC)

**S U M M A R Y**

The term "temporary," as used in section 11.13(l) of the Tax Code, refers to a limited or short absence of the owner from the "residence homestead." The term "principal residence," as used in that subsection, refers to the owner's primary or chief residence that the owner actually occupies on a regular basis. Section 11.13(k) of the Tax Code, which disallows the residence- homestead-tax exemption with respect to that part of the residence homestead used for a purpose that is "incompatible with the owner's residential use," does not apply when the owner rents the entire residence to another and is absent from the residential homestead. The owner's rental of a part of the residence to another disqualifies that part of the residence from the homestead-tax exemption under subsection (k).

**Opinion No. JC-0416**

The Honorable Rene O. Oliveira, Chair, House Committee on Ways and Means, Texas House of Representatives, P.O. Box 2910, Austin, Texas 78768-2910

Re: Whether the Texas Department of Public Safety has authority to establish and administer a training and safety program for off-road dirt bikes (RQ-0364-JC)

**S U M M A R Y**

The Texas Department of Public Safety is not authorized to establish and administer operator training and safety programs for off-road dirt bikes.

**Opinion No. JC-0417**

Mr. Randall S. James, Banking Commissioner, Texas Department of Banking, 2601 North Lamar, Austin, Texas 78705-4294

Re: Whether the Archdiocese of San Antonio must obtain a permit from the Texas Department of Banking in order to sell prepaid funeral benefits (RQ-0367-JC)

**S U M M A R Y**

The provisions of chapter 154 of the Texas Finance Code are applicable to religious organizations that sell prepaid funeral benefits and do not violate the Establishment Clause or Free Exercise Clause of the First Amendment to the United States Constitution.

*For further information, please call the Opinion Committee at (512) 463-2110.*

TRD-200105858
Susan D. Gusky
Assistant Attorney General
Office of the Attorney General
Filed: September 27, 2001

♦ ♦ ♦

## Request for Opinions

**RQ-0439-JC**

The Honorable Frank Madla, Chair, Intergovernmental Relations Committee, Texas State Senate, P.O. Box 12068, Austin, Texas 78711-2068.

Regarding whether a raffle ticket may be awarded as a prize in a bingo game. (Request No. 0439-JC)

**Briefs requested by October 29, 2001.**

**RQ-0440-JC**

Ms. Sandy Smith, Executive Director, Texas Board of Professional Land Surveying, 7701 North Lamar, Suite 400, Austin, Texas 78752.

Regarding authority of the Texas Board of Professional Land Surveying to require that all proposed well locations be surveyed by a registered professional land surveyor. (Request No. 0440-JC)

**Briefs requested by October 27, 2001.**

**RQ-0441-JC**

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

Regarding whether a political subdivision may prohibit a tow truck from having auxiliary stop and tail lamps in or under the factory mounted light bar, and related question. (Request No. 0441-JC)

**Briefs requested by October 27, 2001.**

**RQ-0442-JC**

The Honorable Michael A. Stafford, Harris County Attorney, 1310 Prairie, Room 940, Houston, Texas 77002.

Regarding meaning of "lifetime service credit" for purposes of House Bill 178, Acts 77th Leg., ch. 378, at 663, which requires longevity pay for certain assistant prosecutors. (Request No. 0442-JC)

**Briefs requested by October 27, 2001.**

*For further information, please call the Opinion Committee at (512) 463-2110.*

TRD-200105975
Susan D. Gusky
Assistant Attorney General
Office of the Attorney General
Filed: October 3, 2001

♦ ♦ ♦

## Withdrawal of Open Records Request

*NOTICE: The following request for decision has been withdrawn by the Office of the Attorney General. Therefore, no formal open records decision will be rendered on the following request:*

**ORQ-50 (ID# 134212)** Re: What constitutes a "business day" or "working day" for purposes of Subchapter G of Chapter 552 of the Government Code?

**For more information, please contact Michael Garbarino at (512) 936-6736.**

TRD-200105976
Susan Gusky
Assistant Attorney General
Office of the Attorney General
Filed: October 3, 2001

♦ ♦ ♦

# EMERGENCY RULES

An agency may adopt a new or amended section or repeal an existing section on an emergency basis if it determines that such action is necessary for the public health, safety, or welfare of this state. The section may become effective immediately upon filing with the ***Texas Register***, or on a stated date less than 20 days after filing and remaining in effect no more than 120 days. The emergency action is renewable once for no more than 60 additional days.

**Symbology in amended emergency sections.** 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 4. AGRICULTURE

## PART 1. TEXAS DEPARTMENT OF AGRICULTURE

### CHAPTER 20. COTTON PEST CONTROL
### SUBCHAPTER C. STALK DESTRUCTION PROGRAM

#### 4 TAC §20.22

The Department of Agriculture (the department) adopts on an emergency basis, an amendment to §20.22, concerning the authorized cotton destruction dates for Pest Management Zone 3, Areas 1 and 2.

The department is acting on behalf of cotton farmers in Zone 3, Areas 1 and 2. The committee recommended the deadline for Matagorda County not be extended because field conditions have been acceptable for destruction activities.

The current cotton destruction deadline for Zone 3, Area 1 is October 1. The cotton destruction deadline will be extended through October 15 for Zone 3, Area 1 (excluding Matagorda County). The current cotton stalk destruction deadline for Zone 3, Area 2 is October 15. The deadline for stalk destruction for Matagorda County remains October 1. The cotton destruction deadline will be extended through October 29 for Zone 3 Area 2. The department believes that changing the cotton destruction dates is both necessary and appropriate. This extension is effective only for the 2001 crop year. Adverse weather conditions have created a situation compelling an immediate extension of the cotton destruction dates for Zone 3, Areas 1 and 2 (excluding Matagorda County). The unusually wet weather prior to the cotton destruction period has prevented many cotton producers from destroying cotton by the October 1 deadline in Zone 3, Area 1 and by October 15 in Zone 3, Area 2. A failure to act to extend the cotton destruction deadline could create a significant economic loss to Texas cotton producers in Zone 3, Areas 1 and 2 (excluding Matagorda County) and the state's economy.

The emergency amendment to §20.22(a) changes the date for cotton stalk destruction for Zone 3, Area 1 (excluding Matagorda County), extending the deadline through October 15 and for Zone 3, Area 2, extending the deadline through October 29.

The amendment is adopted on an emergency basis under the Texas Agriculture Code, §74.006, which provides the Texas Department of Agriculture with the authority to adopt rules as necessary for the effective enforcement and administration of Chapter 74, Subchapter A; §74.004, which provides the department with the authority to establish regulated areas, dates and appropriate methods of destruction of stalks, other parts, and products of host plants for cotton pests and provides the department with the authority to consider a request for a cotton destruction extension due to adverse weather conditions; and the Government Code, §2001.34, which provides for the adoption of administrative rules on an emergency basis, without notice and comment.

*§20.22. Stalk Destruction Requirements.*

(a) Deadlines and methods. All cotton plants in a pest management zone shall be destroyed, regardless of the method used, by the stalk destruction dates indicated for the zone. Destruction shall be accomplished by the methods described as follows:
Figure: 4 TAC §20.22 (a)

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

This agency hereby certifies that the emergency adoption 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 September 28, 2001.

TRD-200105885
Dolores Alvarado Hibbs
Deputy General Counsel
Texas Department of Agriculture
Effective Date: September 28, 2001
Expiration Date: November 7, 2001
For further information, please call: (512) 463-4075

♦ ♦ ♦

## TITLE 19. EDUCATION

## PART 7. STATE BOARD FOR EDUCATOR CERTIFICATION

### CHAPTER 230. PROFESSIONAL EDUCATOR PREPARATION AND CERTIFICATION
### SUBCHAPTER O. TEXAS EDUCATOR CERTIFICATES BASED ON CERTIFICATION

AND COLLEGE CREDENTIALS FROM OTHER STATES OR TERRITORIES OF THE UNITED STATES

**19 TAC §230.462**

The State Board for Educator Certification (Board or SBEC) amends the emergency amendment to §230.462(h), relating to requirements for Texas certificates based on certification from other states or territories of the United States. The original emergency filing was published in the August 24, 2001, issue of the *Texas Register* (26 TexReg 6191). An emergency amendment to §245.5 was also published in the August 24, 2001, issue of the *Texas Register* (26 TexReg 6192).

The amendment to §230.462(h) is necessary to remove the phrase "from the effective date" in the first sentence. This phrase was erroneously published. Subsection (h) should now read as follows: "Upon request of an employing superintendent, the validity of an initial one year certificate with an effective date during the 2000-2001 school year may be extended for one consecutive calendar year. An initial one-year certificate with an effective date during the 2001-2002 school year shall be valid for two consecutive calendar years from the effective date. This subsection expires in accordance with Government Code §2001.034, relating to emergency rulemaking.

The amended section is adopted on an emergency basis pursuant to § 2001.034 of the Government Code, which allows a state agency to adopt an emergency rule if a requirement of state or federal law requires adoption of the rule on less than 30 days notice. Adoption of the amended sections will allow SBEC to prepare to implement House Bill 1721, which was passed by the 77th Legislature, 2001, (the "Act").

The amended sections allow initial one-year certificates with effective dates during the 2000-2001 and 2001-2002 school years to be extended for another calendar year from the effective date. The one-year certificate is the temporary credential issued to educators certified outside Texas who are now seeking Texas certification. This temporary credential allows these educators to be employed in the state's public schools while they are attempting the certification exams required by SBEC. Before the Act amended the Education Code, all educators from other states or countries had to pass the appropriate SBEC certification exams to be certified in Texas. (SBEC's testing program is called the Examination for the Certification of Educators in Texas or ExCET.)

Some of these educators certified by other jurisdictions may benefit from the provisions of the Act, which became effective June 16, 2001. The Act allows educators from other states or countries to obtain standard Texas certification without testing if their certifying jurisdiction required passage of certification exams "similar to and as rigorous as" SBEC's tests. To determine which educators qualify for a test exemption under the Act, SBEC must compare the certification exams given by other jurisdictions with the appropriate ExCET tests.

This emergency adoption is necessary because SBEC will need time to conduct a comparability study of other jurisdictions' certification exams. Adoption of the amended sections on an emergency basis allows SBEC time to take action to implement the new law according to legislative intent, while not unfairly denying continued employment in Texas public schools to out-of-state educators who may qualify for a test exemption.

Out-of-state educators issued initial one-year certificates with effective dates during the 2000-2001 or 2001-2002 school year may qualify for the exemption, depending on the results of the comparability study. Many of the one-year certificates issued during the 2000-2001 school year will expire before SBEC can propose and adopt amendments extending the term of one-year certificates under the usual rulemaking process. Similarly, many one-year certificates will be issued during the 2001-2002 school year before permanent rules can be approved.

Extending the term of these one-year certificates will allow the holders to maintain employment in the public schools while awaiting the results of the comparability study. The extended term will also allow these candidates a fair opportunity to attempt the appropriate certification exams if they do not wish to await or to risk the outcome of the comparability study.

Accordingly, the agency has determined that the Act requires the adoption of these amended sections on fewer than 30 days notice. Because SBEC is adopting the rules immediately without first proposing them, the provisions of the Education Code §21.042, relating to approval of proposed rules by the State Board of Education, do not apply.

The amended section is adopted on an emergency basis under the Education Code §21.031(a), which authorizes SBEC to regulate and to oversee all aspects of the certification of public school educators. As described above, the amended sections are also adopted under House Bill 1721 (77th Legislature, 2001) (to be codified at Education Code §21.052(a)(3)(B)) and under Government Code §2001.034.

There are no other codes affected.

*§230.462. Requirements for Texas Certificates Based on Certification from Other States or Territories of the United States.*

(a) An applicant for a Texas certificate based on a certificate issued in accordance with §230.461 of this title (relating to General Provisions) must pass the appropriate examination requirements specified in §230.5 of this title (relating to Educator Assessment).

(b) If all certification requirements are met except the appropriate examination requirements, the applicant may request issuance of a one-year certificate in one or more certification areas authorized on the out-of-state certificate.

(1) An applicant who holds a special subject certificate issued in accordance with §230.461 of this title (relating to General Provisions) may be issued the equivalent Texas certificate in that special subject area.

(2) An applicant who holds a professional service certificate issued in accordance with §230.461 of this subchapter may be issued the equivalent Texas certificate in that professional service area. The applicant must verify three creditable years of public or private school experience, as defined in Subchapter Y of this chapter (relating to Definitions), in the professional service area.

(c) After satisfying all requirements, including the examination requirements, the applicant is eligible to receive the Standard Certificate issued under Chapter 232, Subchapter M of this title (relating to the Types and Classes of Certificates Issued).

(d) An applicant issued a one-year certificate under this section who does not complete the appropriate examination requirements to establish eligibility for a Standard Certificate during the validity of the one-year certificate, is not eligible for any type of certificate or permit authorizing employment for the same certified level or areas until he or she has satisfied the appropriate examination requirements.

(e) An employing superintendent may apply for a nonrenewable permit for a teacher who does not pass the professional development portion of the Examination for the Certification of Educators in Texas (ExCET) but does pass the appropriate content specialization portions of the exam during the validity of the one-year certificate. The nonrenewable permit shall be valid for no more than 12 months from the date the individual first attempts the professional development portion of the ExCET.

(f) An applicant shall not be required to complete the content specialization portion of the ExCET in a certification area for which he or she does not seek standard certification.

(g) An applicant issued a one-year certificate under this section who, during or subsequent to the validity of the certificate, establishes eligibility for a Standard Certificate may apply for:

(1) a new one-year certificate in another certification area based on an acceptable certificate from another state or territory of the United States; or

(2) a second one-year certificate in an area previously authorized on a one-year certificate, provided the applicant was not assigned to the area and has not attempted the appropriate examination requirements for that area.

(h) Upon request of an employing superintendent, the validity of an initial one-year certificate with an effective date during the 2000-2001 school year may be extended for one consecutive calendar year. An initial one-year certificate with an effective date during the 2001-2002 school year shall be valid for two consecutive calendar years from the effective date. This subsection expires in accordance with Government Code §2001.034, relating to emergency rulemaking.

This agency hereby certifies that the emergency adoption 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 September 27, 2001.

TRD-200105865
Dan Junell
Interim Executive Director
State Board for Educator Certification
Effective Date: September 27, 2001
Expiration Date: December 7, 2001
For further information, please call: (512) 469-3011

♦ ♦ ♦

# TITLE 34. PUBLIC FINANCE

## PART 3. TEACHER RETIREMENT SYSTEM OF TEXAS

### CHAPTER 25. MEMBERSHIP CREDIT

### SUBCHAPTER L. OTHER SPECIAL SERVICE CREDIT

#### 34 TAC §25.162

The Teacher Retirement System of Texas adopts on an emergency basis amendments to §25.162 concerning the purchase of one year of service credit for accumulated state personal or sick leave. The rule implements Government Code §823.403 as amended by the 74th Legislature, 1995. The emergency amendments are being simultaneously proposed for permanent adoption in the proposed section of this issue of the *Texas Register*.

The emergency amendments delete language relating to state and federal restrictions that apply to permissive service credit purchases such as the requirement that a member be employed in a TRS covered position at the date of purchase of the credit. The emergency amendments also delete reference to Government Code §823.006 relating to the permissive service credit purchase restrictions associated with the purchase of nonqualified service under Government Code, §823.006 as it is not applicable. In addition, new language has been added to clarify that federal plan qualification requirements and limits under the Internal Revenue Code do apply.

The amendments are adopted on an emergency basis to enable the retirement system to process any person who wishes to purchase eligible service credit in accordance with applicable law. The agency finds that requirements of state law (specifically those found in Government Code §823.403 as amended by the 74th Legislature) require the adoption of these amendments on fewer than 30 days notice.

The amendments are adopted on an emergency basis under the Government Code, Chapter 825, §825.102, which authorizes the Board of Trustees of the Teacher Retirement System to adopt rules for eligibility for membership and the administration of the funds of the retirement system. The amendments are also adopted on an emergency basis under Government Code, Chapter 823, §823.404(b), which requires the Board of Trustees to adopt the rules regarding an employer's certification of a member's accumulated personal or sick leave and under §823.403(d) which authorizes the Board of Trustees to adopt rates and tables recommended by the actuary. In addition, Government Code, Chapter 825, §825.506, authorizes the Board to adopt rules necessary for the retirement system to be a qualified plan.

*§25.162. State Personal or Sick Leave Credit.*

(a) Effective September 1, 2001, an eligible member may purchase one year of service credit in the Teacher Retirement System of Texas ("TRS")for accumulated state personal or sick leave in accordance with Government Code §823.403 and subject to approval of TRS and to any [~~applicable restrictions including~~] plan qualification requirements and limits under the Internal Revenue Code of 1986, as amended from time to time[~~such as permissive service credit purchase restrictions. Permissive service credit purchase restrictions may limit the purchase of non-qualified service as defined in Government Code §823.006 to an aggregate of five years~~].

(b) A member is eligible to purchase one year of service credit if the member retires from an employer defined by §821.001(7) of the Government Code[~~, is employed by such an employer at the date of purchase of the service credit,~~] and has at least 50 days or 400 hours of accumulated state personal or sick leave on the last day of employment before retirement. Not more than an aggregate of five days of unused state personal or sick leave may be accumulated per year. State personal and sick leave may be combined, if needed, for the purpose of calculating the necessary 50 days or 400 hours. No more than one year of service credit may be purchased even if more time has been accumulated.

(c) Credit purchased under this section may be used only for the purpose of calculating benefits and may not be used to determine eligibility for benefits or for retirement, including eligibility for Texas Public School Employees Group Insurance Program per Article 3.50-4, §2(10)(A) of the Insurance Code.

(d) To establish service credit under this section, an eligible member must submit an employer certification in the form and manner prescribed by TRS. Additionally, the eligible member must deposit with TRS, in the manner prescribed by TRS, the actuarial present value of the additional standard retirement annuity benefits that would be attributable to the conversion of the unused state personal or sick leave into the service credit, as described in subsection (e) of this section.

(e) To compute these amounts, TRS will use the State Personal or Sick Leave Conversion Factor Tables furnished by the TRS actuary of record Specifically, TRS will select the applicable conversion factor from the table based on the age of the member in full years and months at the effective date of retirement. To obtain the cost of the service credit, the conversion factor will be multiplied by the increase in the monthly standard retirement annuity resulting from the conversion of state personal or sick leave to an additional one year of service credit. The increase in the annuity will be determined using the standard retirement annuity without an adjustment for an optional service retirement annuity plan selected by the member because any optional plan selected by the member is required by §824.204(b) of the Government Code to be the actuarial equivalent of the member's standard retirement annuity.

Figure 1: 34 TAC §25.162(e) (No change.)
Figure 2: 34 TAC §25.162(e) (No change.)
Figure 3: 34 TAC §25.162(e). (No change.)

This agency hereby certifies that the emergency adoption 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 October 1, 2001.

TRD-200105940
Charles L. Dunlap
Executive Director
Teacher Retirement System of Texas
Effective Date: October 1, 2001
Expiration Date: January 29, 2002
For further information, please call: (512) 391-2115

♦ ♦ ♦

# 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 1. ADMINISTRATION

## PART 1. OFFICE OF THE GOVERNOR

### CHAPTER 3. CRIMINAL JUSTICE DIVISION

The Office of the Governor proposes amendments to Title 1, Part 1, Chapter 3, Subchapter A, §3.9; Subchapter C, §3.803; and Subchapter E, §3.2519. The revisions clarify existing provisions and add new fund-specific requirements.

The proposed amendments provide processes and procedures relating to grants made through the Criminal Justice Division and include, but are not limited to, grant funding decisions, project requirements, and grant termination. Subchapter A concerns General Grant Program Provisions, Subchapter C concerns Fund-Specific Grant Policies, and Subchapter E concerns Administering Grants.

The Office of the Governor reviewed the rules affecting the Criminal Justice Division grant processes and procedures with the goal of increasing efficiency and updating the rules to address changes in the administration process. The review disclosed that a number of the rules required further clarification and simplification. As a result, the Office of the Governor has determined that the sections in the Texas Administrative Code identified above should be amended.

Tom Jones, Director of Accounting for the Criminal Justice Division, has determined that for the first five-year period the sections are in effect there will be no fiscal implications for state or local government as a result of enforcing or administering the sections.

Mr. Jones also has determined that for the first five-year period that the sections are in effect the public benefit anticipated as a result of enforcing the sections will be more efficient processes and procedures and the current rules will be more easily understood. There will be no anticipated economic cost to persons or small businesses for complying with the sections. There will be no anticipated economic costs to persons who are required to comply with the proposed amendments.

Comments on the proposed amendments may be submitted to Heather Morgan at the Criminal Justice Division of the Governor's Office, P.O. Box 12428, Austin, Texas 78711, (512) 463-1919.

### SUBCHAPTER A. GENERAL GRANT PROGRAM PROVISIONS

**1 TAC §3.9**

The amendments are proposed under the Texas Government Code, Title 7, §772.006(a)(11), which provides the Office of the Governor, Criminal Justice Division, the authority to adopt rules and procedures as necessary.

The amended rules implement the Texas Government Code, Title 7, §772.066(a), which requires the Office of the Governor, Criminal Justice Division, to advise and assist the governor in developing policies, plans, programs, and proposed legislation for improving the coordination, administration, and effectiveness of the criminal justice system.

*§3.9. Grant Funding Decisions.*

(a) All decisions to fund grant requests rest completely within the discretionary authority of CJD. The receipt of an application for grant funding by CJD does not obligate CJD to fund the grant or to fund it at the amount requested. CJD will separately review and approve or reject each aspect of an applicant's proposed project and the accompanying budget.

(b) CJD renders funding decisions based upon a review of whether the applicant is eligible, whether the proposed project meets the particular program requirements, and whether the request is reasonable. CJD renders decisions on applications for funding through the use of objective tools and comparative analysis.[~~Applicants may appeal adverse decisions on their applications for funding to CJD pursuant to §3.13 and §3.15 of this chapter.~~]

(c) If CJD decides not to fund a grant application or determines that an applicant is ineligible, CJD will notify the applicant in writing at least 30 days prior to the start date of the funding source.

(d) CJD makes no commitment that a grant, once funded, will receive priority consideration for subsequent funding.

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 October 1, 2001.

TRD-200105910
David Zimmerman
Assistant General Counsel
Office of the Governor
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 463-1919

♦ ♦ ♦

## SUBCHAPTER C. FUND-SPECIFIC GRANT POLICIES

## DIVISION 8. LOCAL LAW ENFORCEMENT BLOCK GRANT PROGRAM

### 1 TAC §3.803

The amendment of these rules are proposed under the Texas Government Code, Title 7, §772.006 (a) (11), which provides the Office of the Governor, Criminal Justice Division, the authority to adopt rules and procedures as necessary.

The amended rules implement the Texas Government Code, Title 7, §772.066(a), which requires the Office of the Governor, Criminal Justice Division, to advise and assist the governor in developing policies, plans, programs, and proposed legislation for improving the coordination, administration, and effectiveness of the criminal justice system.

No other statutes, articles or codes are affected by these amendments.

*§3.803. Project Requirements.*

(a) All projects funded through this program must have a regional or statewide impact and must meet at least one of the following purpose areas:

(1) Law enforcement support for:

(A) Hiring, training, and employing on a continuing basis, additional law enforcement officers and necessary support personnel. For the purposes of this program, a law enforcement officer may be police, corrections, probation, parole, or judicial officers.

(B) Paying overtime to currently employed law enforcement officers and necessary support personnel for the purpose of increasing the number of hours worked by such personnel.

(C) Procuring equipment, technology, and other material directly related to basic law enforcement functions.

(2) Enhancing security measures in and around schools, and in and around any other facility or location that the grant recipient considers a special risk for incidents of crime.

(3) Establishing or supporting drug courts. To be eligible for funding, a drug court program must include the following:

(A) Continuing judicial supervision over offenders who are substance abusers, but not violent offenders.

(B) Integrating administration of other sanctions and services which shall include:

*(i)* mandatory periodic testing of each participant for the use of controlled substances or other addictive substances during any period of supervised release or probation;

*(ii)* substance abuse treatment for each participant;

*(iii)* probation or other supervised release that involves the possible prosecution, confinement, or incarceration because of noncompliance with program requirements or failure to show satisfactory progress; and

*(iv)* programmatic offender management and aftercare services such as relapse prevention, vocational job training, and job and housing placement.

(4) Enhancing the adjudication of cases involving violent offenders, including cases which involve violent juvenile offenders. For the purposes of this program, violent offender indicates a person charged with committing a Part I violent crime (murder, rape, robbery, and aggravated assault) as defined under the Uniform Crime Report (UCR) Program.

(5) Establishing multi-jurisdictional task forces. The task force should concentrate on rural areas and be composed of law enforcement officials who represent units of local government. The task force will work with federal law enforcement officials to prevent and control crime.

(6) Establishing crime prevention programs involving cooperation between community residents and law enforcement personnel to control, detect, or investigate crime or the prosecution of criminals.

(7) Defraying the cost of indemnification insurance for law enforcement officers by supplying insurance for law enforcement officers to cover damage from willful acts to offenders by officers who are lawfully carrying out their duties.

(b) Prohibited uses. Grantees may not use grant funds to purchase, lease, rent, or acquire any of the following:

(1) tanks or armored vehicles;

(2) fixed-wing aircraft;

(3) limousines;

(4) real estate;

(5) yachts;

(6) consultants;

(7) vehicles not primarily used for law enforcement; and

(8) New construction. However, renovations of facilities are permitted when specifically approved by Bureau of Justice Assistance and the Office of the Comptroller. These costs may not exceed 10% of the total federal funds utilized in a given purpose area.

[~~(1) law enforcement support for procuring equipment, technology, and other material directly related to basic law enforcement functions; or~~]

[~~(2) Establishing a multi-jurisdictional task force (particularly in rural areas) composed of law enforcement officials who represent cities or counties. The task forces must work with federal, state, and local law enforcement officials to prevent and control crime.~~]

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 October 1, 2001.

TRD-200105911
David Zimmerman
Assistant General Counsel
Office of the Governor
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 463-1919

♦ ♦ ♦

## SUBCHAPTER E. ADMINISTERING GRANTS

### 1 TAC §3.2519

The amendment of these rules are proposed under the Texas Government Code, Title 7, §772.006 (a) (11), which provides the Office of the Governor, Criminal Justice Division, the authority to adopt rules and procedures as necessary.

The amended rules implement the Texas Government Code, Title 7, §772.066(a), which requires the Office of the Governor, Criminal Justice Division, to advise and assist the governor in developing policies, plans, programs, and proposed legislation for improving the coordination, administration, and effectiveness of the criminal justice system.

No other statutes, articles or codes are affected by these amendments.

*§3.2519. Grant Termination.*

(a) If a grantee wishes to cancel any approved project, it must notify CJD in writing immediately.

(b) CJD may terminate any grant, in whole or in part, when:

(1) a grantee fails to comply with any term or condition of the grant or the grantee has failed to comply with any applicable rule;

(2) the grantee and CJD agree to do so;

(3) grant funds are no longer available;

(4) conditions exist that make it unlikely that grant or project objectives will be accomplished; or

(5) the grantee has acted in bad faith.

(c) In the event that a grant is terminated by CJD, CJD will notify the grantee in writing of its decision.

[~~(d) Grantees may appeal the termination of a grant in accordance with §3.15.~~]

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 October 1, 2001.

TRD-200105913
David Zimmerman
Assistant General Counsel
Office of the Governor
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 463-1919

♦ ♦ ♦

# PART 4. OFFICE OF THE SECRETARY OF STATE

## CHAPTER 71. GENERAL POLICIES AND PROCEDURES

## SUBCHAPTER B. SERVICE OF PROCESS

### 1 TAC §71.21

The Office of the Secretary of State proposes an amendment to §71.21, concerning service of process on the Secretary of State. The purpose of the amendment is to correct the statutory cite pertaining to the fees that the Office of the Secretary of State must charge for performing service of process duties.

Guy Joyner, Chief, Legal Support Unit, Statutory Documents Section has determined that for the first five year period that the proposed amendments are in effect there will be no fiscal implications for state or local governments as a result of enforcing the amendment. There is no effect on large businesses, small businesses or micro-businesses. There is no anticipated additional economic cost to individuals who are required to comply with the amendment as proposed. There is no anticipated impact on local employment.

Mr. Joyner also has determined that for each year of the first five years that the amendment is in effect the public benefit anticipated as a result of enforcing the amendment will be the clarification of the statutory basis for the fees charged persons requesting service of process by the Office of the Secretary of State.

Comments on the proposed amendment may be submitted to Guy Joyner, Chief, Legal Support Unit, Statutory Documents Section, P.O. Box 12887, Austin, Texas 78711-2887.

The amendment is proposed under the Texas Government Code, §2001.004 (1) which provides the Secretary of State with the authority to prescribe and adopt rules.

The amendment does not affect any other statutes or Codes.

*§71.21. Service of Process.*

(a) Service on the Secretary. Service of process on the Secretary of State may be accomplished under many of the existing statutory authorities by delivering to the Secretary of State or to any clerk so designated by the secretary of state, two copies of the process. The name and appropriate address of the person or corporation being named as defendant must be provided. It is the responsibility of the attorney or person seeking service of process to determine when to obtain and to secure personal service of process upon the Secretary of State.

(b) Forwarding by the Secretary. One copy of the petition and citation will be forwarded by registered or certified mail, as appropriate under the particular statute under which service is being made, to the person or corporation named at the address provided.

(c) Certificate of Service. Upon request, the Secretary of State will issue a certificate showing:

(1) That service was accomplished;

(2) That a copy of the process was forwarded to the named defendant at the specified address; and

(3) The disposition of the mailing shown on the postal return receipt.

(d) Fees. The fees [~~fee~~] due the Secretary of State for maintaining a record of service of process, forwarding the process, [~~upon the Secretary of State~~] and for issuing a certificate of service shall be as provided in §405.031 of the Texas Government Code [~~the Texas Business Corporation Act, Article 10.01. The fee for issuing a certificate of service shall be as provided in Texas Government Code Annotated §405.031~~].

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 September 28, 2001.

TRD-200105880
Geoffrey S. Connor
Assistant Secretary of State
Office of the Secretary of State
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 475-0775

♦ ♦ ♦

# PART 17. TEXAS OFFICE OF STATE-FEDERAL RELATIONS

## CHAPTER 451. FEDERAL GRANT ASSISTANCE

## SUBCHAPTER A. THE STATE MATCH POOL FOR FEDERAL DISCRETIONARY GRANT ASSISTANCE

### 1 TAC §§451.1 - 451.9

*(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Office of State-Federal Relations or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)*

The Texas Office of State-Federal Relations proposes to repeal Title 1, Part 17, Chapter 451, Subchapter A, §§451.1 - 451.9, concerning Federal Grant Assistance.

The Legislature discontinued funding for the State Match Pool for Federal Discretionary Grant Assistance in 1995, and the authority to enforce these rules no longer exists.

Ed Perez, Acting Executive Director, has determined that for the first five-year period the repeal is in effect there will be no fiscal implications for state or local government as a result of the repeal.

Mr. Perez has also determined that for each year of the first five years the repeal is in effect the public benefit of the repeal will be that it will delete obsolete rules that the agency no longer has the authority to enforce. There will not be an effect on small, large, or micro businesses. There is no anticipated economic cost to persons who are required to comply with the proposed repeal.

Comments on the proposed repeal may be submitted in writing to Jon Hinojosa, Legislative Liaison, P.O. Box 13005, Austin, Texas 78711. Comments may also be submitted electronically to *statefed@governor.state.tx.us*. All comments must be received on or before 5:00 p.m., on November 12, 2001.

The statutory authority under Texas Government Code §751.022(b)(8) no longer exists.

No other codes, statutes, or articles are affected by the proposed repeal.

*§451.1. Introduction to and Purpose of the State Match Pool.*
*§451.2. Program Coverage.*
*§451.3. Eligibility for Funds.*
*§451.4. Maximum and Minimum Awards.*
*§451.5. Application for State Match Pool Funds.*
*§451.6. Review of Applications.*
*§451.7. Availability of Funds.*
*§451.8. Award Process.*
*§451.9. Awardee Responsibilities.*

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 September 27, 2001.

TRD-200105866
Ed Perez
Acting Executive Director
Texas Office of State-Federal Relations
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 463-1803

♦ ♦ ♦

# TITLE 13. CULTURAL RESOURCES

# PART 1. TEXAS STATE LIBRARY AND ARCHIVES COMMISSION

## CHAPTER 8. TEXSHARE LIBRARY CONSORTIUM

### 13 TAC §§8.1 - 8.6

The Texas State Library and Archives Commission proposes to amend §§8.1 - 8.6 regarding establishment and operation of the TexShare library consortium. These proposed revisions bring the TexShare rules in alignment with House Bill 1433, which was enacted by the 76th Legislature and House Bill 3591, which was enacted by the 77th Legislature.

Beverley Shirley, Library Resource Sharing Division Director, has determined that for the first five years the section is in effect there will be no fiscal implications for state or local government as a result of enforcing or administering the new rule.

Ms. Shirley also has determined that for each of the first five years the section is in effect the public benefits anticipated as a result of enforcing the section will be to clarify rules pertaining to the TexShare library consortium, and to protect the interests of the state as required under law. There are no cost implications to either small businesses or persons required to comply with the new rule.

Comments on the amendments may be submitted to Beverley Shirley, Director, Library Resource Sharing Division, Texas State Library and Archives Commission, P.O. Box 12927, Austin, Texas 78711-2927.

The amendments are proposed under Government Code §441.205(b) as amended by House Bill 2721, Acts, 75 Legislature, R.S. (1997) which authorize the commission to adopt rules to govern the operation of the consortium.

The amendments affect Government Code, §441.201 through §441.210.

*§8.1. Definitions.*

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

(1) Institution of higher education -- An institution of higher education as defined by Education Code, §61.003, and a private or independent institution of higher education as defined by Education Code, §61.003.

(2) Annual Report -- A report submitted to the Commission each year on the member institution of higher education's participation in TexShare programs, the member library of clinical medicine's participation in TexShare programs, or in fulfillment of a public library's system membership requirements. [~~Annual Report -- The annual submission of financial and library statistics to the Texas State Library and Archives Commission for inclusion in the publication "Texas Academic Library Statistics."~~]

(3) Commission -- The Texas State Library and Archives Commission.

(4) Consortium -- The TexShare Library Consortium.

(5) Director and Librarian -- Chief executive and administrative officer of the commission.

(6) Public Library has the meaning assigned by Government Code, §441.122

(7) Library of clinical medicine has the meaning assigned to Non-Profit Corporation by Government Code, §441.221.

(A) Extensive library services are defined as those services set forth in § 1.81, Subsection 4(c)(d) of this title.

(B) Extensive collections in the fields of clinical medicine and the history of medicine-a minimum of 10,000 library resources in print and in electronic format, comprised of books, journal titles, technical reports, and databases on clinical medicine and the history of medicine.

(8) [~~(6)~~] Internet connection -- A combination of hardware, software and telecommunications services that allows a computer to communicate with any other computer on the worldwide network of networks known as the Internet, and that adheres to Internet standards documents of the Internet Engineering Steering Group, Internet Architecture Board, and the Internet community. [~~the standard protocols listed in RFC 1920 or its current successor document.~~]

[~~(7) Request for Comments (RFC)--A version of an Internet specification, published as part of the "Request for Comments" (RFC) document series, the official publication channel for Internet standards documents and other publications of the Internet Engineering Steering Group, Internet Architecture Board, and Internet community.~~]

*§8.2. Purpose.*

The purpose of TexShare is to assist public libraries, libraries of clinical medicine, and libraries at institutions of higher education in Texas:

(1) to improve the availability of library resources in all communities;

(2) [~~(1)~~] to promote the future health and well-being of the citizenry and enhance quality teaching and research excellence at institutions of higher education through the efficient exchange of [~~academic~~] information and the sharing of library resources;

(3) [~~(2)~~]to maximize the effectiveness of library expenditures by enabling libraries [~~at institutions of higher education~~] to share staff expertise and to share library resources in print and in an electronic form, including books, journals, technical reports, and databases;

(4) [~~(3)~~] to increase the intellectual productivity of customers [~~students and faculty~~] at the participating institutions [~~of higher education~~] by emphasizing access to information rather than ownership of documents and other information sources; and

(5) [~~(4)~~] to facilitate joint purchasing agreements for purchasing information services and encourage cooperative research and development of information technologies.

*§8.3. Membership.*

(a) Eligibility. Membership in the consortium is open to all institutions of higher education as determined by the Texas Higher Education Coordinating Board, to libraries of clinical medicine, and to all public libraries that are members of the state library system, as defined in Government Code, §441.127.

(b) Agreement. Public libraries will be TexShare Members so long as they remain members of the state library system. Institutions of higher education and libraries of clinical medicine must file a membership agreement, signed by a duly authorized administrative official, [~~the president or chancellor,~~] on joining the consortium. Participation in specific programs of the consortium may require additional agreements and fees.

(c) Annual Report. Libraries of member institutions of higher education and member libraries of clinical medicine shall file a current and complete annual report for the preceding year with the commission by January 15 of each year. Public libraries shall file their state library system reports as required by §1.85 of this title.[~~Failure to file a report by January 15 may result in suspension of membership for the next state fiscal year. Revisions to the annual report which would affect membership status for the next state fiscal year will not be accepted after February 15. Willful falsification of annual reports shall cause the library to be disqualified for one year in the first instance and disqualified for three years in the second instance.~~]

(d) Multiple Libraries. For institutions of higher education, the unit of membership in the TexShare Library Consortium shall be the institution. Community college districts may apply as a single unit or as individual campuses; other institutions of higher education with [~~campus~~]libraries in multiple locations [~~in one county~~] shall apply as a single unit. Public libraries with branches shall apply as a single unit. Libraries affiliated with professional schools that demonstrate they are administered and budgeted independently of the campus library may apply for separate membership. For libraries of clinical medicine, the unit of membership shall be the non-profit corporation; those having multiple locations shall apply as a single unit.

(e) Suspension of membership.

(1) Institutions of higher education and libraries of clinical medicine: Membership will be automatically renewed for each state fiscal year, provided that the library of clinical medicine or institution of higher education continues to meet the definition required in subsection (a) of this section; and an annual report has been filed as required by subsection (c) of this section. [~~and that the institution remains qualified for programs of the Texas Higher Education Coordinating Board. Institutions which have lost accreditation or are otherwise not qualified on the first day of any state fiscal year will be suspended from membership until the first day of the succeeding state fiscal year.~~]

(2) Public libraries: Public libraries shall remain TexShare members so long as they remain members of the state library system.

(3) Institutions of higher education, libraries of clinical medicine, and public libraries that no longer meet the definition in

subsection (a) of this section, or are otherwise not qualified, will be suspended from membership. They may re-join TexShare when they meet the definition in subsection (a) of this section.

(f) Tiers. Institutions of higher education [~~Member institutions~~] are placed in one of three tiers on the basis of the size of their book collection and student enrollment, as reflected in the latest statistics from the National Center for Educational Statistics, the Texas Higher Education Coordinating Board, and the Independent Colleges and Universities of Texas. [~~annual report filed with the commission.~~]

(1) Tier 1: Over 750,000 volumes or over 10,000 enrollment.

(2) Tier 2: 100,000-749,999 volumes or 2,001-9,999 enrollment.

(3) Tier 3: Under 100,000 volumes and 2,000 or less enrollment.

(g) Fees. Some consortium services are supported by fees paid by participants. Fees will be set by the Director and Librarian for different categories of consortium services. [~~on the basis of costs for the individual programs and/or the tier placement of the institutions.~~]

*§8.4. Advisory Board.*

(a) The commission shall appoint an eleven-member[~~a nine-member~~] advisory board to advise the commission on matters relating to the consortium. At least two members must be representatives of the general public [ ~~members~~], at least two members must be affiliated with a four-year public university in the consortium, at least two members must be affiliated with a public community college in the consortium, [ ~~and~~] at least two members must be affiliated with a private institution of higher education in the consortium and at least two members must be affiliated with a public library in the consortium. The eleventh [~~ninth~~] member is at large without any affiliation specified. Members of the advisory board must be qualified by training and experience to advise the commission on policy.

(b) Members of the advisory board shall be chosen to present as much variety as possible in geographic distribution and size and type of institution.

(c) The advisory board shall meet at least twice a year regarding consortium programs and plans at the call of the advisory board's chairman or of the director and librarian.

(d) Members of the advisory board serve three-year terms beginning September 1.

(e) A member of the advisory board serves without compensation but is entitled to reimbursement for actual and necessary expenses incurred in the performance of official duties, subject to any applicable limitation on reimbursement provided by the General Appropriations Act.

(f) The advisory board shall elect a chairman and a vice chairman, and secretary at the first meeting of each fiscal year.

(g) The advisory board may recommend to the commission that the consortium enter into cooperative projects with entities other than public libraries, libraries of clinical medicine, or institutions of higher education.

*§8.5. Programs.*

The programs of the consortium shall include activities designed to facilitate library resource sharing. Such activities may include:

(1) providing electronic networks, shared databases, reciprocal borrowing, delivery services, and other infrastructure necessary to enable the libraries in the consortium to share resources;

(2) negotiating and executing statewide contracts for information products and services;

(3) coordinating library planning, research and development; or

(4) training library personnel.

*§8.6. Grants: Access to Local Holdings.*

(a) Purpose. To provide seed money to assist libraries in Texas institutions of higher education , libraries of clinical medicine, and public libraries to provide access to their special or unique holdings and to make information about these holdings available to library users across the state.

(b) Eligibility. Libraries in institutions of higher education, libraries of clinical medicine and public libraries that have been certified as meeting the TexShare membership requirements in §8.3 of this title (relating to Membership) for the state fiscal year in which the grant is awarded are eligible to apply for local holdings grants. A member library may apply on behalf of a group of member libraries in a cooperative project, or for funding of the member library portion of a project including other libraries or organizations.

(c) Services to be Provided. This grant program focuses on making unique library collections accessible for TexShare constituents. Applicants may propose projects designed to increase accessibility through a wide range of activities such as organizing, cataloging, indexing, microfilming and digitizing local materials.

(d) Standards requirements. Cataloging or indexing information created under the grant must be available through the OCLC Incorporated bibliographic database or an Internet connection. Digitized materials must be available through an Internet connection, and be created, stored, and accessible in accordance with the Library of Congress National Digital Library Program as published in Digital Historical Collections: Types, Elements, and Construction, Digital Formats for Content Reproductions, and Access Aids and Interoperability, or their successor documents.

(e) General Selection Criteria.

(1) This grant program is competitive. Selection criteria are designed to select applications that provide the best overall value to the state.

(2) The award criteria include:

(A) program quality as determined by a peer review process; and

(B) the cost of proposed service.

(3) The commission may consider additional factors in determining best value, including:

(A) financial ability to perform services;

(B) state and regional service needs and priorities;

(C) ability to continue services after grant period; or

(D) past performance and compliance.

(f) Peer Review.

(1) The commission uses peer reviewers to evaluate the quality of applications in competitive grant programs.

(2) The director and librarian will select qualified individuals to serve as peer reviewers. Peer reviewers shall demonstrate appropriate training, or service on citizen boards in an oversight capacity, and shall not have a conflict of interest.

(3) The commission staff will provide written instructions and training for peer reviewers.

(4) The reviewers score each application according to criteria set by the commission.

(g) Award Criteria. Points for each criterion will be based primarily on the measures listed; raters may also consider other relevant factors in scoring each criterion. The measures and weights for the criteria are:

(1) Significance of the collection. Is the collection unique, or unique for a geographic region? Will the materials be useful to users [~~at institutions~~ ] throughout the state? <u>Does this project focus on materials about Texas?</u> Will the project provide an "advancement of knowledge" rather than cleaning up general backlogs? Maximum Points: 30.

(2) Availability. How will access to the collection be provided? Will bibliographic records be available through OCLC or the Internet? Will materials themselves be available through an Internet connection, through interlibrary loan, through reciprocal borrowing, or only on-site use? Maximum Points: 30.

(3) Project Design. Is the project well defined? Is it a discrete project which can be completed in the grant period? Maximum Points: 15.

(4) Cost Sharing. What is the level of local funding available to share in the project costs? Are matching funds currently available? Are the matching funds higher than the required minimum? Maximum Points: 5.

(5) Cost Effectiveness. How appropriate are the chosen hardware, software, staffing, and service providers for the project, given the cost of the project? Is the budget realistic? Does the project proposal make effective use of the grant funds? Maximum Points: 15.

(6) Evaluation. How well has the applicant designed and described the methodology to evaluate the project and estimate the level of usage? Is the evaluation methodology appropriate and effective? Maximum Points: 5.

(h) Eligible costs. Eligible costs are: Staff or contracted services costs for organizing, cataloging, indexing, or digital conversion of materials; charges for updating shared bibliographic database records; central processing units (CPUs) and associated peripherals, storage devices, telecommunications devices and software necessary to provide storage and access for digitized materials; supply costs necessary to provide storage and access; indirect and audit costs; travel necessary to organize materials directly associated with the grant.

(i) Matching requirement. Each applicant must expend an amount from local funds at least equal to 30% of the total budgeted project costs which are eligible grant costs. If the matching requirement is not met, as determined by audit, the institution will have to refund all or a portion of the grant. The match can be from a foundation grant; gifts from citizens, corporations or organizations; friends of the library donations; revenues from the sale of bonds or certificates of obligation; federal funds; locally appropriated funds; or a combination. State or federal funds awarded to the grantee from any other commission program may not be used as matching funds. Required matching funds must be available at the beginning of the grant period; applicants that have matching funds available, or committed, at the time of application will receive a higher funding priority.

(j) Prior expenditures. Expenditures by local applicants for consultant fees and preliminary planning costs of an approved project, made prior to the date of commission approval, are eligible as matching funds, but only if made within the year prior to the beginning of the grant term.

(k) Maximum award. The maximum grant award will be no more than 20% of the available funding in any given award period.

(l) Application and Review Process. A prospective applicant must submit an application to the commission on the forms and at the time specified by the commission.

(1) The commission staff will review applications to determine if all requested information has been provided in a timely fashion, on prescribed forms.

(A) An application must be complete with proper authorization to qualify for further consideration.

(B) Qualified applications will be forwarded to the peer reviewers for evaluation.

(C) The commission staff will notify applicants eliminated through the screening process within 30 days of the submission deadline.

(2) Peer Reviewers will evaluate applications and assign scores based on the award criteria.

(3) Commission staff will rank each application based on points assigned by peer reviewers, and recommend a priority ranked list of projects to the commission for approval.

(m) Funding Decisions.

(1) The commission will approve a priority ranked list of applicants for possible funding based upon recommendations of commission staff. Final approval of a grant award is solely at the determination of the commission.

(2) Applications for grant funding will be evaluated only upon the information provided in the written application.

(3) Funding recommendations to the commission will consist of the highest ranked applications up to the limit of available funds. If available funds are insufficient to fully fund a proposal after the higher-ranking proposals have been fully funded, staff will negotiate with the applicant to determine if a lesser amount would be acceptable. If the applicant does not agree to the lesser amount, the staff will negotiate with the next applicant on the ranked list. The process will be continued until all grant funds are awarded.

(4) In the unlikely event that two proposals receive identical scores and funds are insufficient for both, staff will recommend awarding funds to the applicant requesting the lesser amount of state funding. If any funds remain after an award is made to this applicant, staff will negotiate with the other applicant in question. If these negotiations are unsuccessful, staff will negotiate with the next applicant on the ranked list.

(n) Contract. Following approval of the grant awards by the commission, the staff will issue a contract to the successful applicants based on the information contained in the project application.

(o) Cancellation or Suspension of Grants. The commission has the right to reject all applications and cancel a grant solicitation at any point before a contract is signed.

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 October 1, 2001.

TRD-200105904
Edward Seidenberg
Assistant State Librarian
Texas State Library and Archives Commission
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 463-5459

♦ ♦ ♦

# TITLE 22. EXAMINING BOARDS

## PART 3. TEXAS BOARD OF CHIROPRACTIC EXAMINERS

## CHAPTER 71. APPLICATIONS AND APPLICANTS

### 22 TAC §71.9

The Texas Board of Chiropractic Examiners proposes to amend Chapter 71, relating to applications and applicants for a chiropractic license. The proposal creates a new §71.9, relating to applicants who fail to appear at a scheduled examination. The new section will allow an applicant who gives prior notice of the inability to take an examination or who provides the board with an acceptable excuse to re-take the examination without repaying another examination fee. Currently, an applicant is required to submit a non-refundable examination fee for the jurisprudence examination. If the applicant does not take the examination regardless of the reason, it has been the practice of the board to apply the fee to a subsequent application for examination. Under the proposed new §71.9, if an applicant simply fails to appear and has no acceptable excuse, the applicant will be required to submit another examination fee for taking the examination. In fiscal year 2001, there was an average of three applicants per exam who failed to appear for the scheduled exam, giving no advance notice to the board. Some applicants failed to appear on more than one occasion. The board hopes that the rule will significantly reduce the number of no shows at the jurisprudence examinations, by providing an incentive to show up or to give the board notice of non-appearance prior to the exam in order to avoid paying multiple examination fees.

Jessica Harwell, Director of Rules, has determined that for the first five-year period the proposed new rule is in effect, the fiscal impact will be less than $2000 in increased revenue for state government, as a result of enforcing or administering the rule as proposed. There is no anticipated fiscal impact on local government. The current rate of no excuse, no show is an average of three applicants per examination. Assuming that the proposed rule will reduce that rate to 1 per examination, the estimated increase in revenue will be $325 per examination. The board gives approximately 6 examinations per year, providing for an estimated additional yearly revenue of $1950.

Ms. Harwell has determined that for each year of the first five years, the section as proposed is in effect, the public benefit anticipated as a result of enforcing and administering the new section, will be better attendance by applicants or recovery of the cost of preparing an examination for a no-show. Since an applicant for examination is not eligible to practice until after examination and licensure, theoretically, there will be no effect on small or micro businesses, as defined by Government Code §2006.002. Moreover, as along as an applicant appears for examination, gives prior notice, or provides an acceptable excuse for not appearing, there will be no anticipated economic cost to persons who are required to comply with the section as proposed. Only if an applicant who plans on operating a small or micro business fails to take his or her responsibilities for showing up as promised will he or she be required to pay another examination fee.

Written comments may be submitted no later than 30 days from the date of this publication, to Jessica Harwell, Rules Committee, Texas Board of Chiropractic Examiners, 333 Guadalupe, Tower III, Suite 825, Austin, Texas 78701.

The new section is proposed under the Occupations Code §201.152, which the board interprets as authorizing it to adopt rules necessary for the performance of its duties, and specifically, for the examination of an applicant for a license to practice chiropractic.

The following are the statutes, articles, or codes affected by the new section:

§71.9--Occupations Code, §201.152.

*§71.9. Failure to Appear at Jurisprudence Examination.*

(a) If an applicant notifies the board no later than one day prior to the date of examination that he or she is unable to take the examination, the board will apply the examination fee to a subsequent application to take the examination.

(b) If an applicant fails to appear for a scheduled examination without prior notice to the board, the applicant must pay another examination fee when he or she applies for a subsequent examination unless the board excuses the non-appearance as provided in subsection (c) of this section.

(c) An applicant who fails to appear for examination without prior notice may be excused for illness, death in the immediate family, disabling traffic accident, court appearance, jury duty, or military duty, or other extenuating circumstances beyond the control of the applicant. The applicant must submit to the board a notarized affidavit setting out the reasons for not appearing, along with any supporting documents, no later than 14 days after the examination date. Documentation for medical absences must have the original signature of the medical practitioner. Stamped signatures will not be accepted.

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 October 1, 2001.

TRD-200105908
Gary K. Cain, Ed.D.
Executive Director
Texas Board of Chiropractic Examiners
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 305-6709

♦ ♦ ♦

## CHAPTER 80. MISCELLANEOUS

### 22 TAC §80.1

The Texas Board of Chiropractic Examiners proposes to amend §80.1(c)(5), relating to tasks and procedurals that may be delegated by a licensee. The proposal adds the words "procedures and activities" to paragraph (5), clarifying the types of tasks or procedures relating to physical therapy that may be delegated.

Dr. Serge François, D.C., Chair, Rules Committee, has determined that for the first five-year period the proposed amendment is in effect, there will be no fiscal implications for state government or local government as a result of enforcing or administering the rule as amended. There will be no effect on small or micro businesses, or anticipated economic cost to persons who are required to comply with the section as proposed.

Dr. François has determined that, for each year of the first five years, the section as amended is in effect, the public benefit anticipated as a result of enforcing and administering the section as amended will be better clarity of the types of tasks or procedures that a licensee may delegate under the section.

Written comments may be submitted no later than 30 days from the date of this publication, to Jessica Harwell, Rules Committee, Texas Board of Chiropractic Examiners, 333 Guadalupe, Tower III, Suite 825, Austin, Texas 78701.

The amendment is proposed under the Occupations Code §201.152, which the board interprets as authorizing it to adopt rules necessary for the performance of its duties, the regulation of the practice of chiropractic, and the enforcement of the Chiropractic Act.

The following are the statutes, articles, or codes affected by the amendments:

§80.1(c)(5)--Occupations Code, §201.152

*§80.1. Delegation of Authority.*

(a) - (b) (No change.)

(c) "Qualified and properly trained" as used in this subsection means that the person, in addition to the requisite training and skill, has any license or certification required by law in order to perform a specific task or procedure. A licensee may allow or direct a qualified and properly trained person, who is acting under the licensee's supervision, to perform a task or procedure that assists the chiropractor in making a diagnosis, prescribing a treatment plan or treating a patient if the performance of the task or procedure does not require the training of a chiropractor in order to protect the health or safety of a patient, such as:

(1) - (4) (No change.)

(5) performing prescribed physical therapy modalities, procedures and activities;

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

(d) (No change.)

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 October 1, 2001.

TRD-200105909
Gary K. Cain, Ed.D.
Executive Director
Texas Board of Chiropractic Examiners
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 305-6709

♦ ♦ ♦

# PART 23. TEXAS REAL ESTATE COMMISSION

## CHAPTER 535. PROVISIONS OF THE REAL ESTATE LICENSE ACT
## SUBCHAPTER T. EASEMENT OR RIGHT-OF-WAY AGENTS

**22 TAC §535.400**

The Texas Real Estate Commission (TREC) proposes an amendment to §535.400, concerning registration of easement or right-of-way agents. The amendment would eliminate the requirement that a person applying for registration as an easement or right-of-way agent online furnish TREC with a hard copy of the application within 60 days to complete the application. Rather, the person would be required to furnish TREC with a photograph and signature prior to receiving a registration, and the photograph and signature could be furnished before the application is filed. The amendment would streamline the electronic application process presently being developed by TREC, while obtaining appropriate identification of the applicant.

Mark A. Moseley, general counsel, has determined that for the first five-year period the section as proposed is in effect there will be no fiscal implications for the state or for units of local government as a result of enforcing or administering the section. There is no anticipated impact on small businesses, micro businesses or local or state employment as a result of implementing the section.

Mr. Moseley also has determined that for each year of the first five years the section as proposed is in effect the public benefit anticipated as a result of enforcing the section will be the elimination of possible delays in the registration process for easement or right-of-way agents. There is no anticipated economic cost to persons who are required to comply with the proposed section.

Comments on the proposal may be submitted to Mark A. Moseley, General Counsel, Texas Real Estate Commission, P.O. Box 12188, Austin, Texas 78711-2188.

The amendment is proposed under Texas Civil Statutes, Article 6573a, §5(h), which authorizes the Texas Real Estate Commission to make and enforce all rules and regulations necessary for the performance of its duties.

The statute which is affected by this proposal is Texas Civil Statutes, Article 6573a.

*§535.400. Registration of Easement or Right-of-Way Agents.*

(a) (No change.)

(b) An individual desiring to be registered by the commission as an easement or right-of-way agent must file form ERW 1-2 with the commission. If the applicant is a business, the applicant must file form ERW 2-2. All applicants must submit the applicable fees set forth in The Real Estate License Act, Texas Civil Statutes, Article 6573a, (the Act). The commission will not accept an application which has been submitted without the correct filing fees or which has been submitted in pencil. If the commission develops a system whereby a person may electronically file an application for registration, a person also may apply for registration by accessing the commission's Internet web site, entering the required information on the application form and paying the appropriate fee in accordance with the instructions provided at the site by the commission. If the person is an individual, the person must provide the commission with the person's photograph and signature prior to issuance of a registration certificate. The person may provide the photograph and signature prior to the submission of an electronic application. [~~Within 60 days after paying the fee, the applicant must complete the application process by submitting a printed copy of the application signed by the applicant and including a photograph of the applicant.~~] If the applicant does not complete the application process as required by this subsection, the commission shall terminate the application.

(c)-(f) (No change.)

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 September 25, 2001.

TRD-200105794
Mark A. Moseley
General Counsel
Texas Real Estate Commission
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 463-3900

♦ ♦ ♦

# PART 25. STRUCTURAL PEST CONTROL BOARD

## CHAPTER 591. GENERAL PROVISIONS

### 22 TAC §591.4

The Structural Pest Control Board proposes amendments to §591.4, concerning Board Office. The proposal deletes Austin as the designated city for the location of the Structural Pest Control Board office.

Dale Burnett, Executive Director has determined that there will not be fiscal implications as a result of enforcing or administering the rule.

There will be no estimated additional cost, estimated reduction in cost or estimated loss or increase in revenue to state or local government for the first five year period the rule will be in effect.

There will be no cost of compliance with the rule for small businesses.

There will be no cost per employee, cost per hour of labor or cost per $100 of sales for small or larger businesses.

Dale Burnett, Executive Director has determined that for each year of the first five years the rule as proposed is in effect, the public benefits anticipated as a result of enforcing the rule as proposed will be the Board fulfilling the 77th Legislative Session mandate that dictates the Board office be relocated outside the City of Austin with the idea that the move will save the State leasing costs, in turn the tax paying citizens of Texas.

There is no anticipated economic cost to individuals required to comply with the rule as proposed.

Comments on the proposal may be submitted to Frank M. Crull, General Counsel, Structural Pest Control Board, 1106 Clayton Lane #100LW, Austin, Texas 78723.

The amendment is proposed under Article 136b-6, Tex.Rev.Civ.Stat.Ann., which provides the Structural Pest Control Board with the authority to license and regulate the structural pest control industry.

No other statute, code or article is affected by the proposed amendment.

*§591.4. Board Office.*

The office of the Board will be located in [~~Austin,~~] Texas.

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 October 1, 2001.

TRD-200105888
Dale Burnett
Executive Director
Structural Pest Control Board
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 451-7200

♦ ♦ ♦

# TITLE 30. ENVIRONMENTAL QUALITY

# PART 1. TEXAS NATURAL RESOURCE CONSERVATION COMMISSION

## CHAPTER 60. COMPLIANCE HISTORY

### 30 TAC §60.1

The Texas Natural Resource Conservation Commission (commission) proposes new §60.1, Compliance History. The commission proposes new Chapter 60 to implement certain requirements of House Bill (HB) 2912, 77th Legislature, 2001, regarding compliance history.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE PROPOSED RULE

House Bill 2912, 77th Legislature, 2001, §4.01, amended Texas Water Code (TWC), Chapter 5, Texas Natural Resource Conservation Commission, by adding Subchapter Q, Performance-Based Regulation. New Subchapter Q of TWC, §5.753, Standard For Evaluating Compliance History, requires the commission to "develop a uniform standard for evaluating compliance history." The purpose of this proposed rule is to define the components of compliance history.

The commission currently has procedures for preparation of compliance summaries for permit applications for waste disposal activities conducted under the authority of TWC, Chapters 26 and 27, and the Texas Solid Waste Disposal Act, Texas Health and Safety Code (THSC), Chapter 361, and the Texas Radiation Control Act, THSC, Chapter 401, and these procedures are specified in existing 30 TAC §281.21(d). These current procedures specify that a compliance summary shall cover at least the two-year period preceding the date on which the technical review is completed and shall include: 1) the date(s) and descriptions of any citizen complaints received; 2) the date(s) of all agency inspections, and for each inspection, whether a condition of noncompliance was alleged by the inspector and a brief description of the resulting environmental impact; 3) the date(s) of any agency enforcement action and the applicant's response to such action; 4) the date(s) and description of any incident the applicant reported to the agency which required implementation of the facility contingency plan, if applicable; and 5) the name and telephone number of a person to contact for additional compliance history.

The commission currently has procedures for preparation of compliance summaries for permit applications for air emissions under the authority of the Texas Clean Air Act, THSC, Chapter 382, and these components are specified in existing 30 TAC §116.122. The associated procedures specify that a compliance summary shall cover five years and shall include the following compliance events and associated information involving the Texas facility that is the subject of the permit application: criminal convictions known to the commission and civil orders, judgments, and decrees; administrative enforcement orders; and compliance proceedings. For United States facilities outside the State of Texas, the compliance summary shall include criminal convictions and civil judgments, administrative enforcement orders, and notices of violation issued by the United States Environmental Protection Agency (EPA). Furthermore, §116.122 specifies that violations of fugitive emission monitoring and recordkeeping requirements meeting certain criteria shall not be included in the compliance history.

The commission is also required by TWC, §7.053 to consider compliance history (as one of several factors) for purposes of assessing administrative penalties in commission enforcement actions. As reflected in the commission's penalty policy (first revision, effective January 1, 1999), when assessing compliance history for enforcement purposes, a five-year history of the violator is examined in all programs of all media under the jurisdiction of the commission for the specific site under enforcement. Additionally, in evaluating the violator, the histories of all of its locations in the state are considered for the medium or media of concern in the enforcement action. For example, this includes multiple water or wastewater plants owned by a city; parent, sister, or daughter companies in a corporate entity; and companies owned by each partner in a partnership. Furthermore, if the site of the violation has undergone a change in ownership, both the five-year histories of the site itself and of the new owner are examined. The components of compliance history considered for enforcement purposes are previous commission or federal enforcement orders that include findings of fact and conclusions of law, district court orders, federal court orders, or criminal convictions related to environmental laws.

The commission currently uses compliance history as a criterion for participation in the voluntary Clean Texas Program. Any facility that has been issued a findings order by the commission three years prior to the application date is ineligible to participate. Any facility that has been the subject of a state or federal district court judgment for up to three years prior to the application is also ineligible to participate. Lastly, any facility with a criminal conviction or whose employees have a criminal conviction for infraction of environmental laws is ineligible to participate.

Proposed new Chapter 60 would implement the requirement of HB 2912, §4.01 to "develop a uniform standard for evaluating compliance history" by specifying the components to be considered in evaluating compliance history for permit decisions, as well as other specified types of authorizations, including licenses, certificates, registrations, approvals, permits by rule, standard permits, or other forms of authorization requiring agency approval. As specified in TWC, §5.751, the compliance history requirements of HB 2912 do not apply to occupational licensing programs under the jurisdiction of the commission. The commission proposes that this rule only applies to forms of authorization, including temporary authorizations, that require some level of notification to the agency, review, and approval or response. This rule would not apply to permit actions such as voluntary permit revocations; minor amendments and non-substantive corrections to permits; Texas pollutant discharge elimination system (TPDES) and underground injection control minor permit modifications; Class 1 solid waste modifications, except for changes in ownership; municipal solid waste Class I modifications, except for temporary authorizations and municipal solid waste Class I modifications requiring public notice; permit alterations; and administrative revisions, unless a motion for reconsideration or a motion to overturn is filed under 30 TAC §50.39 or §50.139 with respect to the listed permit actions. The bill further states that compliance history must be utilized in agency decisions regarding enforcement, the use of announced inspections, and participation in innovative programs. House Bill 2912 limits the use of compliance history to programs under the jurisdiction of the commission under TWC, Chapters 26 and 27, and THSC, Chapters 361, 382, and 401.

New Chapter 60 proposes a compliance period of at least five years. The period of time will be based on the five-year period preceding the date the permit application is received by the executive director; the five-year period preceding the date of the inspection that initiates an enforcement action; for purposes of determining whether an announced inspection is appropriate, the five-year period preceding an inspection; or the five-year period preceding the date the application for participation in an innovative program is received by the executive director, as applicable. According to HB 2912, §18.05, the agency must begin using the new components of compliance history for actions taken by the agency on or after February 1, 2002.

Additionally, §18.05 specifies that this proposed new chapter will apply in the consideration of compliance history for decisions by the agency relating to the issuance, amendment, modification, or renewal of permits under TWC, §§5.754, 26.028, 26.0281, 26.040, and 27.018, and THSC, §§361.084, 361.088, 361.089, 382.0518, 382.055, 382.056, 401.110, and 401.112, only to applications submitted on or after September 1, 2002; in the consideration of compliance history for actions taken by the agency relating to inspections and flexible permitting, effective September 1, 2002; and in the consideration of compliance history in decisions of the commission relating to the suspension or revocation of a permit or the imposition of a penalty in a matter under the jurisdiction of the commission, only to a proceeding that is initiated or an action that is brought on or after September 1, 2002. Use of compliance history for innovative programs (except flexible permits) and other forms of authorization will begin September 1, 2002. These applicability dates are specified in proposed new §60.1.

The components of compliance history specified in new Chapter 60 include enforcement orders; court judgments; consent decrees; criminal convictions of this state and the federal government relating to compliance with an environmental law, regulation, permit, order, consent decree, or other requirement under the jurisdiction of the commission or the EPA; orders issued under TWC, §7.070; to the extent readily available, enforcement orders, court judgments, and criminal convictions relating to violations of environmental laws of other states; chronic excessive emissions events; any information required by other law or any requirements necessary to maintain federal program authorization; dates of investigations; notices of violations; any notices of audits conducted under the Texas Environmental, Health, and Safety Audit Privilege Act, 74th Legislature, 1995; the type of environmental management systems used for environmental compliance; any voluntary on-site compliance assessments conducted by the executive director under a special assistance program; participation in a voluntary pollution reduction program; and the name and telephone number of an agency staff person to contact for additional information regarding compliance history. Additionally, compliance histories would now cover all media, including air, water, and waste. Changes in ownership would also be reflected.

Proposed §60.1 would only implement the first phase of HB 2912, §4.01, as it relates to the definition, or components of, compliance history. The next phase of the implementation of HB 2912, §4.01, relating to the use of compliance history, will be accomplished through additional rulemaking. House Bill 2912, §18.05(a), specifies that, not later than September 1, 2002, the commission by rule shall establish the standards for the classification and use of compliance history, as required by TWC, §5.754. This additional rulemaking will include modifications to Chapter 60, as well as to other applicable chapters of commission rules for the purpose of implementing the compliance history requirements of HB 2912, §4.01.

The commission solicits additional comments regarding applicability and appropriate components for use in defining a person's compliance history.

SECTION DISCUSSION

Proposed new §60.1, Compliance History, would implement the requirements of TWC, §5.753. Specifically, the proposed language would establish the components of compliance history the agency must consider prior to certain decisions. In this phase of rulemaking associated with the implementation of HB 2912, §4.01 regarding compliance history, the way the agency will use compliance history in certain decisions is not addressed; rather, this proposed language would only address the applicability and components of compliance history.

The commission proposes new §60.1(a), Applicability. The proposed subsection states that the chapter would be applicable to persons subject to the requirements of TWC, Chapters 26 and 27 and THSC, Chapters 361, 382, and 401. The proposed subsection would mirror HB 2912, §4.01, as it creates new TWC, §5.754(e) by specifying that the agency will utilize compliance history when making decisions regarding the issuance, renewal, amendment, modification, denial, suspension, or revocation of a permit; enforcement; the use of announced inspections; and participation in innovative programs. This proposed subsection would also specify that, for purposes of this proposed new chapter, "permit" means licenses, certificates, registrations, approvals, permits by rule, standard permits, or other forms of authorization. This is to reflect the definition of "permit" included in TWC, §5.751. Additionally, the term "person" is the same as found in 30 TAC Chapter 3.

The types of permits, licenses, certificates, registrations, approvals, permits by rule, and standard permits over which the commission has jurisdiction can be categorized into two groups. The first group can be referred to as a "no decision" process. This term refers to a situation in which a person informs the agency, as required by rule, that it is engaging in a certain regulated activity for which there is no specific authorization required. This includes, for example, changes to qualified facilities under 30 TAC §116.117 and §116.118. Additionally, the "no decision" process includes activities that are authorized by rule for which notification may or may not be required, but no agency response is required for the site to be authorized. The following are examples of required notifications that do not require response by the agency: the on-site management of nonhazardous waste for which a notification is required by 30 TAC §335.6; underground or aboveground storage tanks registered under 30 TAC §334.7 or §334.127; emissions authorized by 30 TAC Chapter 106, where no written site approval is required; emissions authorized by Chapter 116, Subchapter F of this title (relating to Standard Permits), where no written site approval is required; and waste discharge notices of intent under 30 TAC Chapter 205, where no written approval is required.

Other types of permits can be referred to as a "decision" process. This group includes authorizations which require notification or application, an agency review, and site-specific agency approval or response. Examples of this category include municipal solid waste transfer stations as required by 30 TAC §330.65, and tire processing facilities as required by 30 TAC §328.63. This category also includes the more traditional permit decisions, such as authorization for an air permit under 30 TAC §116.111, and authorization for a Class I underground injection control well under 30 TAC §331.7. Proposed new §60.1 would only be applied to those permits or other forms of authorization, including temporary authorizations, requiring the "decision" process.

The commission considered whether the actions under Chapter 101, Subchapter H of this title, relating to Emissions Banking and Trading, are subject to the compliance history review requirements. The commission determined that these actions are not subject to the compliance history review requirements because they are not a form of authorization. The actions under Subchapter H are compliance methods for achieving the emissions reductions required under the state implementation plan as required by 30 TAC Chapter 117, and providing flexibility for compliance with 30 TAC Chapters 115 and 117.

The commission considered whether executive director actions regarding the remediation of spills or other contamination are subject to the compliance history review requirements. These actions are required under commission rules and the executive director reviews the actions taken during remediation to determine compliance with the rules and gives approval to implement the next requirement. The executive director is not authorizing any new activity and thus the commission determined that these actions are not subject to the compliance history review requirements.

The commission also considered whether there are specific kinds of permit actions which do not extend new authorizations. The commission suggests that permit actions such as voluntary permit revocations; minor amendments and nonsubstantive corrections to permits; TPDES and underground injection control minor permit modifications; Class 1 solid waste modifications, except for changes in ownership; municipal solid waste Class I modifications, except for temporary authorizations and municipal solid waste Class I modifications requiring public notice; permit alterations; and administrative revisions, do not change the current authorizations, but add clarity, correct typographical errors, update contact information, or make other minor changes where the minor changes are equally protective of human health and the environment. Therefore, the commission proposes that this rule would not be applicable to these types of permit actions, unless a motion for reconsideration or a motion to overturn is filed under 30 TAC §50.39 or §50.139 with respect to the listed permit actions.

The proposal would reflect that Chapter 60 does not apply to occupational licensing programs under the jurisdiction of the commission, which is stated in TWC, §5.751.

With regard to required implementation dates, as specified in HB 2912, §18.05, the proposed subsection reflects that new Chapter 60 applies as follows: in the consideration of compliance history for decisions by the agency relating to the issuance, amendment, modification, or renewal of permits under TWC, §§5.754, 26.028, 26.0281, 26.040, and 27.018, and THSC, §§361.084, 361.088, 361.089, 382.0518, 382.055, 382.056, 401.110, and 401.112, only to applications submitted on or after September 1, 2002; in the consideration of compliance history for actions taken by the agency relating to inspections and flexible permitting, effective September 1, 2002; and in the consideration of compliance history in decisions of the commission relating to the suspension or revocation of a permit or the imposition of a penalty in a matter under the jurisdiction of the commission, only to a proceeding that is initiated or an action that is brought on or after September 1, 2002. Additionally, the commission proposes that the compliance history requirements apply to decisions by the executive director relating to other forms of authorization and innovative programs to begin September 1, 2002.

The commission proposes new §60.1(b), Components, to specify the components of compliance history that the agency must consider under applicable circumstances. The components of compliance history as specified in proposed Chapter 60 shall apply to an action taken by the agency on or after February 1, 2002, as specified in HB 2912, §18.05. The proposed new subsection states that compliance history shall include multimedia compliance- related information about a person, specific to the site which is under review as well as other sites which are under the commission's jurisdiction and owned or operated by the same person. The proposed language would further require that compliance history cover at least a five-year period. This would include at least the five years prior to the date the permit application is received by the executive director; the five-year period preceding the date of the inspection that initiates enforcement; with regard to the use of announced inspections, the five-year period preceding an inspection; or the five-year period preceding the date the application for participation in an innovative program is received by the executive director. This is reflected in the proposed language to establish by rule "a period for compliance history" as required by TWC, §5.753(e). The agency may develop a compliance history for a longer period based upon case-by-case considerations. For example, the agency may develop a five-year compliance history based upon the receipt date of an application, and then supplement the history for the time period needed to process a permit application. The proposed minimum five-year period is consistent with the length of time currently utilized in preparing many compliance summaries, and is also the length of time used in evaluating compliance history for purposes of commission enforcement actions. The commission believes that a minimum five- year period of time is both adequate and reasonable for consideration of compliance history because this time period is long enough to detect any overall pattern related to compliance.

With regard to the actual components of compliance history, the commission first proposes new §60.1(b)(1), which mirrors TWC, §5.753(b)(1). This paragraph provides that one component of compliance history must include any enforcement orders, court judgments, consent decrees, and criminal convictions of this state and the federal government relating to compliance with an environmental law, regulation, permit, order, consent, decree, or other requirement under the jurisdiction of the commission or the EPA.

The commission proposes new §60.1(b)(2), to comply with the requirement of TWC, §5.753(b)(2), which provides that, notwithstanding any other provision of the TWC, orders issued under TWC, §7.070 must be included in the agency's consideration of compliance history. The proposed language would further specify use of orders issued under TWC, §7.070 on or after February 1, 2002. This is because currently, commission orders issued under TWC, §7.070 include language specifically stating that the order is not intended to become a part of the respondent's compliance history. As of the effective date of TWC, §5.753(b)(2), which is February 1, 2002, the compliance history portion of TWC, §7.070 is superceded, and orders issued under this section of the statute will be considered in compliance history. In the interim, the commission will also modify the existing language in applicable proposed enforcement orders to reflect the February 1, 2002 change to these types of orders.

The commission proposes new §60.1(b)(3), which would require that, to the extent readily available to the executive director, enforcement orders, court judgments, and criminal convictions relating to violations of environmental laws of other states must be considered as a component of compliance history. This component is required by TWC, §5.753(b)(3). The commission intends to utilize the EPA Integrated Compliance Information System and its retrieval component, Online Tracking Information System or any subsequent equivalent system(s) to retrieve the administrative and civil enforcement information which is extracted from the program-specific EPA data bases. Commission decisions regarding compliance history that are based upon information contained on the EPA Integrated Compliance Information System shall not be voided by the subsequent discovery of enforcement orders and court judgments relating to violations of environmental laws of other states that were not noted in the EPA Integrated Compliance Information System.

The commission proposes new §60.1(b)(4), which would require that chronic excessive emissions events be included as a component of compliance history. This implements HB 2912, §4.01, which adds chronic excessive emissions events as a statutory requirement in new THSC, §382.0216(j). The proposed paragraph would further state that, for purposes of new Chapter 60, the term "emissions event" is the same as defined in THSC, §382.0215(a).

The commission proposes new §60.1(b)(5), mirroring the language in TWC, §5.753(c), which states that any information required by other law or any requirement necessary to maintain federal program authorization must be included as a compliance history component.

The commission proposes new §60.1(b)(6), which would require that the dates of investigations conducted by the executive director or his contractors be included as a component of compliance history. This information would reflect how many investigations have taken place during the five-year compliance period, allowing for a better perspective with regard to the other components of compliance history, especially those in proposed paragraphs (1)- (5), and (7). For example, it would be important to know whether the facility had been inspected during the compliance period, and how many times, when there are no notices of violations or orders present during the compliance period.

The commission proposes new §60.1(b)(7) which states that all written notices of violation issued on or after February 1, 2002 must be included as a component of compliance history, specifying each violation of an environmental law, regulation, permit, order, consent decree, or other requirement. This requirement implements TWC, §5.753(d), which further states that a notice of violation administratively determined to be without merit will not be included in a compliance history. Additionally, a notice of violation that is included in a compliance history will be removed from the compliance history if the commission subsequently determines that the notice of violation was without merit. The commission is proposing the use of written notices of violation issued on or after February 1, 2002 to allow the agency to complete a more efficient tracking system and to develop specific procedures to re-evaluate complex violations as needed.

The commission suggests that there are other components of compliance history that it should consider to fully evaluate a person's commitment to environmental excellence. Therefore, the commission proposes new §60.1(b)(8), which would require, as applicable, the date of letters notifying the executive director of an intended audit conducted under the Texas Environmental, Health, and Safety Audit Privilege Act, 74th Legislature, 1995, to be included as a component of compliance history. These voluntary compliance audits can be a useful tool for members of the regulated community to determine if their practices conform to all applicable regulations.

The commission also proposes new §60.1(b)(9), which would require the type of environmental management systems (EMSs), if any, used for environmental compliance to be included as a component of compliance history. Environmental management systems are another voluntary tool that the regulated community may use to evaluate their own environmental management practices, confirm compliance with environmental rules and regulations, and emphasize management oversight of regulated activities.

The commission recognizes that small entities are very concerned about environmental compliance but may not have the resources needed to conduct detailed assessments of their regulated activities. Therefore, the commission proposes new §60.1(b)(10), which would require any voluntary on-site compliance assessments conducted by the executive director under a special assistance program, such as assessments conducted by Small Business Environmental Assistance Division under the site visit program to be included as a component of compliance history. These voluntary assessments are conducted upon request.

The commission also recognizes that voluntary pollution reduction program is an important tool in addressing environmental concerns in the state beyond regulatory requirements, and reflects a person's commitment to environmental excellence. Therefore, the commission proposes new §60.1(b)(11), which would require participation in a voluntary pollution reduction program to be included as a component of compliance history.

The commission proposes new §60.1(b)(12), which would require, as a part of compliance history, a description of early compliance with or offer of a product that meets future state or federal government environmental requirements. Accelerating the implementation of new requirements that are intended to benefit the environment is a choice that a person may make. This voluntary early compliance is also a reflection of a person's commitment to environmental excellence.

Finally, with regard to the components of compliance history, the commission proposes new §60.1(b)(13), which requires that the name and telephone number of an agency staff person to contact for additional information regarding compliance history be included.

It should be noted that in proposed new Chapter 60, the commission does not include existing 30 TAC §281.21(d)(1) and (3) pertaining to the date(s) and description of any citizen complaints received; and for each inspection, whether a condition of noncompliance was alleged by the investigator and a brief description of the resulting environmental impact and, for radioactive material licenses, any impact on radiation safety. These items are not specifically included in TWC, §5.753 as required components of compliance history, and further, other components included in this proposal would, in effect, include pertinent aspects of this same information. For instance, a citizen may file a complaint regarding an environmental incident. The executive director will investigate, and if a violation is documented, then the executive director will issue a notice of violation or initiate enforcement, as appropriate. Thus, the complaint would be part of the compliance history via the notice of violation or commission order. The commission notes that during the legislative process citizen complaints were not included in HB 2912.

Additionally, it should be noted that, in proposed new Chapter 60, the commission does not include the existing requirement, 30 TAC §281.21(d)(5), which states that, for applicable facilities, the date(s) and description of any incident the applicant reported to the executive director which required implementation of the facility's contingency plan is to be included as a component of compliance history. It is not a statutory requirement that this information be included as a component of compliance history, nor is it a requirement that is necessary to maintain federal authorization. Additionally, the implementation of HB 2912, §4.01, is intended to develop a uniform standard for the agency to use in evaluating compliance history, and existing 30 TAC §281.21(d)(5) only applies to a limited portion of the permits issued by the commission; therefore, the commission suggests that this item not be included in new Chapter 60.

In proposed new Chapter 60, the commission does not include notices of violations issued by the EPA, which are currently a component of air permit compliance histories, required in 30 TAC §116.122. The commission suggests that EPA notices of violations not be considered because it does not have the opportunity to evaluate the merit of those notices of violations.

The commission proposes new §60.1(c), Change in Ownership, which would state that if ownership of the site changed during the minimum five-year compliance period, a distinction of compliance history of the site under each owner during that five-year period shall be made. Specifically, the proposed language states that for any part of the compliance period that involves a different, previous owner, the compliance history would be assessed for only the site under review. The distinction for previous owners is that proposed §60.1(b) would require that for the current owner of the site, the compliance history would look at the site under review as well as other sites which are under the commission's jurisdiction and owned or operated by the same person.

The commission has determined that for purposes of developing compliance histories, "ownership" would only include the entity filing the permit application, under enforcement, being inspected, or applying for participation in an innovative program, as defined by its legal name. For example, any parent, sister, or daughter corporations related to the legal entity would not be included. This would change current agency practice.

FISCAL NOTE: COSTS TO STATE AND LOCAL GOVERNMENT

John Davis, Technical Specialist with Strategic Planning and Appropriations, determined that for the first five-year period the proposed rule is in effect, there will be no fiscal implications for units of state and local government as a result of administration and enforcement of the proposed rule, which is intended to implement certain provisions of HB 2912, 77th Legislature, 2001. The proposed rule is procedural in nature and is not anticipated to result in additional costs for units of state and local government.

The commission currently has procedures for preparation of compliance summaries for waste disposal and air emission permit applications, enforcement actions, and participation in the voluntary Clean Texas Program; however, these procedures are not standardized. House Bill 2912 requires the commission to standardize procedures and broaden the use of compliance histories to cover more applications before the commission, including licenses, certificates, registrations, approvals, permits by rule, standard permits, and other forms of authorizations issued by the agency. In order to comply with the compliance history provision of HB 2912, the commission proposes two rulemaking phases. This rulemaking is phase I and consists of defining the applicability and components of compliance history. Phase II, to be proposed in a separate rulemaking, is the actual implementation phase and will detail how compliance histories will be used in applicable decisions made by the agency, including decisions regarding permit issuance, renewal, amendment, modification, denial, suspension, or revocation; enforcement; the use of unannounced inspections; and participation in innovative programs.

The proposed rule in phase I is intended to implement uniform standards for evaluating compliance histories by defining the components to be included in all evaluations. The compliance history reviews will cover all media, including air, water and waste, and will include the following components: enforcement orders; court judgments; consent decrees; criminal convictions of this state and the federal government relating to compliance with an environmental law; regulation, permit, order, consent decree, or other requirements under the jurisdiction of the commission or the EPA; and orders issued regarding findings of fact. The reviews, to the extent readily available, will also consist of enforcement orders, court judgments, and criminal convictions relating to violations of environmental laws of other states; chronic excessive emissions events; any information required by other law or any requirements necessary to maintain federal program authorization; dates of investigations; notices of violations; any notices of audits conducted under the Texas Environmental, Health, and Safety Audit Privilege Act; and the type of EMSs used for environmental compliance; and a description of early compliance with or offer of a product that meets future state or federal government requirements. Additionally, the following components will be included in the reviews: any voluntary onsite compliance assessments conducted by the executive director under a special assistance program; participation in a voluntary pollution reduction program; and the name and telephone number of an agency staff person to contact for additional information regarding compliance history. Changes in ownership would also be reflected.

This rulemaking is procedural in nature and does not propose additional regulatory requirements for units of state and local government; therefore, the commission anticipates no additional costs due to implementation of the proposed rule. Additionally, since this rulemaking only defines the components to be used in compliance history summaries, the commission anticipates no additional costs to the agency due to implementation of this rulemaking phase.

PUBLIC BENEFIT AND COSTS

Mr. Davis also determined that for each year of the first five years the proposed rule is in effect, the public benefit anticipated from enforcement of and compliance with this rulemaking will be standardized procedures to be used by the commission during compliance history reviews to ensure regulated entities are adhering to applicable regulations.

The commission currently has procedures for preparation of compliance summaries for waste disposal and air emission permit applications, enforcement actions, and participation in the voluntary Clean Texas Program; however, these procedures are not standardized. House Bill 2912 requires the commission to standardize procedures and broaden the use of compliance histories to cover more applications before the commission, including licenses, certificates, registrations, approvals, permits by rule, standard permits, and other forms of authorizations issued by the commission. House Bill 2912 further requires compliance histories to be used in applicable decisions made by the agency, including decisions regarding permit issuance, renewal, amendment, modification, denial, suspension, or revocation; enforcement; the use of unannounced inspections; and participation in innovative programs.

The proposed rule is intended to implement uniform standards for evaluating compliance histories by defining the components to be included in all evaluations. This rulemaking is procedural in nature and does not propose additional regulatory requirements; therefore, the commission does not anticipate fiscal implications for individuals and businesses to comply with the proposed rule.

SMALL BUSINESS AND MICRO-BUSINESS ASSESSMENT

There will be no adverse fiscal impacts to any small or micro-business as a result of the proposed rule, which is intended to implement certain provisions of HB 2912. The commission currently has procedures for preparation of compliance summaries for waste disposal and air emission permit applications, enforcement actions, and participation in the voluntary Clean Texas Program; however, these procedures are not standardized. House Bill 2912 requires the commission to standardize procedures and broaden the use of compliance histories to cover more applications before the commission, including licenses, certificates, registrations, approvals, permits by rule, standard permits, and other forms of authorizations issued by the commission. House Bill 2912 further requires compliance histories to be used in applicable decisions made by the agency, including decisions regarding permit issuance, renewal, amendment, modification, denial, suspension, or revocation; enforcement; the use of unannounced inspections; and participation in innovative programs.

The proposed rule is intended to implement uniform standards for evaluating compliance histories by defining the components to be included in all evaluations. This rulemaking is procedural in nature and does not propose additional regulatory requirements; therefore, the commission does not anticipate fiscal implications for small or micro-businesses to comply with the proposed rule.

LOCAL EMPLOYMENT IMPACT

The commission has reviewed this proposed rulemaking and determined that a local employment impact statement is not required because the proposed rule does not adversely affect a local economy in a material way for the first five years that the proposed rule is in affect.

REGULATORY IMPACT ANALYSIS DETERMINATION

The commission has reviewed the proposed rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and determined that the rulemaking is not subject to §2001.0225 because it does not meet the definition of a "major environmental rule" as defined in that statute. Although the intent of this rule is to protect the environment and reduce the risk to human health from environmental exposure, this is not a "major environmental rule" because it does not 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 rule will not 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 because the rule merely adds the new requirements relating to the components of compliance history. These requirements are contained in TWC, §5.753. The reason there is no adverse effect in a material way on the environment, or the public health and safety of the state or a sector of the state is because this proposed rule is designed to protect the environment, the public health, and the public safety of the state and all sectors of the state. Furthermore, the proposed rule does not meet any of the four applicability requirements listed in §2001.0225(a). The proposed rule does not exceed a standard set by federal law, because there is no comparable federal law. The proposed rule does not exceed an express requirement of state law, because it is consistent with the requirements of TWC, §5.753. The proposed rule does not exceed the requirements of a delegation agreement because there is no applicable delegation agreement. The proposed rule is not proposed to be adopted solely under the general powers of the agency, but will be adopted under the express requirements of TWC, §5.753. The commission invites public comment on the draft regulatory impact analysis determination.

TAKINGS IMPACT ASSESSMENT

The commission has prepared a takings impact assessment for this proposed rule in accordance with Texas Government Code, §2007.043. The following is a summary of that assessment. Texas Government Code, §2007.003(b)(4), provides that Chapter 2007 does not apply to this proposed rule since it is reasonably taken to fulfill an obligation mandated by state law. The specific purpose of this proposed rule is to incorporate the new requirements relating to the components of compliance history, which are contained in TWC, §5.753. Promulgation and enforcement of this proposed rule would not affect private real property which is the subject of the rule because the proposed rule language merely incorporates the new requirements relating to the components of compliance history, which are contained in TWC, §5.753. The subject proposed rule does not affect a landowner's rights in private real property.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission reviewed the proposed rulemaking and found that the rule is neither identified in Coastal Coordination Act Implementation Rules, 31 TAC §505.11, nor will it affect any action/authorization identified in Coastal Coordination Act Implementation Rules, 31 TAC §505.11. Therefore, the proposed rule is not subject to the Coastal Management Program.

ANNOUNCEMENT OF HEARING

A public hearing on this proposal will be held in Austin on November 12, 2001, at 10:00 a.m. at the commission's central office, Building F, Room 2210, located at 12100 Park 35 Circle. The hearing will be structured for the receipt of oral or written comments by interested persons. Individuals may present oral statements when called upon in order of registration. There will be no open discussion during the hearing; however, an agency staff member will be available to discuss the proposal 30 minutes prior to the hearing and will answer questions before and after the hearing.

SUBMITTAL OF COMMENTS

Comments may be submitted to Joyce Spencer, Office of Environmental Policy, Analysis, and Assessment, MC 205, P.O. Box 13087, Austin, Texas 78711-3087 or faxed to (512) 239-4808. Comments must be received by 5:00 p.m., November 12, 2001, and should reference Rule Log Number 2001-070-060-AD. For further information, please contact Debra Barber, Policy and Regulations Division, at (512) 239-0412.

STATUTORY AUTHORITY

The new section is proposed under THSC, §361.017 and §361.024, which provides the commission with the authority to adopt rules necessary to carry out its power and duties under the Texas Solid Waste Disposal Act; THSC, §382.017, which provides the commission with the authority to adopt rules consistent with the policy and purposes of the Texas Clean Air Act; and THSC, §401.051, which provides the commission with authority to adopt rules and guidelines relating to the control of sources of radiation under the Texas Radiation Control Act. The new rule is also authorized under TWC, §5.103, which provides the commission authority to adopt any rules necessary to carry out its powers and duties under this code and other laws of this state and to adopt rules repealing any statement of general applicability that interprets law or policy; and §5.105, which authorizes the commission to establish and approve all general policy of the commission by rule.

The proposed new rule implements TWC, §5.753, relating to the standard for evaluating compliance history.

*§60.1. Compliance History.*

(a) Applicability. The provisions of this chapter are applicable to all persons subject to the requirements of Texas Water Code (TWC), Chapters 26 and 27, and Texas Health and Safety Code (THSC), Chapters 361, 382, and 401. Specifically, the agency will utilize compliance history when making decisions regarding the issuance, renewal, amendment, modification, denial, suspension, or revocation of a permit; enforcement; the use of announced inspections; and participation in innovative programs. For purposes of this chapter, the term "permit" means licenses, certificates, registrations, approvals, permits by rule, standard permits, or other forms of authorization. This rule only applies to forms of authorization, including temporary authorizations, that require some level of notification to the agency; review; and approval or response. In addition, this rule does not apply to permit actions such as voluntary permit revocations; minor amendments and nonsubstantive corrections to permits; Texas pollutant discharge elimination system and underground injection control minor permit modifications; Class 1 solid waste modifications, except for changes in ownership; municipal solid waste Class I modifications, except for temporary authorizations and municipal solid waste Class I modifications requiring public notice; permit alterations; and administrative revisions, unless a motion for reconsideration or a motion to overturn is filed under 30 TAC §50.39 or §50.139 of this title (relating to Motion for Reconsideration; and Motion to Overturn Executive Director's Decision; respectively) with respect to the listed permit actions. Further, this chapter does not apply to occupational licensing programs under the jurisdiction of the commission. This chapter applies:

(1) in the consideration of compliance history for decisions by the agency relating to the issuance, amendment, modification, or renewal of permits, only to applications submitted on or after September 1, 2002;

(2) in the consideration of compliance history for actions taken by the agency relating to inspections and flexible permitting, effective September 1, 2002;

(3) in the consideration of compliance history in decisions of the commission relating to the suspension or revocation of a permit or the imposition of a penalty in a matter under the jurisdiction of the commission, only to a proceeding that is initiated or an action that is brought on or after September 1, 2002; and

(4) with respect to compliance history, for an action taken by the executive director on other forms of authorization, or participation in an innovative program, except for flexible permitting, effective September 1, 2002.

(b) Components. The components of compliance history as specified in this chapter shall apply to an action taken by the agency on or after February 1, 2002. The compliance history shall include multimedia compliance-related information about a person, specific to the site which is under review, as well as other sites which are under the commission's jurisdiction and owned or operated by the same person. The compliance history shall cover at least a five-year period. The compliance period includes at least the five years prior to the date the permit application is received by the executive director; the five-year period preceding the date of the inspection that initiates enforcement; for purposes of determining whether an announced inspection is appropriate, the five-year period preceding an inspection; or the five-years prior to the date the application for participation in an innovative program is received by the executive director. The components are:

(1) any enforcement orders, court judgments, consent decrees, and criminal convictions of this state and the federal government relating to compliance with an environmental law, regulation, permit, order, consent decree, or other requirement under the jurisdiction of the commission or the EPA;

(2) notwithstanding any other provision of the TWC, orders issued under TWC, §7.070 on or after February 1, 2002;

(3) to the extent readily available to the executive director, enforcement orders, court judgments, and criminal convictions relating to violations of environmental laws of other states;

(4) chronic excessive emissions events. For purposes of this chapter, the term "emissions event" is the same as defined in THSC, §382.0215(a);

(5) any information required by law or any compliance-related requirement necessary to maintain federal program authorization;

(6) the dates of investigations;

(7) all written notices of violation issued on or after February 1, 2002, except for those administratively determined to be without merit, specifying each violation of an environmental law, regulation, permit, order, consent decree, or other requirement;

(8) the date of letters notifying the executive director of an intended audit conducted under the Texas Environmental, Health, and Safety Audit Privilege Act, 74th Legislature, 1995;

(9) the type of environmental management systems, if any, used for environmental compliance;

(10) any voluntary on-site compliance assessments conducted by the executive director under a special assistance program;

(11) participation in a voluntary pollution reduction program;

(12) a description of early compliance with or offer of a product that meets future state or federal government environment requirements; and

(13) the name and telephone number of an agency staff person to contact for additional information regarding compliance history.

(c) Change in ownership. In addition to the requirements in subsection (b) of this section, if ownership of the site changed during the five-year compliance period, a distinction of compliance history of the site under each owner during that five-year period shall be made. Specifically, for any part of the compliance period that involves a different owner, the compliance history will be assessed for only the site under review.

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 September 27, 2001.

TRD-200105852
Stephanie Bergeron
Division Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 239-5017

♦ ♦ ♦

## CHAPTER 290. PUBLIC DRINKING WATER
## SUBCHAPTER E. FEES FOR PUBLIC WATER SYSTEMS

### 30 TAC §290.51

The Texas Natural Resource Conservation Commission (commission) proposes an amendment to §290.51, Fees for Services to Drinking Water System.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE PROPOSED RULE

House Bill (HB) 2912, §3.07, 77th Legislature, 2001 mandates the commission to consider equity in the establishment of the public drinking water fee rates. The proposed amendment to this chapter is intended to consider equity while generating overall revenue at the current revenue stream. The revenue generated from the new fee assessment does not exceed the amount appropriated by the legislature for fiscal year (FY) 2002, nor is it greater than the revenue generated under the previous assessment in FY 2001.

SECTION DISCUSSION

The proposed amendment to §290.51(a)(3) deletes the existing language and replaces it with a new §290.51(a)(3) that calculates the fees the commission will charge for services provided to community and nontransient noncommunity water systems using a more simplified and equitable method. The proposed amendment provides that for a system with fewer than 25 connections, the fee will be $75; for systems with 25 - 99 connections, the fee will be $150; and for a system with greater than or equal to 100 connections, the fee will be calculated as $c^{0.75}$ X $4.80, where "c" is the number of connections. The remaining language in the section has only been reformatted for readability.

FISCAL NOTE: COSTS TO STATE AND LOCAL GOVERNMENT

John Davis, Technical Specialist with Strategic Planning and Appropriations, has determined that for the first five-year period the proposed amendment is in effect, there will be fiscal implications, which may be significant, for units of state and local government as a result of administration and enforcement of the proposed amendment. The overall fiscal impact to units of state and local government affected by the proposed amendment is approximately $228,000 annually in additional fees.

This rulemaking is intended to consider equity when assessing public drinking water system fees. The commission anticipates that approximately 80% (1,593) of the 2,000 affected units of state and local government will either pay the same or reduced fees to comply with the proposed amendment. The majority of the remaining 407 systems will pay less than $1,000 annually in increased fees to comply with the proposed amendment. However, the five largest public drinking water systems in Texas, located in Houston, Dallas, Ft. Worth, Austin, and San Antonio will pay between $13,000 to $90,000 more annually to comply with the proposed amendment.

All governmental entities that currently pay the public services fee potentially may be affected. The fee calculation will change and the amount of the fee is determined by the number of connections from the most recent field inspection report. The governmental entities affected would be cities, counties, state and federal government if they supply drinking water to the general public.

The proposed amendment is intended to implement certain provisions of HB 2912 (an act relating to the continuation and functions of the commission; providing penalties). The bill requires the commission to consider equity in the establishment of the public drinking water fee rates, while generating revenue to cover the costs of the commission's public drinking water program. The proposed amendment is intended to restructure the public drinking water fee rate so that smaller drinking water systems pay reduced fees to comply with commission regulations, while maintaining sufficient revenues to cover program costs.

The proposed amendment is intended to introduce standard fee rates for smaller drinking water systems in lieu of using formulas based on the number of connections a system has. For a system with fewer than 25 connections, the annual fee rate will be $75. For systems with 25 - 99 connections, the annual fee rate will be $150. The annual fee rate formula for systems with greater than or equal to 100 connections will be modified, resulting in lower fees for the majority of systems with over 100 connections.

For example, the fee for a public drinking water system that services 24 connections will be reduced by approximately $50 ($2.08 per connection) per year, while the fee for a system that services 99 connections will be reduced by approximately $120 ($1.21 per connection) per year. Drinking water systems will not pay more than $1,000 annually to comply with the proposed amendment unless they service over 11,000 connections per year. There are approximately 80 government owned and operated public drinking water systems that meet this criteria. All but five of these systems will pay under $10,000 more annually to comply with the proposed amendment. The five systems that will pay in excess of $10,000 more are located in Houston, Dallas, Ft. Worth, Austin, and San Antonio, and will pay between $13,000 to $90,000 more annually to comply with the proposed amendment. The total fiscal impact to units of state and local government is anticipated to be approximately $228,000 more annually to comply with the proposed amendment.

The commission does not anticipate significant impacts to agency revenues due to implementation of the proposed amendment. House Bill 2912 requires the agency to set fee rates sufficient to cover the costs to administer and enforce the commission's public drinking water program. The commission anticipates the proposed rulemaking will result in an annual $8,000 increase in agency revenues.

PUBLIC BENEFITS AND COSTS

Mr. Davis also determined that for each year of the first five years the proposed amendment is in effect, the public benefit anticipated from enforcement of and compliance with this rulemaking will be the consideration of fee equity when assessing public drinking water system fees.

All businesses that currently pay the public services fee potentially may be affected. The fee calculation will change and the amount of the fee is determined by the number of connections from the most recent field inspection report. The businesses affected would be companies, hotels and other various businesses, if they supply drinking water to the general public.

The proposed amendment is intended to introduce standard fee rates for smaller drinking water systems in lieu of using formulas based on the number of connections a system has. For a system with fewer than 25 connections, the annual fee rate will be $75. For systems with 25 - 99 connections, the annual fee rate will be $150. The annual fee rate formula for systems with greater than or equal to 100 connections will be modified, resulting in lower fees for the majority of systems with over 100 connections.

For example, the fee for a public drinking water system that services 24 connections will be reduced by approximately $50 ($2.08 per connection) per year, while the fee for a system that services 99 connections will be reduced by approximately $120 ($1.21 per connection) per year. Drinking water systems will not pay more than $1,000 annually to comply with the proposed amendment unless they service over approximately 11,000 connections per year. Based on the latest fee and revenue data, the commission anticipates that none of the 4,456 individuals and businesses affected by the proposed amendment will pay $1,000 more annually to comply with the proposed amendment. The commission anticipates an approximate annual $220,000 cost savings to individuals and businesses to comply with the proposed amendment.

SMALL BUSINESS AND MICRO-BUSINESS ASSESSMENT

There will be adverse fiscal impacts to small or micro-businesses, which are not anticipated to be significant, due to implementation of the proposed amendment. However, the majority of affected small and micro-businesses will experience cost savings.

The proposed amendment is intended to introduce standard fee rates for smaller drinking water systems in lieu of using formulas based on the number of connections a system has. For a system with fewer than 25 connections, the annual fee rate will be $75. For systems with 25 - 99 connections, the annual fee rate will be $150. The annual fee rate formula for systems with greater than or equal to 100 connections will be modified, resulting in lower fees for the majority of systems with over 100 connections.

For example, the fee for a public drinking water system that services 24 connections will be reduced by approximately $50 ($2.08 per connection) per year, while the fee for a system that services 99 connections will be reduced by approximately $120 ($1.21 per connection) per year. Drinking water systems will not pay more than $1,000 annually to comply with the proposed amendment unless they service over approximately 11,000 connections per year. Based on the latest fee and revenue data, the commission anticipates that none of the 4,456 individuals and businesses, some of which are small or micro-businesses, affected by the proposed amendment will pay $1,000 more annually to comply with the proposed amendment. The commission anticipates an approximate $220,000 annual cost savings to individuals and businesses to comply with the proposed amendment.

All businesses that currently pay the public services fee potentially may be affected. The fee calculation will change and the amount of the fee is determined by the number of connections from the most recent field inspection report. The businesses affected would be restaurants, trailer parks, and other various small businesses, if they supply drinking water to the general public.

The following is an analysis of the potential costs per employee for small or micro-businesses affected by the proposed amendment. The commission has chosen to use $100 for the following analysis since over 96% of known businesses that would have to pay increased fees will pay $100 or less to comply with the proposed amendment. Small and micro-businesses are defined as having fewer than 100 or 20 employees respectively. A small business that supports approximately 1,500 water connections annually would incur costs of approximately $1.00 per employee every year to comply with the proposed rule. A micro-business that supports approximately 1,500 water connections annually would incur costs of approximately $5.00 per employee every year to comply with the proposed rule.

LOCAL EMPLOYMENT IMPACT STATEMENT

The commission has reviewed this proposed rulemaking and determined that a local employment impact statement is not required because the proposed rule does not adversely affect a local economy in a material way for the first five years that the proposed rulemaking is in affect.

DRAFT REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed the proposed rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225 and determined the rulemaking is not subject to §2001.0225 because it does not meet the definition of a "major environmental rule." "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, 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. This rulemaking is administrative only and considers equity while generating overall revenue at the current revenue stream. Therefore, the rulemaking does not meet the definition of "major environmental rule" because the rulemaking is not specifically intended to protect the environment or reduce risks to human health from environmental exposure.

Furthermore, the proposed rule does not meet any of the four applicability requirements listed in §2001.0225(a). The proposed rule does not exceed a standard set by federal law. The proposed rule does not exceed an express requirement of state law, because it is authorized by and consistent with the requirements of THSC, §341.041(a), as amended by HB 2912, §3.07. The proposed rule does not exceed the requirements 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 because the rule is consistent with, and does not exceed, federal requirements and is in accordance with THSC, §341.041(a), which requires the commission to establish fees sufficient to cover the costs of administering the federal Safe Drinking Water Act. The proposed rule is not proposed to be adopted solely under the general powers of the agency, but will be adopted under the express requirements of THSC, §341.041(a).

Written comments on the draft regulatory impact analysis determination may be submitted to the contact person at the address listed under the SUBMITTAL OF COMMENTS section of this preamble.

TAKINGS IMPACT ASSESSMENT

The commission conducted a takings impact assessment for this rule under Texas Government Code, §2007.043. The specific purpose of this rulemaking is to consider equity while generating overall revenue at the current revenue stream. The rulemaking contains administrative rule changes only and does not affect private real property. Therefore, the rulemaking will not constitute a takings under Texas Government Code.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission reviewed the rulemaking and found that the proposed rule amendment is neither identified in the Coastal Coordination Act Implementation Rules, 31 TAC §505.11, relating to Actions and Rules subject to the Texas Coastal Management Program (CMP), nor does it affect any action or authorization identified in §505.11. This proposed rulemaking concerns only administrative rules of the commission intended to consider equity while generating overall revenue at the current revenue stream. Therefore, the rulemaking is not subject to the CMP.

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

ANNOUNCEMENT OF HEARING

The commission will hold a public hearing on this proposal in Austin on November 8, 2001 at 10:00 a.m. in Building C, Room 131E, at the commission's central office located at 12100 Park 35 Circle. The hearing is structured for the receipt of oral or written comments by interested persons. Individuals may present oral statements when called upon in order of registration. Open discussion will not be permitted during the hearing; however, commission staff members will be available to discuss the proposal 30 minutes before the hearing and will answer questions before and after the hearing.

Persons with disabilities who have special communication or other accommodation needs who are planning to attend the hearing should contact the Office of Environmental Policy, Analysis, and Assessment at (512) 239-4900. Requests should be made as far in advance as possible.

SUBMITTAL OF COMMENTS

Comments may be submitted to Patricia Durón, Office of Environmental Policy, Analysis, and Assessment, MC 205, P.O. Box 13087, Austin, Texas 78711-3087 or faxed to (512) 239-4808. All comments should reference Rule Log Number 2001-099-290-WT. Comments must be received by 5:00 p.m., November 12, 2001. For further information or questions concerning this proposal, please contact Debi Dyer, Policy and Regulations Division, at (512) 239-3972.

STATUTORY AUTHORITY

The amendment is proposed under Texas Water Code (TWC), §5.103 and §5.105, which establish the commission's general authority to adopt rules; and THSC, §341.041(a), as amended by HB 2912, §3.07, which states that the commission may charge fees sufficient to cover the reasonable costs of administering the programs and services of the federal Safe Drinking Water Act and requires the commission to consider equity among persons required to pay the fees when setting the amount of the fees.

The amendment implements HB 2912, §3.07.

*§290.51. Fees for Services to Drinking Water System.*

(a) Purpose and scope.

(1) - (2) (No change.)

(3) The fees which the commission will charge for services provided to community and nontransient noncommunity water systems under this subsection will be according to the following schedule.

(A) For a system with fewer than 25 connections, the fee will be $75.

(B) For systems with 25 - 99 connections, the fee will be $150.

(C) For a system with greater than or equal to 100 connections, the fee = $c^{0.75}$ X \$4.80, where "c" is the number of connections.

*(i)* The number of connections will be determined from data collected from the latest agency inspection report.

*(ii)* All nontransient noncommunity systems, state, federal, and other community water system installations determined by the commission to serve large populations through a few connections will have the number of connections for fee purposes determined by dividing the population served by a value of ten.

*(iii)* Examples of such installations include, but are not limited to, universities, children's homes, correctional facilities, and military facilities which generally do not bill customers for water service.

[~~Figure: 30 TAC §290.51(a)(3)~~]

(4) - (6) (No change.)

(b) (No change.)

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 September 27, 2001.

TRD-200105856

Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 239-6087

♦ ♦ ♦

# TITLE 34. PUBLIC FINANCE

## PART 3. TEACHER RETIREMENT SYSTEM OF TEXAS

### CHAPTER 25. MEMBERSHIP CREDIT

### SUBCHAPTER G. PURCHASE OF CREDIT FOR OUT-OF-STATE SERVICE

#### 34 TAC §25.85

The Teacher Retirement System of Texas (TRS) proposes amendments to §25.85 concerning purchase of out-of-state service credit. The amendments would increase from ten years to fifteen years the maximum amount of out-of-state service credit that may be purchased, subject to plan qualification requirements. The purpose of the amendments is to reflect changes in the law on how much out-of-state service credit may be purchased and to ensure that purchases are made consistently with plan qualification requirements.

Ronnie Jung, TRS Deputy Director, has determined that for each year of the first five-year period the rule is in effect there will be no fiscal implications to state or local governments as a result of enforcing or administering the rule.

Mr. Jung also has determined that for each year of the first five years the rule is in effect the public benefit anticipated will be that eligible members may purchase the maximum amount of out-of-state service credit specified by statute, to the extent consistent with plan qualification requirements. There will be no effect on small businesses. There are no anticipated economic costs to the persons who are required to comply with the rule as proposed.

Comments on the proposal may be submitted to Charles L. Dunlap, Executive Director, Teacher Retirement System of Texas, 1000 Red River, Austin, Texas 78701. Comments must be received no later than 30 days after the date the proposal is published in the *Texas Register*.

The amendments are proposed under Government Code, Chapter 825, §825.102, which authorizes the Board of Trustees of the Teacher Retirement System to adopt rules for eligibility of membership, the administration of the funds of the retirement system, and the transaction of business of the Board, and §825.506, which authorizes the Board to adopt rules necessary for the retirement system to be a qualified plan. The amendments also are proposed under Government Code, Chapter 823, §823.401, which authorizes the purchase of out-of-state service credit.

No other codes are affected by the proposal.

*§25.85. Amount of Out-of-State Service Which Can Be Purchased.*

(a) Credit is limited to one year of out-of-state service for each year in Texas.

(b) No out-of-state service can be used to compute any benefit for any person with less than 5 years service in Texas.

(c) Not more than 15[~~10~~] years out-of-state service can be purchased in accordance with Government Code, §823.401, and any purchase is subject to applicable plan qualification requirements, including applicable permissive service credit purchase restrictions under Government Code, §823.006 and/or the Internal Revenue Code of 1986, as amended from time to time.

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 October 1, 2001.

TRD-200105938
Charles L. Dunlap
Executive Director
Teacher Retirement System of Texas
Proposed date of adoption: November 16, 2001
For further information, please call: (512) 391-2115

♦ ♦ ♦

## SUBCHAPTER L. OTHER SPECIAL SERVICE CREDIT

### 34 TAC §25.162

The Teacher Retirement System of Texas (TRS) proposes amendments to §25.162 concerning the purchase of one year of service credit for accumulated state personal or sick leave. The section implements Government Code §823.403 as amended by the 74th Legislature, 1995. The proposed amendments are being simultaneously submitted for adoption on an emergency basis. §The proposed amendments delete inapplicable language relating to state and federal restrictions on certain permissive service credit purchases such as the requirement that a member be employed in a TRS-covered position at the date of the purchase of the credit. The proposed amendments also delete reference to Government Code §823.006 relating to the permissive service credit purchase restrictions associated with the purchase of nonqualified service, as it is not applicable. In addition, the proposal adds new language to clarify that federal plan qualification requirements and limits under the Internal Revenue Code do apply.

Ronnie Jung, Deputy Director has determined that for each year of the first five-year period the section is in effect, there will be no fiscal implications to state or local governments as a result of enforcing or administering the rule.

Mr. Jung has also determined that for each year of the first five years the amendments are in effect the public benefit anticipated is that an appropriate process will be in place to process participant requests for purchase of eligible service credit in accordance with applicable law. There will be no effect on small businesses. There are no anticipated economic costs to the public or the other persons who are required to comply with the amendments as proposed.

Comments on the proposal may be submitted to Charles L. Dunlap, Executive Director, 1000 Red River Street, Austin, Texas 78701. Comments must be received no later than 30 days after the date the proposal is published in the *Texas Register*.

The amendments are proposed under the Government Code, Chapter 825, §825.102, which authorizes the Board of Trustees of the Teacher Retirement System to adopt rules for eligibility for membership and the administration of the funds of the retirement system. The amendments are also proposed under Government Code, Chapter 823, §823.403(b), which requires the Board of Trustees to adopt the rules regarding an employer's certification of a member's accumulated personal or sick leave and under §823.403(d) which authorizes the Board of Trustees to adopt rates and tables recommended by the actuary. In addition, Government Code, Chapter 825, §825.506, authorizes the Board to adopt rules necessary for the retirement system to be a qualified plan. Other laws affected by this proposal: Government Code, Chapter 821, §821.001(7) and Insurance Code, Article 3.50-4, §2(10)(A)

*§25.162. State Personal or Sick Leave Credit.*

(a) Effective September 1, 2001, an eligible member may purchase one year of service credit in the Teacher Retirement System of Texas ("TRS")for accumulated state personal or sick leave in accordance with Government Code §823.403 and subject to approval of TRS and to any [~~applicable restrictions including~~] plan qualification requirements and limits under the Internal Revenue Code of 1986, as amended from time to time[~~such as permissive service credit purchase restrictions. Permissive service credit purchase restrictions may limit the purchase of non-qualified service as defined in Government Code §823.006 to an aggregate of five years~~].

(b) A member is eligible to purchase one year of service credit if the member retires from an employer defined by §821.001(7) of the Government Code[~~, is employed by such an employer at the date of purchase of the service credit,~~] and has at least 50 days or 400 hours of accumulated state personal or sick leave on the last day of employment before retirement. Not more than an aggregate of five days of unused state personal or sick leave may be accumulated per year. State personal and sick leave may be combined, if needed, for the purpose of calculating the necessary 50 days or 400 hours. No more than one year of service credit may be purchased even if more time has been accumulated.

(c) Credit purchased under this section may be used only for the purpose of calculating benefits and may not be used to determine eligibility for benefits or for retirement, including eligibility for Texas Public School Employees Group Insurance Program per Article 3.50-4, §2(10)(A) of the Insurance Code.

(d) To establish service credit under this section, an eligible member must submit an employer certification in the form and manner prescribed by TRS. Additionally, the eligible member must deposit with TRS, in the manner prescribed by TRS, the actuarial present value of the additional standard retirement annuity benefits that would be attributable to the conversion of the unused state personal or sick leave into the service credit, as described in subsection (e) of this section.

(e) To compute these amounts, TRS will use the State Personal or Sick Leave Conversion Factor Tables furnished by the TRS actuary of record Specifically, TRS will select the applicable conversion factor from the table based on the age of the member in full years and months at the effective date of retirement. To obtain the cost of the service credit, the conversion factor will be multiplied by the increase in the monthly standard retirement annuity resulting from the conversion of state personal or sick leave to an additional one year of service credit. The increase in the annuity will be determined using the standard retirement annuity without an adjustment for an optional service retirement annuity plan selected by the member because any optional plan selected by the member is required by §824.204(b) of the Government Code to be the actuarial equivalent of the member's standard retirement annuity.
Figure 1: 34 TAC §25.162(e) (No change.)

Figure 2: 34 TAC §25.162(e) (No change.)
Figure 3: 34 TAC §25.162(e) (No change.)

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 October 1, 2001.

TRD-200105939
Charles L. Dunlap
Executive Director
Teacher Retirement System of Texas
Proposed date of adoption: November 16, 2001
For further information, please call: (512) 391-2115

♦ ♦ ♦

# CHAPTER 29. BENEFITS

## SUBCHAPTER A. RETIREMENT

### 34 TAC §29.8

The Teacher Retirement System of Texas (TRS) proposes amendments to §29.8 concerning payment of benefits to designated beneficiaries under optional retirement payment plans. The amendments would change the description of the persons to whom optional retirement benefits may be paid after the death of a retiree by removing the language requiring that the beneficiary be named before retirement. The purpose of the amendments is to conform the rule to changes in the law, which in some situations permits a new designation of beneficiary after retirement. The purpose also is to correct minor grammatical errors.

Ronnie Jung, TRS Deputy Director, has determined that for each year of the first five-year period the rule is in effect there will be no fiscal implications to state or local governments as a result of enforcing or administering the rule.

Mr. Jung has also determined that for each year of the first five years the rule is in effect the public benefit anticipated will be that a retiree may designate a beneficiary for an optional service retirement payment plan after the time of retirement to the extent permitted by statute. There will be no effect on small businesses. There are no anticipated economic costs to the persons who are required to comply with the rule as proposed.

Comments on the proposal may be submitted to Charles L. Dunlap, Executive Director, Teacher Retirement System of Texas, 1000 Red River, Austin, Texas 78701. Comments must be received no later than 30 days after the date the proposal is published in the *Texas Register*.

The amendments are proposed under Government Code, Chapter 825, §825.102, which authorizes the Board of Trustees of the Teacher Retirement System to adopt rules for eligibility for membership, the administration of the funds of the retirement system, and the transaction of business of the Board. The amendments also are proposed under Chapter 824, subchapters B and C, which describe the designation of beneficiaries and the payment of service retirement benefits.

No other codes are affected by the proposal.

*§29.8. Retirement Payment Plans.*

(a) The standard annuity benefit is payable throughout life for service retirees or for the duration of the disability for disability retirees with at least 10 years of service, with payments ceasing the month following the death of the retired member. If the retired member did not receive annuity payments equal to his accumulated contributions, there shall be paid to his beneficiary an amount equal to the retired member's accumulated contributions less the total amount of retirement benefits paid to the retired member.

(b) An option which permits the retiree to reduce his own annuity with monthly benefits continuing to a beneficiary after his death may be selected in lieu of the standard annuity. The options are:

(1) a reduced allowance payable throughout life with the provision that upon the death of the retired member, the reduced allowance shall be continued throughout the life of, and paid to, the person designated as beneficiary of the optional annuity[~~named before retirement~~]. Upon the death of a retired member's beneficiary who was receiving an Option 1 annuity, if the total payment of benefits to the retired member and his beneficiary under this option was less than the accumulated contributions of the retired member, then the estate or heirs of the beneficiary shall be refunded an amount equal to the retired member's accumulated contributions less the total amount of Option 1 benefits which has been paid to both annuitants;

(2) a reduced allowance payment throughout life with the provision that, upon the death of the retired member, one-half of the reduced allowance shall be continued throughout the life of, and paid to, the person designated as beneficiary of the optional annuity[~~named before retirement~~]. Upon the death of a retired member's beneficiary who was receiving an Option 2 annuity, if the total payment of benefits to the retired member and his beneficiary under this option was less than the accumulated contributions of the retired member, then the estate or heirs of the beneficiary shall be refunded an amount equal to the retired member's accumulated contributions less the total amount of Option 2 benefits that[~~which~~] had been paid to both annuitants;

(3) a reduced allowance payable for guaranteed period of five years and as long thereafter as the retired member shall live;

(4) a reduced allowance payable for guaranteed period of 10 years and as long thereafter as the retired member shall live;

(5) a reduced allowance payable throughout life with the provision that upon the death of the retired member, three-fourths of the reduced allowance shall be continued throughout the life of, and paid to, the person designated as beneficiary of the optional annuity[~~named before retirement~~]. Upon the death of the retired member's beneficiary who was receiving an Option 5 annuity, if the total payment of benefits to the retired member and his beneficiary under this option was less than the accumulated contributions of the retired member, then the estate or heirs of the beneficiary shall be refunded an amount equal to the retired member's accumulated contributions less the total amount of Option 5 benefits that[~~which~~] had been paid to both annuitants.

(c) For Option 1, Option 2, and Option 5, if the beneficiary predeceases the retiree, the retiree's annuity will be increased (pop-up) to the standard service annuity that the retiree would otherwise be entitled to receive if the retiree had not selected Option 1 or 2 or 5 but had selected the standard annuity. The standard annuity shall be adjusted by the early age reduction factor in effect at the time of retirement if the member retired under the early age service retirement provisions. The standard annuity shall also be adjusted for any post-retirement[~~post retirement~~] increases in retirement benefits authorized by law for the standard annuity after the date of retirement.

(1) The increased annuity will begin with the first monthly payment that[~~which~~] should have been made to the retiree following the month in which the beneficiary's death occurs.

(2) The retiree shall promptly notify the TRS of the death of the beneficiary and submit a certified copy of the beneficiary's death certificate or other adequate proof of death to TRS. In the event that the retiree fails to notify TRS promptly of the death of the beneficiary, TRS shall continue to pay the reduced annuity to the retiree until properly notified of the beneficiary's death. Any payment for past months in which the retiree could have been receiving the standard annuity shall be made in a lump sum with the first monthly payment after the month in which notice is received. No interest shall be paid with any lump sum payment.

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 October 1, 2001.

TRD-200105937
Charles L. Dunlap
Executive Director
Teacher Retirement System of Texas
Proposed date of adoption: November 16, 2001
For further information, please call: (512) 391-2115

♦ ♦ ♦

# CHAPTER 41. INSURANCE PROGRAMS
# SUBCHAPTER C. TEXAS SCHOOL EMPLOYEES GROUP HEALTH

## 34 TAC §41.30

The Teacher Retirement System of Texas (TRS) proposes new §41.30, concerning participation in the Texas School Employees Uniform Group Health Coverage Act (Act) by school districts, other educational districts, charter schools, and regional education service centers. The new section sets forth the manner, form, and effect of elections to opt in or out of participation in the coverage under the Act. The section includes provisions regarding the deadlines for certain entities to opt in or out of participation and the effect of such elections. The proposed new rule was previously adopted on an emergency basis.

The new section is necessary for the proper and efficient administration of the notification, election, and participation requirements of Insurance Code article 3.50-7.

Ronnie Jung, TRS Deputy Director, has determined that for each year of the first five-year period the rule is in effect there will be no fiscal implications to state or local governments as a result of enforcing or administering the rule.

Mr. Jung also has determined that for each year of the first five years the rule is in effect the public benefit anticipated as a result of the section will be the orderly election of participation in the school and educational employees group coverage programs. There will be no effect on small businesses. There are no anticipated economic costs to the persons who are required to comply with the rule as proposed.

Comments on the proposal may be submitted to Charles L. Dunlap, Executive Director, Teacher Retirement System of Texas, 1000 Red River, Austin, Texas 78701. Comments must be received no later than 30 days after the date the proposal is published in the *Texas Register*.

The new section is proposed under Insurance Code article 3.50-7, which gives TRS authority to adopt rules as necessary to implement and administer the uniform group coverage program established by the Act. The new section also is proposed under Government Code, Chapter 825, §825.102, which authorizes the Board of Trustees of the Teacher Retirement System to adopt rules for the transaction of business of the Board.

No other codes are affected by the proposal.

*§41.30. Participation in the Texas School Employees Uniform Group Health Coverage Act by School Districts, Other Educational Districts, Charter Schools, and Regional Education Service Centers.*

(a) Manner, form and effect of election. All elections to opt in or opt out of participation in the uniform group coverage under the Texas School Employees Uniform Group Health Coverage Act (the "Act") pursuant to the provisions of Insurance Code, Article 3.50-7, §§5 or 6, as added by the 77th Legislature, 2001 in House Bill 3343 shall be in writing, on an election form prescribed by the Teacher Retirement System of Texas ("TRS"), and received by TRS no later than 5:00 p.m. on or before the applicable election deadline date specified in this section. An election form otherwise valid received by facsimile before the applicable deadline is acceptable if TRS receives the original, signed election form within seven calendar days after the applicable deadline. An incomplete or unsigned form will not be deemed received by TRS for purposes of determining whether a valid election has been exercised. A valid election filed with TRS is irrevocable once the election deadline passes, unless TRS is authorized to extend a deadline and does so by resolution of the TRS Board of Trustees. Entities electing to participate in the uniform group coverage under the Act may not discontinue participation unless authorized by Insurance Code, Article 3.50-7, and by appropriate rule or resolution adopted by the TRS Board of Trustees. Entities opting out of participation in the uniform group coverage under the Act have no further opportunity to elect to participate except as authorized by Insurance Code, Article 3.50-7, and by appropriate rule or resolution adopted by the TRS Board of Trustees. If an entity has an option to opt in and thereby participate in the coverage under the Act, a failure to properly or timely file the election form shall have the effect of the entity electing not to participate. Likewise, if an entity has an option to opt out and thereby not participate in the coverage under the Act, a failure to properly or timely file the election form shall have the effect of the entity electing to participate.

(b) School districts with 500 or fewer employees. Pursuant to Insurance Code, Article 3.50-7 §5(a), school districts with 500 or fewer employees as of January 1, 2001 are required to participate effective September 1, 2002 in the uniform group coverage under the Act, except that certain of these school districts may delay or opt out of participation by specified election deadlines as provided in paragraphs (1) - (3) of this subsection. On or before September 1, 2001, all school districts must furnish information and verifications requested by TRS on the form prescribed by TRS, regardless of whether an election to delay or opt out of participation applies to such district or is being exercised by such school district.

(1) Pursuant to Insurance Code, Article 3.50-7 §5(g), a school district with 500 or fewer employees as of January 1, 2001 that, on January 1, 2001, was individually self-funded for the provision of health care coverage to its employees may elect to opt out of the mandatory participation in coverage effective September 1, 2002, by filing its election form with TRS on or before September 1, 2001.

(2) Pursuant to Insurance Code, Article 3.50-7 §5(e), a school district with 500 or fewer employees as of January 1, 2001 that was a member on January 1, 2001 of a risk pool established under the authority of Local Government Code, Chapter 172, may opt out of the mandatory participation in coverage effective September 1, 2002 by filing its election form with TRS on or before September 1, 2001 and electing thereby to continue in the risk pool that the district participated in on January 1, 2001.

(3) Pursuant to Insurance Code, Article 3.50-7 §5(h), a school district with 500 or fewer employees as of January 1, 2001 that is a party to a contract for the provision of health insurance coverage to the employees of the district that is in effect on September 1, 2002 may delay mandatory participation in coverage effective September 1, 2002, by filing its election with TRS on or before September 1, 2001. At the time of such election, such a school district must provide the expiration date of the contract to TRS and shall begin mandatory participation in the uniform group coverage under the Act on the first day of the month immediately following the month in which termination or expiration of the contract occurs.

(c) School districts with 501 or more employees. Pursuant to Insurance Code, Article 3.50-7 §5(b), school districts with 501 or more employees on January 1, 2001 may elect to participate in the uniform group coverage under the Act, with coverage effective September 1, 2005. January 1, 2005 is the deadline for such a school district to file its election with TRS to participate in the uniform group coverage under the Act. Notwithstanding the preceding two sentences, school districts with 501 or more employees may elect to participate prior to September 1, 2005 as set forth in paragraphs (1) and (2) of this subsection. All school districts must furnish information and verifications to TRS on or before September 30, 2001 on a form prescribed by TRS, regardless of whether an election to participate prior to September 1, 2005 applies to such district or is being exercised by such district.

(1) Pursuant to Insurance Code, Article 3.50-7 §5(b-1), school districts may elect to participate prior to September 1, 2005 if TRS determines that participation prior to September 1, 2005 by school districts with more than 500 employees on January 1, 2001 would be administratively feasible and cost-effective. TRS will set the election deadline from time to time by rule or resolution of the TRS Board of Trustees, as applicable.

(2) Pursuant to Insurance Code, Article 3.50-7 §5(a-1), September 30, 2001 is the deadline for a school district with at least 501 but not more than 1,000 employees on January 1, 2001 to file its election to commence participation effective September 1, 2002. A school district that does not elect to opt in early and participate effective September 1, 2002, may elect in the future to opt in if otherwise permitted under this subsection.

(d) Educational districts. Pursuant to Insurance Code, Article 3.50-7 §5(i), educational districts whose employees are members of TRS are required to participate effective September 1, 2002 in the uniform group coverage under the Act, except that educational districts with 500 or fewer employees on January 1, 2001 may opt out of participation. September 1, 2001 is the deadline for such an educational district to file its election with TRS to opt out of participation in the uniform group coverage under the Act. Regardless of whether an educational district elects to opt out of participation and file an election form, information and verifications requested by TRS must be furnished by all educational districts on the form prescribed by TRS and returned to TRS on or before September 1, 2001.

(e) Charter schools. Pursuant to Insurance Code, Article 3.50-7 §6, an open-enrollment charter school established under Education Code, Chapter 12, Subchapter D, ("charter school") may elect to participate in the uniform group coverage under the Act. Only an eligible charter school may elect to participate. A charter school that received funding in accordance with Education Code, Chapter 12, prior to June 1, 2001, must furnish information and verifications requested by TRS, on the form prescribed by TRS, on or before September 1, 2001, whether or not the charter school elects to participate in the uniform group coverage.

(1) Pursuant to Insurance Code, Article 3.50-7 §6(a), to be eligible, a charter school must agree to inspection of all records of the school relating to its participation in the uniform group coverage under the Act by TRS, by the administering firm as defined in Insurance Code, Article 3.50-7 §2(1), by the commissioner of education, or by a designee of any of those entities, and further must agree to have its accounts relating to participation in the uniform group coverage under the Act annually audited by a certified public accountant at the school's expense. The agreement of the charter school shall be evidenced in writing and shall constitute a part of the election form prescribed by TRS pursuant to subsection (a) of this section.

(2) Pursuant to Insurance Code, Article 3.50-7 §6(b), an eligible charter school shall elect to participate in the uniform group coverage under the Act effective September 1, 2002, by filing its election form with TRS on or before September 1, 2001 if the charter school received any state funding in accordance with Education Code, Chapter 12, prior to June 1, 2001.

(3) Pursuant to Insurance Code, Article 3.50-7 §6(b), an eligible charter school that did not receive any state funding in accordance with Education Code, Chapter 12, prior to June 1, 2001, shall elect, if at all, to participate in the uniform group coverage under the Act by filing its election form with TRS on or before the later of September 1, 2001 or the ninetieth calendar day following the date the Texas Education Agency authorized the Comptroller to issue the first payment of state funds to such charter school. Participation in coverage for such eligible charter school shall be effective on the later of September 1, 2002 or the first day of the month following the month in which a valid election to participate is filed with TRS.

(f) Regional education service centers. Pursuant to Insurance Code, Article 3.50-7 §5(a), each regional education service center established under Education Code, Chapter 8, is required to participate effective September 1, 2002 in the uniform group coverage under the Act. Information and verifications requested by TRS must be furnished by each regional education service center on the form prescribed by TRS and returned to TRS on or before September 1, 2001.

(g) This section becomes effective at the earliest date permitted by law, but not later than September 1, 2001.

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 October 1, 2001.

TRD-200105936
Charles L. Dunlap
Executive Director
Teacher Retirement System of Texas
Proposed date of adoption: November 16, 2001
For further information, please call: (512) 391-2115

♦ ♦ ♦

## TITLE 37. PUBLIC SAFETY AND CORRECTIONS

## PART 7. TEXAS COMMISSION ON LAW ENFORCEMENT OFFICER STANDARDS AND EDUCATION

## CHAPTER 211. ADMINISTRATION

### 37 TAC §211.1

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code, §211.1, concerning definitions. For clarification purposes, the proposed amendment adds a definition for the term "training cycle". The amendment also proposes the renumbering of the paragraphs of this section as well as a change to the effective date in subsection (b) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr. Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

The amendment is proposed under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by the proposed amendment: Texas Occupations Code Annotated, Chapter 1701, §1701.151--General Powers.

*§211.1. Definitions.*

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

(1) - (48) (No change.)

[~~(49) Texas peace officer--For the purposes of eligibility for the Texas Peace Officers' Memorial, an individual who had been elected, employed, or appointed as a peace officer under Texas law; an individual appointed under Texas law as a reserve peace officer; a commissioned deputy game warden, or a corrections officer in a municipal, county or state penal institution, or any other officer authorized by Texas law.~~]

<u>(49)</u> [~~(50)~~] Telecommunicator--A dispatcher or other emergency communications specialist appointed under or governed by the provisions of the Occupations Code, Chapter 1701.

<u>(50) Texas peace officer--For the purposes of eligibility for the Texas Peace Officers' Memorial, an individual who had been elected, employed, or appointed as a peace officer under Texas law; an individual appointed under Texas law as a reserve peace officer who; a commissioned deputy game warden, or a corrections officer in a municipal, county or state penal institution, or any other officer authorized by Texas law.</u>

(51) (No change.)

<u>(52) Training cycle--One period from the set of contiguous 48-month periods that begins on September 1, 2001. Each training cycle is composed of two contiguous 24-month units.</u>

<u>(53)</u> [~~(52)~~] Training hours--Actual classroom or distance education hours. One college semester hour equates to 20 training hours.

<u>(54)</u> [~~(53)~~] Verification (verified)--The confirmation of the correctness, truth, or authenticity of a document, report, or information by sworn affidavit, oath, or deposition.

(b) The effective date of this section is <u>March 1, 2002</u> [~~August 1, 2001~~].

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 October 1, 2001.

TRD-200105919

Edward T. Laine

Chief, Professional Standards and Administrative Operations

Texas Commission on Law Enforcement Officer Standards and Education

Proposed date of adoption: March 1, 2002

For further information, please call: (512) 936-7700

♦ ♦ ♦

### 37 TAC §211.27

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code, §211.27, concerning the reporting responsibilities of individuals. For consistency purposes, changes were made in subsections (a) and (c) of this section. The language, which previously read, "a person who holds a commission license or certificate," was deleted and was replaced by the term "licensee". The language is being provided to clarify that the Commission takes administrative action against licensees, not certificates that they hold. A proposed change was also made to the effective date in subsection (d) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr. Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

The amendment is proposed under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by the proposed amendment: Texas Occupations Code Annotated, Chapter 1701, §1701.151 - General Powers.

*§211.27. Reporting Responsibilities of Individuals.*

(a) When a licensee [~~person who holds a commission license or certificate~~] is arrested, charged, or indicted for a criminal offense above the grade of Class C misdemeanor or for any Class C misdemeanor involving the duties and responsibilities of office or family violence, that person must report such fact to the commission in writing within 30 days, including the name of the arresting agency, the style, court, and cause number of the charge or indictment, if any, and the address to which notice of any commission action will be mailed.

(b) (No change.)

(c) A licensee [~~license holder~~] must report any name change to the commission within 30 days.

(d) The effective date of this section is March 1, 2002 [~~2001~~].

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 October 1, 2001.

TRD-200105920
Edward T. Laine
Chief, Professional Standards and Administrative Operations
Texas Commission on Law Enforcement Officer Standards and Education
Proposed date of adoption: March 1, 2002
For further information, please call: (512) 936-7700

♦ ♦ ♦

# CHAPTER 215. TRAINING AND EDUCATIONAL PROVIDERS AND RELATED MATTERS

## 37 TAC §215.3

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code, §215.3, concerning academy licensing. For consistency purposes, changes were made to some of the terms used in a number of the subsections. The subsections that were affected were (a)(3) and (6); (b)(5), (7) and (8)(A) - (C); (d); (e)(1) and (3); (h)(2) of this section; and a change was made in the effective date in subsection (j) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr. Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

The amendment is proposed under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by the proposed amendment: Texas Occupations Code Annotated, Chapter 1701, §1701.151--General Powers.

*§215.3. Academy Licensing.*

(a) The commission may issue an academy license to an academy that is operated by or for the state or any political subdivision of the state for the specific purpose of providing law enforcement, corrections, telecommunications, and/or other law enforcement related training. In order for a license to be issued, a comprehensive training needs assessment must be submitted to the commission, justifying the need for an additional academy in the regional planning commission or council of governments area in which the proposed academy will be located. The needs assessment must include as a minimum:

(1) - (2) (No change.)

(3) a description of existing law enforcement training programs in the proposed service area and documentation [~~evidence~~] justifying the need for an additional academy;

(4) - (5) (No change.)

(6) proof of notification by certified mail to all licensed academies within the regional planning commission or council of governments area of their intent to apply for an academy license and what specific training needs the applicant intends to meet [~~are not currently being met within the region~~].

(b) If the commission determines that the training needs assessment justifies an additional academy in the area, and before an academy license may be issued, the proposed academy must pass an inspection of its facilities and instructional materials and must submit for commission approval:

(1) - (4) (No change.)

(5) documentation [~~evidence~~] that an advisory board has already been appointed as provided by the Occupations Code, Chapter 1701.252, including a resume for each board member;

(6) (No change.)

(7) the name, social security number and resume of the proposed training [~~academy~~] coordinator and any academy staff instructors, and a list of instructors who are scheduled to teach the submitted proposed course schedule;

(8) documentation [~~evidence~~] that the academy will be[~~,~~] based on at least one [~~the characteristics~~] of the following sponsoring organizations; [~~organization at least one of the following:~~]

(A) [~~an agency academy, conducted by~~] a law enforcement agency that has at least 50 full-time paid peace officers and/or county jailers under current appointment;

(B) [~~a college academy, conducted by~~] an institution recognized by the Texas Higher Education Coordinating Board; or

(C) [~~a regional academy, conducted or sponsored by~~] a regional planning commission or council of governments (COG) board;

*(i) - (ii)* (No change.)

(9) - (11) (No change.)

(c) The pre-licensing inspection of the academy's facilities and instructional materials shall be conducted by commission staff, or by a team of academy coordinators as appointed by the executive director. An academy must have and maintain:

(1) - (4) (No change.)

(5) a proprietary interest in, or a written contract providing for an all-weather accessible firing range suitable for the course of fire required in the current basic peace officer course with safety rules clearly posted, adequate restrooms, secure storage and first aid equipment while on the premises; [~~and~~]

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

(d) The chief administrator or head of the organization exercising administrative control of the proposed academy and the proposed training [~~academy~~] coordinator must appear before the commissioners to respond to any questions prior to any action being taken on the application.

(e) Once an academy license is issued, the chief administrator of the academy or the sponsoring agency must report in writing to the commission within 30 days:

(1) any change in training [~~academy~~] coordinator;

(2) (No change.)

(3) any rule violation by it or by its training [~~academy~~] coordinator, instructors, or advisory board;

(4) - (5) (No change.)

(f) - (g) (No change.)

(h) The commission may revoke an academy license if:

(1) (No change.)

(2) its training [~~academy~~] coordinator intentionally or knowingly submits a falsified document or a false written statement or representation to the commission; or

(3) (No change.)

(i) (No change.)

(j) The effective date of this section is March 1, 2002 [~~2001~~].

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 October 1, 2001.

TRD-200105921
Edward T. Laine
Chief, Professional Standards and Administrative Operations
Texas Commission on Law Enforcement Officer Standards and Education
Proposed date of adoption: March 1, 2002
For further information, please call: (512) 936-7700

♦ ♦ ♦

**37 TAC §215.5**

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code, §215.5, concerning contractual training. For clarification purposes the term "requesting party" was changed to the term "applicant" in subsection (e)(1)(A) of this section. The only other proposed change to this section was to the effective date in subsection (i) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr. Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

The amendment is proposed under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by the proposed amendment: Texas Occupations Code Annotated, Chapter 1701, §1701.151--General Powers.

*§215.5. Contractual Training.*

(a) - (d) (No change.)

(e) The contractual training provider must:

(1) provide a comprehensive needs assessment to the executive director justifying the need for a contract. The needs assessment must include at a minimum:

(A) the names of the licensed academies located in the council of governments or regional planning commission area of the applicant [~~requesting party~~];

(B) - (D) (No change.)

(2) - (14) (No change.)

(f) - (h) (No change.)

(i) The effective date of this section is March 1, 2002 [~~2001~~].

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 October 1, 2001.

TRD-200105922
Edward T. Laine
Chief, Professional Standards and Administrative Operations
Texas Commission on Law Enforcement Officer Standards and Education
Proposed date of adoption: March 1, 2002
For further information, please call: (512) 936-7700

♦ ♦ ♦

**37 TAC §215.15**

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code, §215.15, concerning enrollment standards and training credit. Additional language provides clarification regarding the Commission's role, that training credit will be granted for courses conducted by a licensed academy as provided in the Commission's rules. In addition, the language provided in subsection (d)(1) - (3) of this section explains what records an academy must have on file for individuals who enroll in any basic peace officer training program which provides instruction in defensive tactics, arrest procedures, firearms, or use of a motor vehicle for law enforcement purposes. In addition, the language provided in subsection (e)(4) of this section is intended to minimize incidents where licensees obtain training credit by deceitful means. The other proposed changes in §215.15 include the renumbering of the subsections and a proposed change to the effective date in subsection (g) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr. Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

The amendment is proposed under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by the proposed amendment: Texas Occupations Code Annotated, Chapter 1701, §1701.151--General Powers.

*§215.15. Enrollment Standards and Training Credit.*

(a) In order for a person to enroll in any law enforcement training program which provides instruction in defensive tactics, arrest procedures, firearms, or use of a motor vehicle for law enforcement purposes, the academy must have on file;

(1) (No change.)

(2) if the person is not licensed by the commission, documentation that the person:

(A) has never been [~~nor~~ ~~currently~~] on court-ordered community supervision or probation for any criminal offense above the grade of a Class B misdemeanor or a Class B misdemeanor within the last ten years from the date of the court order;

(B) - (F) (No change.)

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

(d) In order for a person to enroll in any basic peace officer training program which provides instruction in defensive tactics, arrest procedures, firearms, or use of a motor vehicle for law enforcement purposes, the academy must have on file;

(1) a high school diploma;

(2) a high school equivalency certificate and has a completed at least 12 hours at an institution of higher education with at least a 2.0 grade point average on a 4.0 scale; or

(3) an honorable discharge from the armed forces of the United States after at least 24-months of active duty service;

(e) [~~(d)~~] The commission will award training credit for any course conducted by a licensed academy as provided by commission rules unless:

(1) the course is not taught as required by commission rules and the advisory board;

(2) the training is not related to a commission license; [~~or~~]

(3) the advisory board, the academy, the academy coordinator, the course coordinator, or the instructor substantially failed to discharge any responsibility required by commission rule; or [~~.~~]

(4) the credit was claimed by deceitful means.

(f) [~~(e)~~] The enrollment standards established in this section do not preclude the academy licensee from establishing additional requirements or standards for enrollment in law enforcement training programs.

(g) [~~(f)~~] The effective date of this section is March 1, 2002 [~~2001~~].

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 October 1, 2001.

TRD-200105923
Edward T. Laine
Chief, Professional Standards and Administrative Operations
Texas Commission on Law Enforcement Officer Standards and Education
Proposed date of adoption: March 1, 2002
For further information, please call: (512) 936-7700

♦ ♦ ♦

**37 TAC §215.17**

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code, §215.17, concerning distance education. Additional language provided in subsection (d) of this section provides clarification regarding distance education courses and the Commission's role. In addition, the added language provided in this subsection is intended to minimize incidents where licensees obtain distance education training credit by deceitful means. The only other proposed change in §215.17 includes a change to the effective date in subsection (f) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr. Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

The amendment is proposed under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by the proposed amendment: Texas Occupations Code Annotated, Chapter 1701, §1701.151--General Powers.

*§215.17. Distance Education.*

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

(d) To receive credit for a distance education course, the student must, without the use of deceitful means, complete each required unit, and receive a passing grade on any examination, course work, or evaluation required by the lesson guide or learning objectives.

(e) (No change.)

(f) The effective date of this section is March 1, 2002 [~~2001~~].

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 October 1, 2001.

TRD-200105924

Edward T. Laine

Chief, Professional Standards and Administrative Operations

Texas Commission on Law Enforcement Officer Standards and Education

Proposed date of adoption: March 1, 2002

For further information, please call: (512) 936-7700

♦ ♦ ♦

# CHAPTER 217. LICENSING REQUIREMENTS

## 37 TAC §217.9

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes to adopt an amendment to Title 37, Texas Administrative Code §217.9, concerning continuing education credit for licensees. In subsection (b) of this section the term, "shall" was deleted and the term "may" was substituted for clarification and consistency with the Commission's rules. In subsection (b)(5) of this section, the proposed amendment clarifies that the Commission may refuse credit for more than one presentation of a course by an instructor, per training cycle. The proposed amendment gives the Commission authority to take administrative action against licensees that claim credit in instances where credit was obtained by deceitful means. Additional language in subsection (b)(6) of this section, also serves to clarify that the Commission may refuse credit for the continuing education course(s) if the course(s) is obtained by deceitful means. The amendment also proposes a change to the effective date in subsection (d) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr. Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

This amendment is proposed under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by this proposed rule: Texas Occupations Code Annotated, Chapter 1701, §1701.151 - General Powers.

*§217.9. Continuing Education Credit for Licensees.*

(a) A continuing education course is any training course that is approved by the commission, specifically:

(1) legislatively required continuing education curricula and learning objectives developed by the commission:

(2) training in excess of basic licensing course requirements;

(3) training courses consistent with assigned duties; or

(4) training not included in a basic licensing course.

(b) The commission may [~~shall~~] refuse credit for:

(1) a course which does not contain a final examination or other skills test, if appropriate, as determined by the training provider;

(2) annual firearms proficiency;

(3) an out of state course not approved by that state's POST;

(4) training that fails to meet any commission established length and published learning objectives; [~~or~~]

(5) an instructor claiming credit for a basic licensing course or more than one presentation of a non-licensing course by an instructor, per 24 month unit of a training cycle; or [~~any preparation and presentation time by an instructor for a commission developed course.~~]

(6) course(s) claimed by deceitful means.

(c) The training provider or agency must report to the commission and keep on file in a format readily accessible to the commission, a copy of all continuing education course training reports.

(d) The effective date of this section is March 1, 2002. [~~2001.~~]

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 October 1, 2001.

TRD-200105927

Edward T. Laine

Chief, Professional Standards and Administrative Operations

Texas Commission on Law Enforcement Officer Standards and Education

Proposed date of adoption: March 1, 2002

For further information, please call: (512) 936-7700

♦ ♦ ♦

**37 TAC §217.11**

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §217.11, concerning legislatively required continuing education for licensees. Proposed amendments to this section clarify that the Commission will track the legislatively required courses taken and completed by licensees every four years versus every two years. In subsections (a), (b) and (e) of this section language was added for clarification purposes. In subsection (h) of this section language was added to clarify when the commission may discipline an individual for failure to complete 40 hours of training in either or both of the 24 month units within a training cycle. In subsection (j) of this section language was added to clarify that individuals licensed as peace officers shall attend a course, developed by the commission, on asset forfeiture no later than September 1, 2002. In subsection (k) of this section, language was added to clarify that individuals licensed as peace officers shall attend a course, developed by the commission, on racial profiling no later than September 1, 2003. In subsection (l) of this section, language was added to clarify that all peace officers must meet the continuing education requirements except where exempt by law. This rule is written to conform with continuing education requirements for peace officers as set forth by the Legislature in the 2001 session. The only other proposed amendment was to the effective date in subsection (m) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr. Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

This amendment is proposed under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by this proposed rule: Texas Occupations Code Annotated, Chapter 1701, §1701.151 - General Powers.

*§217.11. Legislatively Required Continuing Education for Licensees.*

(a) Each agency that appoints or employs peace officers, reserve law enforcement officers, jailers, or public security officers shall provide each peace officer, reserve law enforcement officer, jailer, or public security officer it appoints or employs a continuing education program at least once every 24 month unit of a [~~current~~] training cycle.

(b) The legislatively required continuing education program for individuals licensed as peace officers shall consist of 40 hours of training every 24 month unit of a training cycle. [~~The program shall contain no more than 20 hours of curricula and learning objectives developed by the commission. The remaining hours may consist of additional objectives and materials selected or developed by the appointing or employing agency. The additional topic or topics selected by the agency should be consistent with the peace officer's assigned duties.~~] This rule does not limit the number of hours of continuing education an agency may provide to each peace officer, reserve law enforcement officer, jailer, or public security officer it appoints or employs.

(c) Part of the [~~of~~] legislatively required peace officer training must include the curricula and learning objectives developed by the commission, to include:

(1) civil rights, racial sensitivity, and cultural diversity during each current training cycle;

(2) the recognition and documentation of cases that involve child abuse or neglect, family violence, sexual assault, issues concerning sex offender characteristics during each current training cycle. If an agency chief administrator determines these subjects to be inconsistent with the peace officer's assigned duties, the chief administrator may substitute other training determined to be consistent with the officer's assigned duties and report the substitution to the commission; and

(3) supervision issues for each peace officer appointed to their first supervisory position, this training must be completed within 24 months following the date of appointment as a supervisor.

(d) Individuals licensed as reserve law enforcement officers, jailers, or public security officers shall meet the requirements in subsection (c)(1) of this section.

(e) Each constable and deputy constable shall also complete a 20 hour course of training in civil process during each current training cycle. The commission may waive the requirement for civil process training if the constable submits a written request for [~~requests~~] a waiver, [~~by written certification,~~] because of hardship and the commission determines that a hardship exists.

(f) The commission shall provide notice to agencies and licensees of impending non-compliance with the legislatively required continuing education. Such notice will be provided not later than six months prior to the expiration of the current training cycle.

(g) The commission may suspend or deny renewal of a license for failure to complete the legislatively required continuing education program at least once every training cycle.

(h) The commission may take action against a licensee for failure to complete the required training in either or both of the 24 month units within a training cycle.

(i) [~~(h) All individuals who are licensed and reported to the commission as appointed or employed by an agency~~] Individuals licensed as peace officers shall complete the legislatively required continuing education program required under this section beginning in the first complete 24 month unit [~~two year period~~] immediately following the date of licensing.

(j) Individuals licensed as peace officers shall attend a course, developed by the commission, on asset forfeiture no later than September 1, 2002.

(k) Individuals licensed as peace officers shall attend a course, developed by the commission, on racial profiling no later than September 1, 2003.

(l) All peace officers must meet all continuing education requirements except where exempt by law.

(m) [~~(i)~~] The effective date of this section is March 1, 2002. [~~2001.~~]

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 October 1, 2001.

TRD-200105928

Edward T. Laine

Chief, Professional Standards and Administrative Operations

Texas Commission on Law Enforcement Officer Standards and Education

Proposed date of adoption: March 1, 2002

For further information, please call: (512) 936-7700

♦ ♦ ♦

## 37 TAC §217.17

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §217.17, concerning active license renewals. The proposed amendment to this subsection clarifies that the Commission will track the legislatively required courses taken and completed by licensees every four years versus every two years and that active licensees who have met the current legislatively required continuing education courses will have their license(s) automatically renewed on the last day of the training cycle. The amendments to subsection (c) and (d) of this section propose changes to the term reactivation and the term reinstated. These terms are being substituted by the terms reinstatement in subsection (c) and (d) of this section. A change is also being proposed to the effective date in subsection (e) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr. Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

This amendment is proposed under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by this proposed rule: Texas Occupations Code Annotated, Chapter 1701, §1701.151 - General Powers.

*§217.17. Active License Renewal.*

(a) Active licensees who have met the current legislatively required continuing education will have their license(s) automatically renewed on the last day of the training cycle. [~~August 31 of each odd numbered year.~~]

(b) The executive director shall notify in writing each active licensee who is in non-compliance with the current legislatively required continuing education at least 90 days prior to expiration. The notice shall be mailed to the licensee and to the licensee's last appointing agency, if any. The notice shall inform the licensee that the license will expire if the licensee does not meet the current legislatively required continuing education by the expiration date. The notice shall also inform the licensee of his or her opportunity to have the license reinstated.

(c) In order for an expired license to be reinstated, the licensee must meet the reinstatement [~~reactivation~~]requirements.

(d) The time between expiration and reinstatement [~~reinstated~~] of a license is not eligible to be used to meet any requirements for proficiency certification or service time.

(e) The effective date of this section is March 1, 2002. [~~2001.~~]

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 October 1, 2001.

TRD-200105929

Edward T. Laine

Chief, Professional Standards and Administrative Operations

Texas Commission on Law Enforcement Officer Standards and Education

Proposed date of adoption: March 1, 2002

For further information, please call: (512) 936-7700

♦ ♦ ♦

## 37 TAC §217.19

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §217.19, concerning reactivation of a license. The proposed amendment to this subsection clarifies the process that will be used by the Commission to allow individuals to maintain an active license status by completing the legislatively required continuing education. Subsection (f) of this section also clarifies the process that will be used for any jailer license issued after March 1, 2001. Jailers will be required to retest if out more than 2 years effective March 1, 2001. The amendment also proposed a change to the effective date in subsection (h) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr. Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

This amendment is proposed under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by this proposed rule: Texas Occupations Code Annotated, Chapter 1701, §1701.151 - General Powers.

*§217.19. Reactivation of a License.*

(a) The commission will place all licenses in an inactive status when the licensee has neither[~~not~~] been reported to the commission as appointed for more than two years after:

(1) the last report of termination,[~~;~~] or

(2) the date of last reactivation; nor[~~.~~]

(3) met all the continuing education requirements.

(b) Individuals with basic licensure training over two years old must meet the requirements of §217.19 (f) and (g) before they may be appointed.

(c) Individuals with basic licensure examination results over two years old must meet the requirements of §217.19 (f) and (g) before they may be appointed.

(d) The holder of an inactive license is unlicensed for purposes of these sections and the Occupations Code, Chapter 1701.

(e) This section includes any permanent peace officer qualification certificate with an effective date before September 1, 1981.

(f) This section includes any jailer licenses issued after March 1, 2001.

(g) [~~(f)~~]Before individuals with inactive licenses may be appointed they must:

(1) meet the current licensing standards, with successful completion of a [~~prior~~] basic licensing course current at the time of initial licensure; fulfilling [ ~~the current licensing course~~] this requirement; [~~and~~]

(2) successfully complete the legislatively required continuing education for the current training cycle.

[~~(g) Once an individual has~~]:

[~~(1) met the current standards; and~~]

(3) [~~(2)~~] make [~~made~~] application[~~,~~] and submit any required fee(s) for an endorsement in the format currently prescribed by the commission; [~~, submitted any required fee(s); and~~]

(4) [~~(3)~~] obtain an endorsement, issued by the commission, giving the individual; and [~~upon the approval of the application, the commission will issue the holder of an inactive license an endorsement of eligibility to take the required licensing examination. This endorsement of eligibility will allow the applicant to take the examination three times. If failed three times, the applicant may not be issued another endorsement of eligibility until successful completion of the current licensure course.~~]

(5) pass the licensing examination for the license to be reactivated. If failed three times, the applicant may not be issued another endorsement of eligibility until successful completion of the current basic licensure course.

(h) The effective date of this section is March 1, 2002. [~~August 1, 2001.~~]

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 October 1, 2001.

TRD-200105930
Edward T. Laine
Chief, Professional Standards and Administrative Operations
Texas Commission on Law Enforcement Officer Standards and Education
Proposed date of adoption: March 1, 2002
For further information, please call: (512) 936-7700

♦ ♦ ♦

## CHAPTER 221. PROFICIENCY CERTIFICATES AND OTHER POST-BASIC LICENSES

### 37 TAC §221.1

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §221.1 concerning proficiency certificate requirements. The proposed amendment to this subsection clarifies that an active licensee, who is not commissioned, will still be able to accrue certificates. Currently, a active licensee cannot earn certificates if not commissioned. The amendment also proposes a change to the effective date in subsection (f) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

This new section is proposed for amendment under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by this proposed rule: Texas Occupations Code Annotated, Chapter 1701, §1701.151 - General Powers.

*§221.1. Proficiency Certificate Requirements.*

(a) To qualify for proficiency certificates, applicants must meet all the following proficiency requirements:

(1) submit any required application currently prescribed by the commission, requested documentation, and any required fee;

(2) have an active license or appointment [~~be currently commissioned or appointed as a peace officer, reserve, jailer, or a telecommunicator~~] for the corresponding certificate (not a requirement for Mental Health Officer Proficiency, Homeowners Insurance Inspector Proficiency, Firearms Instructor Proficiency, Firearms Proficiency for Community Supervision Officers, or Instructor Proficiency);

(3) officers licensed after the effective date of this rule must not ever have had a license or certificate issued by the commission suspended or revoked;

(4) meet the continuing education requirements for the previous training cycle;

(5) officers licensed after the effective date of this rule must meet the current enrollment standards; and

(6) for firearms related certificates, not be prohibited by state or federal law or rule from attending training related to firearms or from possessing a firearm.

(b) The commission may refuse an application if:

(1) an applicant has not been reported to the commission as meeting all minimum standards, including any training or testing requirements;

(2) an applicant has not affixed any required signature;

(3) required forms are incomplete;

(4) required documentation is incomplete, illegible, or is not attached; or

(5) an application contains a false assertion by any person.

(c) The commission shall cancel and recall any certificate if the applicant was not qualified for its issue and it was issued:

(1) by mistake of the commission or an agency; or

(2) based on false or incorrect information provided by the agency or applicant.

(d) If an application is found to be false, any license or certificate issued to the appointee by the commission will be subject to cancellation and recall.

(e) Academic degree(s) must be issued by an accredited college or university.

(f) The effective date of this section is March 1, 2002. [~~2001.~~]

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 October 1, 2001.

TRD-200105931
Edward T. Laine
Chief, Professional Standards and Administrative Operations
Texas Commission on Law Enforcement Officer Standards and Education
Proposed date of adoption: March 1, 2002
For further information, please call: (512) 936-7700

♦ ♦ ♦

**37 TAC §221.3**

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §221.3 concerning peace officer proficiency. The proposed amendment to this subsection clarifies that in order to qualify for an intermediate peace officer proficiency certificate, new legislation requires that an applicant must meet all proficiency requirements including two additional courses. In subsection (3)(F) and (G) of this section new legislation mandates that two new courses, an asset forfeiture course and a racial profiling course be completed if the basic peace officer certificate was issued or qualified for on or after January 1, 1987, the licensee must also complete all of the current intermediate peace officer certification courses. The amendment also proposes a change to the effective date in subsection (d) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

This new section is proposed for amendment under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by this proposed rule: Texas Occupations Code Annotated, Chapter 1701, §1701.151 - General Powers.

*§221.3. Peace Officer Proficiency.*

(a) To qualify for a basic peace officer proficiency certificate, an applicant must meet all proficiency requirements including:

(1) one year experience as a peace officer; and

(2) successful completion of a course of instruction provided by the employing agency on federal and state statutes that relate to employment issues affecting peace officers and jailers, including:

(A) civil service;

(B) compensation, including overtime compensation, and vacation time;

(C) personnel files and other employee records;

(D) management-employee relations in law enforcement organizations;

(E) work-related injuries;

(F) complaints and investigations of employee misconduct; and

(G) disciplinary actions and the appeal of disciplinary actions.

(b) To qualify for an intermediate peace officer proficiency certificate, an applicant must meet all proficiency requirements including:

(1) a basic peace officer certificate;

(2) one of the following combinations of training hours or degrees and peace officer experience:

(A) 400 training hours and eight years;

(B) 800 training hours and six years;

(C) 1200 training hours and four years or an associate's degree and four years; or

(D) 2400 training hours and two years or a bachelor's degree and two years.

(3) if the basic peace officer certificate was issued or qualified for on or after January 1, 1987, the licensee must also complete all of the current intermediate peace officer certification courses, which include:

(A) Child Abuse Prevention and Investigation;

(B) Crime Scene Investigation;

(C) Use of Force;

(D) Arrest, Search and Seizure; [~~and~~]

(E) Spanish for Law Enforcement ;

(F) Asset Forfeiture; and

(G) Racial Profiling.

(c) To qualify for an advanced peace officer proficiency certificate, an applicant must meet all proficiency requirements including:

(1) an intermediate peace officer certificate; and

(2) one of the following combinations of training hours or degrees and peace officer experience:

(A) 800 training hours and 12 years;

(B) 1200 training hours and nine years or an associate's degree and six years;

(C) 2400 training hours and six years or a bachelor's degree and five years;

(d) To qualify for a master peace officer proficiency certificate, an applicant must meet all proficiency requirements including:

(1) an advanced peace officer certificate; and

(2) one of the following combinations of training hours or degrees and peace officer experience:

(A) 1200 training hours and 20 years or an associate's degree and 12 years;

(B) 2400 training hours and 15 years or a bachelor's degree and nine years;

(C) 3300 training hours and 12 years or a master's degree and seven years, or

(D) 4000 training hours and 10 years or a doctoral degree and five years.

(e) The effective date of this section is March 1, 2002. [~~2001.~~]

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 October 1, 2001.

TRD-200105932
Edward T. Laine
Chief, Professional Standards and Administrative Operations
Texas Commission on Law Enforcement Officer Standards and Education
Proposed date of adoption: March 1, 2002
For further information, please call: (512) 936-7700

♦ ♦ ♦

**37 TAC §221.13**

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §221.13 concerning emergency telecommunications proficiency. The proposed amendment to subsection (b)(3) and (4) of this section clarifies that in order to qualify for an intermediate emergency telecommunications proficiency certificate, new legislation requires that an applicant must meet all proficiency requirements including 120 hours of training and if the basic telecommunications certificate was issued or qualified for on or after January 1, 2000, successful completion of the required courses as specified by the Commission, which include: Cultural Diversity, Ethics in Law Enforcement, Crisis Communications, TCIC/NCIC for Full Access Operators; NLETS/TLETS; or Criminal Law; and Spanish for Law Enforcement. Subsection (c)(3) of this section clarifies that to qualify for an advanced telecommunications proficiency certificate, an applicant must meet all proficiency requirements including: an intermediate telecommunications certificate, at least four years of experience in public safety telecommunications, and 240 training hours. The amendment also proposes a change to the effective date in subsection (d) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

This new section is proposed for amendment under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by this proposed rule: Texas Occupations Code Annotated, Chapter 1701, §1701.151 - General Powers.

*§221.13. Emergency Telecommunications Proficiency.*

(a) To qualify for a basic telecommunications proficiency certificate, an applicant must meet all proficiency requirements including:

(1) successful completion of a 40-hour course developed or approved by the commission; and

(2) one year of experience in public safety telecommunications.

(b) To qualify for an intermediate telecommunications proficiency certificate, an applicant must meet all proficiency requirements including:

(1) basic telecommunications certification;

(2) at least two years experience in public safety telecommunications; [~~and~~]

(3) 120 hours of training; and

(4) [~~(3)~~] if the basic telecommunications certificate was issued or qualified for on or after January 1, 2000, successful completion of required courses as specified by the commission, which include:

(A) Cultural Diversity;

(B) Ethics for Law Enforcement;

(C) Crisis Communications;

(D) TCIC/NCIC for Full Access Operators; NLETS/TLETS; or Criminal Law; and

(E) Spanish for Law Enforcement.

(c) To qualify for an advanced telecommunications proficiency certificate, an applicant must meet all proficiency requirements including:

(1) intermediate telecommunications certificate;

(2) at least four years experience in public safety telecommunications; and

(3) 240 training hours. [~~successful completion of required courses as specified by the commission.~~]

(d) The effective date of this section is March 1, 2002. [~~2001.~~]

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 October 1, 2001.

TRD-200105933
Edward T. Laine
Chief, Professional Standards and Administrative Operations
Texas Commission on Law Enforcement Officer Standards and Education
Proposed date of adoption: March 1, 2002
For further information, please call: (512) 936-7700

♦ ♦ ♦

## CHAPTER 223. ENFORCEMENT

### 37 TAC §223.3

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §223.3 concerning the answer required section. For consistency purposes, the proposed amendment to subsection (d)(3) of this section includes the deletion of the abbreviated term, "Tex. Admin." which will be substituted by the term, "Texas Administrative Code." The amendment also proposes a change to the effective date in subsection (f) of this section.

Dr. D.C. Jim Dozier, Executive Director of the Commission, has determined that for the first five-year period that the proposed amended section is in effect there will be no new fiscal implications for state or local government as a result of enforcing or administering the rule.

Dr Dozier has also determined that for each year of the first-five years this section is in effect, there will be no new anticipated public benefit as a result of enforcing this rule. There will be no effect on small or micro businesses. There will be no new anticipated increase in economic cost to individuals who are required to comply with the rule as proposed.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 936-7714.

This new section is proposed for amendment under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

The following statute is affected by this proposed rule: Texas Occupations Code Annotated, Chapter 1701, §1701.151 - General Powers.

*§223.3. Answer Required.*

(a) In order to preserve the right to a hearing as described in §223.1 of this chapter (relating to License Action and Notification), a person whose license the executive director proposes to deny, cancel, suspend, or revoke must file an answer either consenting to the penalty recommended by the executive director in his petition, or requesting a contested case hearing. An answer must be filed not later than 20 days after the date the respondent is provided with notice of the executive director's petition. Failure to file a timely answer may result in the issuance of a default order.

(b) The answer described in subsection (a) of this section may be in the form of a general denial as that term is used in the district courts of the State of Texas.

(c) If a respondent fails to file a timely answer as required by subsection (a) of this section, the executive director may recommend to the commission that it enter a default order against the respondent. The executive director may support the motion with documentary evidence, including affidavits, exhibits and pleadings, and oral testimony, as may be appropriate to demonstrate that the respondent received the petition and failed to file a timely answer. The commission will consider motions for default orders at its quarterly commission meetings. If the executive director moves for issuance of a default order under this section, it is not necessary to set the matter for hearing under §223.7 of this chapter (relating to Contested Cases and Hearings). The commission may grant the default order requested by the executive director, or may order the case referred to SOAH for a contested case hearing.

(d) If a person files a timely answer as required by subsection (a) of this section, but fails to appear at the contested case hearing after receiving timely and adequate notice, the executive director may move for default judgment against the respondent as provided by SOAH rule, 1 Texas Administrative [~~Tex. Admin.~~] Code, §155.55.

(e) Upon issuance of a default order by the commission, notice shall be provided to the respondent in accordance with §223.1 of this chapter (relating to License Action and Notification).

(f) The effective date of this section is March 1, 2002. [~~2001.~~]

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 October 1, 2001.

TRD-200105934

Edward T. Laine

Chief, Professional Standards and Administrative Operations

Texas Commission on Law Enforcement Officer Standards and Education

Proposed date of adoption: March 1, 2002

For further information, please call: (512) 936-7700

♦ ♦ ♦

# TITLE 40. SOCIAL SERVICES AND ASSISTANCE

# PART 1. TEXAS DEPARTMENT OF HUMAN SERVICES

## CHAPTER 3. TEXAS WORKS

The Texas Department of Human Services (DHS) proposes new §3.7214, concerning categorically eligible households, in its Texas Works Chapter. DHS also proposes new §3.7701, concerning services, and §3.7702, concerning eligibility requirements, in new Subchapter XX, Temporary Assistance for Needy Family Non-Cash Services in its Texas Works chapter. The purpose of the new section §3.7214 is to specify how DHS determines categorical eligibility for food stamps. New sections §3.7701 and §3.7702 are proposed to extend food stamp eligibility to recipients of TANF-funded services as allowed by federal rules.

James R. Hine, Commissioner, has determined that for the first five-year period the proposed sections will be in effect there will be fiscal implications for state government as a result of enforcing or administering the sections. There will be no fiscal implications for local government as a result of enforcing of administering the sections.

The effect on state government for the first five-year period the sections will be in effect is an estimated additional cost of $39,935 in fiscal year (FY) 2002; $22,260 in FY 2003; $0 in FY 2004; $0 in FY 2005; and $0 in FY 2006.

Mr. Hine also has determined that for each year of the first five years sections are in effect the public benefit anticipated as a result of adoption of the proposed rules will be additional services for TANF recipients. There will be no effect on small or micro businesses as a result of enforcing or administering the sections, because the sections apply to eligibility requirements eligibility for food stamp benefits, not the operation of businesses. There is no anticipated economic cost to persons who are required to comply with the proposed sections and the sections have no fiscal impact on local employment.

Questions about the content of this proposal may be directed to Eric McDaniel at (512) 438-2909 in DHS's Programs and Policy Section. Written comments on the proposal may be submitted to Supervisor, Rules and Handbooks Unit-15, Texas Department of Human Services E-205, P.O. Box 149030, Austin, Texas 78714-9030, within 30 days of publication in the *Texas Register*.

Under §2007.003(b) of the Texas Government Code, the department has determined that Chapter 2007 of the Government Code does not apply to these rules. Accordingly, the department is not required to complete a takings impact assessment regarding these rules.

## SUBCHAPTER AA. SPECIAL HOUSEHOLDS

### 40 TAC §3.2714

The new section is proposed under the Human Resources Code, Title 2, Chapters 22, 31, and 33, which authorizes the department to administer financial and nutritional assistance programs.

The new section implements the Human Resources Code, §§22.001- 22.030, §§31.001-31.076, and §§33.001-33.027.

*§3.2714. Categorically Eligible Households.*

The Texas Department of Human Services determines categorical eligibility for food stamps as specified in 7CFR 273.2(j)(2)(i) - (v) for households with gross income not exceeding 165% of the Federal Poverty Income Limit.

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 October 1, 2001.

TRD-200105898

Paul Leche

General Counsel, Legal Services

Texas Department of Human Services

Earliest possible date of adoption: November 11, 2001

For further information, please call: (512) 438-3734

♦ ♦ ♦

## SUBCHAPTER XX. TEMPORARY ASSISTANCE FOR NEEDY FAMILIES NON-CASH SERVICES

### 40 TAC §3.7701, §3.7702

The new sections are proposed under the Human Resources Code, Title 2, Chapters 22, 31, and 33, which authorizes the department to administer financial and nutritional assistance programs.

The new sections implement the Human Resources Code, §§22.001- 22.030, §§31.001-31.076, and §§33.001-33.027.

*§3.7701. Services.*

The Department of Human Services provides information and referral services to all food stamp applicants.

*§3.7702. Eligibility Requirements.*

For purposes of food stamp eligibility an applicant is considered a recipient of Temporary Assistance for Needy Families (TANF) Non-Cash

Services if the household's countable liquid resources do not exceed $5000, and the fair market value of the household's countable vehicle(s) does not exceed $15,000 per vehicle. Prepaid burial funds of $7,500 per each member of the certified group are excluded.

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 October 1, 2001.

TRD-200105899
Paul Leche
General Counsel, Legal Services
Texas Department of Human Services
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 438-3734

♦ ♦ ♦

# CHAPTER 3. TEXAS WORKS
# SUBCHAPTER QQ. FINGER IMAGING

## 40 TAC §3.7001, §3.7002

The Texas Department of Human Services (DHS) proposes amendments to §3.7001, concerning finger imaging and §3.7002, concerning individuals exempt from finger imaging requirements in its Texas Works chapter. The purpose of the amendments is to update terminology in §3.7001 and to exempt elderly or disabled clients from the finger imaging requirement in §3.7002. Elderly or disabled clients will be exempt from the finger imaging requirement if it causes an undue burden.

James R. Hine, Commissioner, has determined that for the first five-year period the proposed sections will be in effect there will be fiscal implications for state government as a result of enforcing or administering the sections. There will be no fiscal implications for local government as a result of enforcing of administering the sections.

The effect on state government for the first five-year period the sections will be in effect is an estimated additional cost of $1,484 in fiscal year (FY) 2001; $4,240 in FY 2002; $0 in FY 2003; $0 in FY 2004; and $0 in FY 2005.

Mr. Hine also has determined that for each year of the first five years sections are in effect the public benefit anticipated as a result of adoption of the proposed rules will be greater access for elderly or disabled individuals who apply for TANF and/or food stamp benefits. There will be no effect on small or micro businesses as a result of enforcing or administering the sections, because the sections apply to undue burdens that would prevent clients from participating in the Food Stamp and TANF programs, not the operation of businesses. There is no anticipated economic cost to persons who are required to comply with the proposed sections and the sections have no fiscal impact on local employment.

Questions about the content of this proposal may be directed to Eric McDaniel at (512) 438-2909 in DHS's Programs and Policy Section. Written comments on the proposal may be submitted to Supervisor, Rules and Handbooks Unit-15, Texas Department of Human Services E-205, P.O. Box 149030, Austin, Texas 78714-9030, within 30 days of publication in the *Texas Register*.

Under §2007.003(b) of the Texas Government Code, the department has determined that Chapter 2007 of the Government Code does not apply to these rules. Accordingly, the department is not required to complete a takings impact assessment regarding these rules.

The amendments are proposed under the Human Resources Code, Title 2, Chapters 22, 31, and 33 which authorizes the department to administer public, financial, and nutritional assistance programs.

The amendments implement the Human Resources Code, §§22.001- 22.030, §§31.001-31.076, and §§33.001-33.027.

*§3.7001. Finger Imaging Requirements.*

(a) Temporary Assistance to Needy Families (TANF) [~~Aid to Families with Dependent Children (AFDC)~~]. TANF [~~AFDC~~] adults and minor parents with TANF [~~AFDC~~] children (including disqualified household members) as stipulated in Human Resources Code, §31.0325 must comply with the requirements of the finger imaging process when an application for TANF [~~AFDC~~] is filed with the Texas Department of Human Services (DHS). Finger images must be taken or be on record at the time TANF [~~AFDC~~] periodic reviews are initiated.

(b) (No change.)

(c) Fraud referral process. Individuals found to be participating or attempting to participate in the TANF [~~AFDC~~] or food stamp programs twice in the same month will be referred for fraud determination as specified in §3.3401 of this title (relating to Fraud) and §3.3402 of this title (relating to Food Stamps as Obligations of the United States).

*§3.7002. Individuals Exempt from Finger Imaging Requirements.*

(a) Temporary Assistance to Needy Families (TANF) [~~Aid to Families with Dependent Children (AFDC)~~]. Individuals applying for or receiving TANF [~~AFDC~~] are exempt if they:

(1) have filed an appeal and have not waived continued benefits;

(2) are certified out of the office or are unable to come into the office;

(3) are physically unable to provide the requested finger images; [~~or~~ ]

(4) temporarily cannot comply with the requirements of the finger imaging process due to equipment failure; or[~~.~~]

(5) are elderly or disabled and DHS determines that the requirement would cause an undue burden. An undue burden may be physical, mental, emotional, or an age-related condition.

(b) Food stamps. Individuals applying for or receiving food stamps are exempt if they:

(1) are certified out of the office or are unable to come into the office;

(2) are physically unable to provide the requested finger images;

(3) temporarily cannot comply with the requirements of the finger imaging process due to equipment failure; [~~or~~]

(4) are disqualified or ineligible to participate in the food stamp program; or[~~.~~]

(5) are elderly or disabled and DHS determines that the requirement would cause an undue burden. An undue burden may be physical, mental, emotional, or an age-related condition.

(c) Exemptions. Exemptions will be redetermined at each initial application or complete review. If a physical or mental disability is not obvious, DHS will require proof of the disability in writing from a medical professional.

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 October 1, 2001.

TRD-200105900
Paul Leche
General Counsel, Legal Services
Texas Department of Human Services
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 438-3734

♦ ♦ ♦

## SUBCHAPTER WW. TEMPORARY ASSISTANCE FOR NEEDY FAMILIES-STATE PROGRAM

### 40 TAC §§3.7601 - 3.7605, 3.7607, 3.7609

The Texas Department of Human Services (DHS) proposes new §3.7601, concerning definitions, §3.7602, concerning establishment of temporary assistance for needy families - state program , §3.7603, concerning eligibility, §3.7604 concerning household determination, §3.7605, concerning time limitations, §3.7607, concerning employment services, and §3.7609, concerning failure to comply with CHOICES, in new Subchapter WW, Temporary Assistance for Needy Family- State Program in its Texas Works chapter. The purpose of the new sections is to comply with Human Resources Code, Chapter 34, which was added by the 77th Texas Legislature. Chapter 34 creates a new state-funded Temporary Assistance for Needy Families (TANF) program to provide financial assistance and workforce services to two- parent families.

James R. Hine, Commissioner, has determined that for the first five-year period the proposed sections will be in effect there will be fiscal implications for state government as a result of enforcing or administering the sections. There will be no fiscal implications for local government as a result of enforcing of administering the sections.

The effect on state government for the first five-year period the sections will be in effect is an estimated additional cost of $39,935 in fiscal year (FY) 2001; $109,445 in FY 2002; $0 in FY 2003; $0 in FY 2004; and $0 in FY 2005.

Mr. Hine also has determined that for each year of the first five years sections are in effect the public benefit anticipated as a result of adoption of the proposed rules will be services that address the needs of eligible two-parent families. There will be no effect on small or micro businesses as a result of enforcing or administering the sections, because the sections apply to eligibility requirements for two-parent families, not the operation of businesses. There is no anticipated economic cost to persons who are required to comply with the proposed sections and the sections have no fiscal impact on local employment.

Questions about the content of this proposal may be directed to Eric McDaniel at (512) 438-2909 in DHS's Programs and Policy Section. Written comments on the proposal may be submitted to Supervisor, Rules and Handbooks Unit-15, Texas Department of Human Services E-205, P.O. Box 149030, Austin, Texas 78714-9030, within 30 days of publication in the *Texas Register*.

Under §2007.003(b) of the Texas Government Code, the department has determined that Chapter 2007 of the Government Code does not apply to these rules. Accordingly, the department is not required to complete a takings impact assessment regarding these rules.

The new sections are proposed under the Human Resources Code, Title 2, Chapter 34, which authorizes DHS to adopt rules necessary to implement the program.

The new sections implement the Human Resources Code, §§34.001- 34.007.

*§3.7601. Definitions.*

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

(1) Temporary Assistance for Needy Families-State Program (TANF-SP)--cash and medical assistance is provided to two-parent families eligible for assistance under the TANF-SP program. In eligible families, two parents receive benefits.

(2) TP--Type Program.

*§3.7602. Establishment of Temporary Assistance for Needy Families - State*

Program. Effective October 1, 2001, the Texas Department of Human Services (DHS) established the Temporary Assistance for Needy Families-State Program (TANF-SP), which was created by Chapter 34, Human Resources Code, in the 77th Texas Legislative Session. The TANF-SP program provides cash and medical assistance to two-parent families eligible for financial assistance under the TANF program. Eligible families have two parents who receive benefits.

*§3.7603. Eligibility.*

(a) Requirements. To be eligible for services under the TANF-SP program, the family must meet the requirements of this subchapter and the TANF requirements for applicants specified in this chapter.

(b) TANF-SP Child Support Requirements. The Texas Department of Human Services (DHS) adheres to the requirements and procedures stated in 45 Code of Federal Regulations §§232.11-232.20, §§232.40-232.47, and §232.49 with an exception related to penalties for noncompliance. In regard to recipients subject to the requirements specified in §3.301(d) of this title (relating to Responsibilities of Clients and the Texas Department of Human Services (DHS)), DHS applies a noncompliance penalty as specified in §3.301(d)(5)(A) of this title (relating to Responsibilities of Clients and the Texas Department of Human Services (DHS)).

*§3.7604. Household Determination.*

(a) For households that are members of the State Welfare Reform Control Group as described in §3.6004 of this title (relating to Applicability of Aid to Families with Dependent Children (AFDC) policies resulting from Human Resources Code §31.0031, Dependent Child's Income; Human Resources Code §31.012, Mandatory Work or Participation in Employment Activities Through the Job Opportunities and Basic Skills Training Program; Human Resources Code §31.014, Two-Parent Families; and Human Resources Code §31.032, Investigation and Determination of Eligibility), a child must live with both parents and be deprived because the principal wage earner parent is unemployed, as stipulated in 45 Code of Federal Regulations §233.100(a)(1) and 233.100(a)(3).

(b) The Texas Department of Human Services determines TANF-SP deprivation as specified in Human Resources Code §31.014(b) for all other households.

*§3.7605. Time Limitations.*

The TANF-SP and TANF programs apply benefit time limits in the same manner.

*§3.7607. Employment Services.*

TANF-SP clients must meet employment services requirements as specified in §3.1101 of this title (relating to Who is Required to Participate).

*§3.7609. Failure to Comply with CHOICES Program.*

(a) Clients who do not comply with a CHOICES requirement and cannot establish good cause are sanctioned.

(1) TANF-SP clients who are members of the State Welfare Reform Control Group as described in §3.6001 of this title (relating to Applicability of Aid to Families with Dependent Children (AFDC) Policies Resulting from Human Resources Code §31.0031, Relating to the Personal Responsibility Agreement) and who do not comply with a CHOICES requirement, and who cannot establish good cause are sanctioned as stated in 45 Code of Federal Regulations §250.34(a)(1) and §250.34(c)(2).

(2) All other TANF-SP clients who do not comply with a CHOICES requirement and cannot establish good cause are sanctioned as specified in §3.301(d)(5) of this title (relating to Responsibility of Clients and the Texas Department of Human Services (DHS).

(b) Clients reestablish eligibility for TANF-SP according to procedures specified in §3.1105 of this title (relating to Reestablishing Eligibility).

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 October 1, 2001.

TRD-200105897
Paul Leche
General Counsel, Legal Services
Texas Department of Human Services
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 438-3734

♦ ♦ ♦

## CHAPTER 7. REFUGEE CASH ASSISTANCE PROGRAM
## SUBCHAPTER C. ELIGIBILITY DETERMINATION

### 40 TAC §7.301

The Texas Department of Human Services (DHS) proposes an amendment to §7.301, concerning application and interview in its Refugee Cash Assistance Program chapter. The purpose of the amendment is to stipulate that refugees can be given telephone interviews for applications and reviews.

James R. Hine, Commissioner, has determined that for the first five-year period the proposed section will be in effect there will be no fiscal implications for state or local governments as a result of enforcing or administering the sections.

Mr. Hine also has determined that for each year of the first five years sections are in effect the public benefit anticipated as a result of adoption of the proposed rules will be greater access for refugees applying for Refugee cash or medical assistance. There will be no effect on small or micro businesses as a result of enforcing or administering the sections, because the section applies to applicants and recipients of Refugee cash and medical assistance, not the operation of businesses. There is no anticipated economic cost to persons who are required to comply with the proposed sections and the sections have no fiscal impact on local employment.

Questions about the content of this proposal may be directed to Eric McDaniel at (512) 438-2909 in DHS's Programs and Policy Section. Written comments on the proposal may be submitted to Supervisor, Rules and Handbooks Unit-15, Texas Department of Human Services E-205, P.O. Box 149030, Austin, Texas 78714-9030, within 30 days of publication in the *Texas Register*.

Under §2007.003(b) of the Texas Government Code, the department has determined that Chapter 2007 of the Government Code does not apply to these rules. Accordingly, the department is not required to complete a takings impact assessment regarding these rules.

The amendment is proposed under the Human Resources Code, Title 2, Chapters 22 and 31, which authorizes the department to administer public and financial assistance programs.

The amendment implements the Human Resources Code, §§22.001-22.030 and §§31.001-31.076.

*§7.301. Application and Interview.*

An applicant must complete and sign an application form to apply for refugee cash assistance. The applicant must also have an [~~a face-to-face~~] interview with a Texas Department of Human Services (DHS) advisor. This interview can be a face-to-face or a telephone interview.

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 October 1, 2001.

TRD-200105901
Paul Leche
General Counsel, Legal Services
Texas Department of Human Services
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 438-3734

♦ ♦ ♦

## CHAPTER 10. MEDICAID FOR TRANSITIONING FOSTER CARE YOUTH
## SUBCHAPTER A. ELIGIBILITY REQUIREMENTS

### 40 TAC §§10.1002, 10.1004, 10.1006, 10.1008

The Texas Department of Human Services (DHS) proposes new §10.1002, concerning application procedures, §10.1004, concerning eligibility requirements, §10.1006, concerning Medicaid eligibility, and §10.1008, concerning right to appeal, in its new

Medicaid for Transitioning Foster Care Youth chapter. The purpose of the new sections is to extend Medicaid coverage to eligible individuals who leave foster care.

James R. Hine, Commissioner, has determined that for the first five-year period the proposed sections will be in effect there will be fiscal implications for state government as a result of enforcing or administering the sections. There will be no fiscal implications for local governments as a result of enforcing or administering the sections.

The effect on state government for the first five-year period the sections will be in effect is an estimated additional cost of $88,548 in fiscal year (FY) 2002; $16,788 in FY 2003; $16,788 in FY 2004; $16,788 in FY 2005; and $16,788 in FY 2006.

Mr. Hine also has determined that for each year of the first five years the sections are in effect the public benefit anticipated as a result of adoption of the proposed rules will be a program that assists youth make the transition from foster care to independent living. There will be no effect on small or micro businesses as a result of enforcing or administering the sections, because the section provides medical coverage to a small population. There is no anticipated economic cost to persons who are required to comply with the proposed sections.

Questions about the content of this proposal may be directed to Eric McDaniel at (512)438-2909 in DHS's Programs and Policy Section. Written comments on the proposal may be submitted to Supervisor, Rules and Handbooks Unit-221, Texas Department of Human Services E-205, P.O. Box 149030, Austin, Texas 78714-9030, within 30 days of publication in the *Texas Register*.

Under §2007.003(b) of the Texas Government Code, the department has determined that Chapter 2007 of the Government Code does not apply to these rules. Accordingly, the department is not required to complete a takings impact assessment regarding these rules.

The new sections are proposed under the Human Resources Code, Title 2, Chapters 22 and 32, which authorizes the department to administer public and medical assistance programs and under Texas Government Code §531.021, which provides the Health and Human Services Commission with the authority to administer federal medical assistance funds.

The sections implement the Human Resources Code, §§22.001-22.030 and §§32.001-32.042.

*§10.1002. Application Procedures.*

(a) Initial application. The Texas Department of Protective and Regulatory Services (PRS) certifies the income and resources of applicants for medical assistance on the date the individual leaves foster care. PRS notifies the Texas Department of Human Services' Data Control Unit to authorize medical assistance for the individual under this coverage.

(b) Recertification. The recertification process for eligible individuals may be conducted by mail or telephone.

(c) Coverage period. Eligible individuals remain eligible for 12 calendar months after certification and each recertification.

*§10.1004. Client Eligibility Requirements.*

(a) Eligible group. The eligible group consists of individuals who are in foster care when they leave Texas Department of Protective and Regulatory Services conservatorship on their 18th birthday until the month of their 21st birthday. The Foster Care Independence Act of 1999, created by Public Law 106-169, authorizes Medicaid coverage for these individuals.

(b) Eligibility Requirements. Individuals transitioning out of foster care must meet the following requirements to be eligible for medical assistance:

(1) Age. Individuals must be age 18 through the month of their 21st birthday.

(2) Citizenship. Citizenship requirements are the same as the requirements for Temporary Assistance for Needy Families (TANF) applicants outlined in DHS's TANF rules in Chapter 3 of this title (relating to Texas Works).

(3) Resources. Resource limits and types of countable and exempt resources for youth transitioning out of foster care are the same as those outlined in DHS's Children and Pregnant Women (CPW) programs, with the following exceptions:

(A) The resource limit is $10,000.

(B) Any financial benefit used for the purpose of educational or vocational training, such as scholarships, student loans, or grants, is excluded as a resource.

(C) Any financial benefit used for the purpose of housing is excluded as a resource.

(D) Any grants or subsidies obtained as a result of the Foster Care Independence Act of 1999 are excluded as a resource.

(4) Social Security number. The individual must meet the social security number requirement stipulated in the 42 Code of Federal Regulations, §435.910.

(5) Income. Income eligibility is determined using the TANF eligibility requirements outlined in the TANF rules in Chapter 3 of this title (relating to Texas Works) with the following exceptions:

(A) The income limit is 400% of the federal poverty level adjusted annually to federal requirements.

(B) Any financial benefit used for the purpose of educational or vocational training, such as scholarships, student loans, or grants is excluded from income.

(C) Any financial benefit used for the purpose of housing is excluded from income.

(D) Any grants or subsidies obtained as a result of the Foster Care Independence Act of 1999 are excluded from income.

(E) The TANF 90% disregard is not used.

(6) Residency. The individual must meet residence requirements stipulated in the 42 Code of Federal Regulations., §435.403.

(7) Other Eligibility. Individuals must not be covered by a health benefits plan offering adequate benefits as defined by the Health and Human Services Commission.

*§10.1006. Medicaid Eligibility.*

(a) Individuals must meet the requirement stipulated in the Social Security Act, §1092(a)(34) for three months prior to eligibility.

(b) Medicaid eligibility begins the first day in the month the individual meets all eligibility criteria.

(c) Individuals must not be eligible for other Medicaid coverage.

*§10.1008. Right to Appeal.*

Applicants and recipients have the right to appeal DHS decisions. Notice of the right to appeal and information about free legal representation is included in the Medicaid Action Notice. Decisions may be appealed according to procedures found in Chapter 79, Subchapter M of this title (relating to Appeals Process).

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 October 1, 2001.

TRD-200105902
Paul Leche
General Counsel, Legal Services
Texas Department of Human Services
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 438-3734

♦ ♦ ♦

# TITLE 43. TRANSPORTATION

## PART 1. TEXAS DEPARTMENT OF TRANSPORTATION

### CHAPTER 9. CONTRACT MANAGEMENT

### SUBCHAPTER A. GENERAL

**43 TAC §9.5**

The Texas Department of Transportation proposes amendments to §9.5, concerning special labor provisions for public works contracts.

EXPLANATION OF PROPOSED AMENDMENTS

Government Code, Chapter 2258, Subchapter A, prescribes the method by which a public body shall determine the general prevailing rate of per diem wages for public works contracts. Pursuant to this authority, the commission has previously adopted §9.5 to specify the process by which the department will establish prevailing wage rates for department building and highway improvement contracts.

Senate Bill 311, 77th Legislature, 2001, amended Government Code, Subchapter A by amending §2258.022 to provide for additional wage survey and determination requirements associated with counties bordering the United Mexican States or counties adjacent to counties bordering the United Mexican States. Section 9.5(c) is therefore amended to include these additional wage survey and determination requirements in order to comply with S.B. 311.

For highway improvement contracts in the affected area, the department shall conduct a statewide wage rate survey and a separate wage rate survey in each county of the affected area. The prevailing wage rate for each job classification will be established on a countywide basis in the affected area based on the higher of the rate determined from the county survey, the arithmetic mean between the rate determined from the county survey and the rate determined by the statewide survey, or the arithmetic mean between the rate determined from the county survey and the rate determined by the United States Department of Labor, if the survey used to determine that rate was conducted within the preceding three-year period. For those municipalities within the affected area that have a population of 500,000 or more, the prevailing wage rate for each job classification will be determined for the geographic limits of the municipality in the manner previously described.

For highway improvement contracts in non-affected areas, the department shall continue to adopt the prevailing wage rate for each job classification as determined by the United States Department of Labor in accordance with the Davis-Bacon Act, 40 United States Code §276a, and its subsequent amendments, provided the rates are based on a survey conducted within the preceding three-year period.

For building contracts, the department shall continue to adopt the prevailing wage rate for each job classification as determined by the General Services Commission.

FISCAL NOTE

James Bass, Director, Finance Division, has determined that for the first five-year period the amendments are in effect, there will be no fiscal implications for state or local governments as a result of enforcing or administering the amendments. There are no anticipated economic costs for persons required to comply with the section as proposed.

Thomas R. Bohuslav, Director, Construction Division has certified that there will be no significant impact on local economies or overall employment as a result of enforcing or administering the amended section.

PUBLIC BENEFIT

Mr. Bohuslav has also determined that for each year of the first five years the amended section is in effect, the public benefit anticipated as a result of these new wage survey and determination requirements will be the existence of prevailing wage rates that better reflect the composition of the Texas workforce. There will be no adverse economic effect on small businesses.

SUBMITTAL OF COMMENTS

Written comments on the proposed amendments may be submitted to Thomas R. Bohuslav, Director, Construction Division, 125 East 11th Street, Austin, Texas 78701-2483. The deadline for receipt of comments is 5:00 p.m. on November 12, 2001.

STATUTORY AUTHORITY

The amendments are proposed under Transportation Code, §201.101, which provides the Texas Transportation Commission with the authority to establish rules for the conduct of the work of the Texas Department of Transportation, and more specifically, Government Code, §2258.022, which authorizes the Texas Department of Transportation, as a public body, to determine the general prevailing rate of per diem wages for public work contracts.

No statutes, articles, or codes are affected by the proposed amendments.

*§9.5. Special Labor Provisions for Public Works Contracts.*

(a) Purpose. Government Code, Chapter 2258, requires payment of the general prevailing rate of per diem wages, including legal holidays and overtime work, in the locality in which work is to be performed for each craft or type of worker needed to execute a public works contract on behalf of the state. This section prescribes the policies and procedures by which the Texas Department of Transportation will ascertain the prevailing rate of wages, and will administer and enforce the prevailing rate of wages as required by Government Code, Chapter 2258.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Area engineer--The chief administrative officer in charge of an area office of the department.

(2) Building contract--A contract awarded by the department for the construction or repair of a department building structure, but not designated by the department as a maintenance contract.

(3) Commission--The Texas Transportation Commission.

(4) Complainant--A worker who files a complaint under this section.

(5) Contractor--A firm awarded a public works contract.

(6) Department--The Texas Department of Transportation.

(7) District engineer--The chief administrative officer in charge of a district of the department.

(8) Highway improvement contract--A contract awarded under Transportation Code, Chapter 223, for the improvement of a segment of the state highway system, but not designated by the department as routine maintenance.

(9) Prevailing wage rate--The general prevailing rate of per diem wages, including legal holidays and overtime work, in the locality in which work is to be performed for each craft or type of worker needed to execute a public works contract on behalf of the state.

(10) Public works contract--A building contract or a highway improvement contract.

(c) Determination of prevailing wage rate.

(1) Highway improvement contracts.

(A) For highway improvement contracts, the department shall adopt [~~the~~] prevailing wage rates as prescribed by Government Code, Chapter 2258 [~~rate for each job classification as determined by the United States Department of Labor in accordance with the Davis-Bacon Act, 40 United States Code §276a. The department will not utilize any Davis-Bacon wage rate survey conducted three or more years before the bidding of a project~~].

(B) For purposes of this paragraph, contributions made or costs reasonably anticipated for bona fide fringe benefits under the Davis-Bacon Act, §1(b)(2), on behalf of workers are considered wages paid to such workers. Whenever the prescribed minimum wage rate in the contract for workers includes a fringe benefit which is not expressed as an hourly rate, the contractor or subcontractors, as appropriate, shall either pay the benefit as stated in the wage determinations or shall pay another bona fide fringe benefit or an hourly cash equivalent.

(2) Building contract. For building contracts, the department shall adopt the prevailing wage rate for each job classification as determined by the General Services Commission.

(d) Contract procedures.

(1) Contract specification. The department shall specify the applicable prevailing wage rates in its public works contracts and in the call for bids for such contracts. The specified rates shall apply as minimum wage rates for contracts. Failure of the department to specify the prevailing wage rate in the call for the contract shall relieve the contractor and any subcontractors from liability under Government Code, Chapter 2258.

(2) Contractor responsibility. The contractor is responsible for carrying out the requirements of this section and it shall be the contractor's responsibility to ensure that each subcontractor working on the project complies with these requirements.

(3) Rate by class and type. The prevailing wage rate shall be indicated in the contract for each class and type of worker whose services are considered necessary to execute the contract. These rates shall govern as minimum wage rates for the contract and shall be conspicuously posted on the project site by the contractor for inspection by all workers employed on the project.

(4) Apprentices and trainees.

(A) Apprentices and trainees may work at less than the predetermined minimum wage rate for work they perform when they are employed pursuant to and individually registered in a bona fide apprenticeship or trainee program registered with the United States Department of Labor, Employment and Training Administration. Proof of registration will be submitted to the department.

(B) The allowable ratio of apprentices or trainees to journeyman-level employees on the project site in any craft classification shall not be greater than the ratio permitted to contractor or subcontractor under the registered program.

(5) Additional classification.

(A) This paragraph applies to highway improvement contracts.

(B) If the work performed by a worker is not covered by a job classification in the department's wage determination, the contractor or subcontractor shall submit a request to the department for an additional classification with a recommended wage rate and supporting documentation. The recommendations must be based on industry practice and the rate of comparable classifications. The department may modify or disapprove the recommended classification minimum wage rate within 30 days of receipt if the department determines that the recommended classification minimum wage rate is not based on industry practice and the rate of comparable classifications.

(C) The additional classification minimum wage rate established by the department will be effective retroactive to the first day on which work is performed in the job classification.

(6) Overtime wages. The contractor or subcontractor shall pay overtime wages pursuant to the requirements of the Fair Labor Standards Act, 29 United States Code §201, et seq.

(e) Records and inspections.

(1) For those projects funded wholly with state funds, the contractor and all subcontractors shall keep, or cause to be kept, copies of weekly payrolls for review by the department. Payroll records should show the name, occupation, number of hours worked each day, and per diem wages paid each worker together with a complete record of all deductions made from those wages. Only deductions made in accordance with the regulations issued by the United States Department of Labor (29 Code of Federal Regulations Part 3) are permitted. The initial payroll for each worker shall also indicate the employee's address and phone number. For those projects funded wholly, or in part, with federal funds, record and inspection requirements as codified in 29 Code of Federal Regulations Part 3 will apply.

(2) The contractor and subcontractor shall attach an affidavit to each payroll record certifying that the payroll is an accurate report of the full wages due and paid to each worker employed by the contractor and/or subcontractor.

(3) The contractor and subcontractor shall keep originals or copies of canceled payroll checks issued for each payroll record. These canceled checks shall be provided to the department upon request.

(4) All payroll records and related canceled checks shall be retained by the contractor and subcontractor for a period of three years after completion of the project.

(f) Enforcement.

(1) Violation. A contractor or subcontractor in violation of the prevailing wage rate is liable for penalties as set forth in this section.

(2) Initiation of proceeding. A proceeding under this section to enforce the prevailing wage rate may be initiated by the filing of a complaint in accordance with paragraph (3) of this subsection or by the department on its own motion subsequent to review of records submitted in accordance with subsection (e) of this section.

(3) Filing a complaint. A worker who is not paid the prevailing wage rate specified in the contract for his or her classification may file a complaint with the department's area engineer responsible for monitoring the project's completion. A complaint involving a building contract may be filed with the responsible area engineer or with the director of the department's Maintenance Division. The complainant shall provide, in writing, the following information:

(A) name, phone number, and address;

(B) employer;

(C) job classification;

(D) period when violation occurred and daily work hours during the period;

(E) pay rate received and amount due; and

(F) any information necessary to support the complaint.

(4) Investigation. Within five days of receipt of a complaint, including necessary supporting information, or at any time upon its own motion, the department will provide written notice to the contractor or subcontractor of an alleged violation. The contractor or subcontractor shall have ten days in which to respond in writing to the information presented against it.

(5) Good cause determination.

(A) The director of the department's Construction Division shall determine, within 30 calendar days of the date a complaint is filed whether good cause exists to believe that a contractor or subcontractor has committed a violation of the contract's prevailing wage rate requirements. Such determination will be based upon information submitted by the complainant, the contractor or subcontractor, and in accordance with subsection (e) of this section. The department shall provide written notice of its determination to the contractor and/or subcontractor and to the complainant. The department shall retain any amount due under the contract pending a final determination of the violation.

(B) For building contracts, the determination of good cause shall be made by the director of the department's Maintenance Division.

(6) Discrimination. A contractor or subcontractor shall not discriminate against any employee filing a complaint under the provisions of Government Code, Chapter 2258.

(7) Appeal. If the department determines that good cause does not exist, the complainant may file an appeal in accordance with §1.21 et seq. of this title (relating to Procedures in Contested Cases [~~Contested Case Procedure~~]).

(8) Resolution. If the department provides written notice to the parties that good cause exists, the parties shall have 14 days from the date of the written determination to voluntarily resolve the wage dispute by written agreement. If the parties fail to voluntarily resolve the dispute, the issue of the alleged violation, any penalties owed to the department, and any amounts owed to the worker shall be submitted to binding arbitration in accordance with the provisions of Civil Practice and Remedies Code, Chapter 171. The department is not a party to the arbitration proceeding.

(9) Reimbursement.

(A) If the arbitrator determines that a violation of this section occurred and awards backpay, the department shall use any amounts retained under this subsection to reimburse the worker and collect any penalties due under subsection (g) of this section. The department shall issue a check to the complainant within 30 days after receiving the arbitrator's decision.

(B) If the worker and the contractor or subcontractor voluntarily resolve the wage dispute, a signed written agreement which specifies the terms of the agreement shall be submitted to the director of the department's Construction Division. If the agreement calls for backpay, a signed statement from the worker which acknowledges receipt of the backpay must be attached to the agreement. The department shall release any amounts retained within seven days of receiving this information.

(g) Penalties. A contractor or subcontractor who violates the prevailing minimum wage requirements of a public works contract is liable to the department for a penalty of $60 for each worker employed, for each calendar day, or portion thereof, such worker is paid less than the minimum wage rate stipulated in the contract. The money collected under this subsection shall be used by the department to offset the costs incurred in the administration of this section.

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 October 1, 2001.

TRD-200105889
Richard D. Monroe
General Counsel
Texas Department of Transportation
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 463-8630

♦ ♦ ♦

## CHAPTER 15. TRANSPORTATION PLANNING AND PROGRAMMING
## SUBCHAPTER I. BORDER COLONIA ACCESS PROGRAM

### 43 TAC §§15.100 - 15.106

The Texas Department of Transportation proposes new §§15.100-15.106, concerning the border colonia access program.

EXPLANATION OF NEW SECTIONS

Senate Bill 1296, 77th Legislature, 2001, added Government Code, Chapter 1403, which requires the Texas Public Finance

Authority, in accordance with requests from the Office of the Governor, to issue general obligation bonds and notes in an aggregate amount not to exceed $175 million, and as directed by the department, to distribute the proceeds to counties as financial assistance for colonia access roadway projects to serve border colonias. Senate Bill 1296 requires the commission to establish a program to administer the use of the proceeds of the bonds and notes. Senate Bill 1296 will only take effect if the constitutional amendment proposed in Senate Joint Resolution 37, 77th Legislature, 2001 is approved by the voters. Rider 52 to the department's appropriations for Fiscal Years 2002-2003 requires the department to establish a transportation program to improve access to colonias.

Senate Bill 1296 and Rider 52 require the commission and the department to consult with the Office of the Governor, the Secretary of State, the Texas Water Development Board, and the Texas A&M University Center for Housing and Urban Development in developing the rules and procedures for the border colonia access program. The department participated in a working group including representatives of each of these entities in developing proposed rules for the commission's consideration.

New §§15.100-15.106 implement the requirements of Senate Bill 1296 and Rider 52, set forth the procedures by which an eligible county may apply for assistance under Senate Bill 1296 and Rider 52, and establish criteria by which the commission will select projects.

New §15.100 describes the purpose of new Subchapter I, Border Colonia Access Program.

New §15.101 provides definitions for words and terms used in new Subchapter I. This section defines a border colonia as a community, located in an eligible county, which is identified in the Texas Water Development Board's colonia database. In 1989, the Texas Legislature created the Economically Distressed Areas Program (Water Code, §§16.341-16.356), administered by the Texas Water Development Board, to bring water and wastewater services to economically distressed areas, as defined in Water Code, §16.341. Economically distressed areas are also commonly referred to as colonias. In 1992, the Texas Water Development Board conducted a comprehensive assessment of the state's water and wastewater needs in economically distressed areas. This 1992 Colonia Water and Wastewater Needs Report and its subsequent updates identified communities that meet the definition of economically distressed area. The identified colonias are maintained in a colonia database. As a lead state agency working with border colonias for a number of years, the Texas Water Development Board is generally viewed as having the most comprehensive database of colonias in the state. Counties wishing to participate in Economically Distressed Areas Program are required to adopt model rules for the development of subdivisions and water and wastewater services in those subdivisions that have been promulgated by the Texas Water Development Board under Water Code, §16.343. Colonias generally lack adequate infrastructure and basic services such as water and wastewater services and paved roads in or to the colonia. In order to ensure that both adequate infrastructure and basic services are available in a colonia, a county must adopt the model rules in order to be eligible for participation in the border colonia access program.

New §15.102 prescribes requirements a project must meet in order to be eligible for consideration. To be eligible, a project must be located in an eligible county, defined as a county located in the department's El Paso, Laredo, or Pharr district, and Terrell County, that has adopted the model rules. The purpose of the program is to improve access to and from border colonias through the construction and improvement of roads serving the colonias. In order to provide colonia residents with improved access to other parts of the state, and to facilitate the provision of goods and services to the colonias, this section requires a project to have a terminus at or within a border colonia and a terminus at a public road. In order to ensure that projects are designed and constructed in a safe and durable manner, this section requires a project to comply with road standards described in the appropriate American Association of State Highway and Transportation Official design guidelines, or in more stringent road standards adopted by a county under Local Government Code, §232.025.

New §15.103 prescribes the procedures by which a county may apply for assistance under the program. The department's border district offices will issue a program call to eligible counties, informing those counties of the availability of funds. In order to ensure that a project is eligible and complies with program requirements, and that project development will be carried out in an expeditious manner, an application must include a description of the work proposed, an implementation plan, a map delineating project location and termini, and documentation addressing the criteria considered by the commission in selecting projects for funding under the program.

New §15.104 prescribes criteria for project selection. These criteria are consistent with the factors in Rider 52 that the department is directed to consider in developing rules and procedures for this program. Generally, the higher the border colonia population, the more in need of goods and services that colonia will be. The condition of existing roads in and to a colonia, and whether those roads are paved, helps determine the relative need of a colonia for new and improved roads providing access to and from the colonia. In order to provide adequate educational services to children residing in colonias and provide school buses with adequate access to colonias, the commission will consider whether a project is on an existing or planned school bus route. In order to ensure that a project provides the most efficient service to the maximum number of colonia residents, while also ensuring that funding is not concentrated in a limited number of colonias, the commission will consider the number resulting from dividing the border colonia population whose residences abut the project limits by the number of miles of roadway in the project. In order to provide an objective means of ranking and selecting projects, each criterion will be assigned an equal number of points, and projects will be considered in descending rank order based on the number of points received.

New §15.105 describes the manner in which the department will apportion and distribute available funds to eligible counties under the program. In order to ensure that adequate funds are provided to those counties containing colonias with the most pressing needs, the first 50% of the available funds will be proportionally distributed to the counties based on their colonia population. Generally, the higher the border colonia population, the more in need of goods and services that colonia will be. Moreover, this will ensure that each county participating in the program receives funds for roadway projects. In order to provide an objective means of selecting additional projects, and to ensure the remaining funds are expended on the most needed projects, the remaining 50% of available funds will be distributed to the counties on a project by project basis, with projects funded in descending rank order as available funding permits. Unused funds dedicated to a county will be distributed on a project by project basis, as will funds reimbursed by a county because of uncompleted projects, or funds available as a result of a county being prohibited from participation in the program under §15.106. In order to ensure that funds are available for the maximum number of projects, funds will be distributed for a project based on a county's project cost estimates. Project costs above that estimate are the responsibility of the county, which may seek additional funds for a project under subsequent program calls.

In order to assist the department in administering the program, new §15.106 prescribes requirements that counties participating in the program must follow. Prior to receiving funds under the program, a county must enter into an agreement with the department. In that agreement, a county must agree to place a project on the county road system and must agree to maintain the road. In doing so, the state ensures that the roads will be adequately maintained. Moreover, Government Code, §1403.002(d)(4), as added by Senate Bill 1296, requires the commission to establish minimum road standards by rule. In order to ensure that project development or access on a new project is not impeded, §15.106 requires a county to agree to complete the placement of any necessary water and wastewater services in or across project right of way prior to constructing the project. In order to ensure that the environment is protected when projects are developed, a county must comply with all applicable federal, state, and local environmental laws and regulations and permitting requirements. In order to ensure that program funds are spent for authorized purposes, and to comply with the requirements for providing grants to local governments under Government Code, Chapter 783, a county may only expend funds received on eligible costs, must comply with the Uniform Grant Management Standards promulgated by the Office of the Governor, and must submit a financial report showing how it will use the funds to build the project. The department may prohibit a county from participating in the program or continuing to participate in the program if the county has not complied with program requirements. In order to ensure that counties use program funds for approved projects, the department may eliminate a project from participation in the program if it is not implemented within a reasonable time, as determined by the department in consultation with the county, and may seek reimbursement of funds received by a county if the county does not complete a project.

FISCAL NOTE

James Bass, Director, Finance Division, has determined that for each of the first five years the new sections are in effect, there will be fiscal implications for state and local governments as a result of enforcing or administering the new sections. It is estimated that the state will incur $53,400 in additional costs of administration each year of the first five years the new sections are in effect. The department anticipates that counties will incur additional costs in preparing applications for assistance under the program, and in complying with program administration requirements under §15.106, such as providing financial reports. Those costs cannot be estimated with any certainty because of the uncertainty relating to the number of projects that will receive funding, and the quality of the information that will be provided in an application or financial report. It is also anticipated that counties participating in the program will obtain increased revenues as a result of being provided program funding. The amount of increased revenues will depend on the county involved, the number of projects receiving funding, and the amount of funding available. Senate Bill 1296 authorizes the Texas Public Finance Authority to issue bonds and notes in an aggregate amount not to exceed $175 million. The entire amount authorized may be issued and distributed in the first fiscal year, or may be spread out over several years. There are no anticipated economic costs for persons required to comply with the new sections as proposed.

James Randall, Director, Transportation Planning and Programming Division, has certified that there will be no significant impact on local economies or overall employment as a result of enforcing or administering the new sections.

PUBLIC BENEFIT

Mr. Randall has also determined that for each year of the first five years the new sections are in effect, the public benefit anticipated as a result of enforcing or administering the new sections will be improved access to and from border colonias resulting from the construction and improvement of roads serving the colonias. There will be no adverse economic effect on small businesses.

PUBLIC HEARING

Pursuant to the Administrative Procedure Act, Government Code, Chapter 2001, the Texas Department of Transportation will conduct a public hearing to receive comments concerning the proposed new subchapter. The public hearing will be held at 9 a.m. on October 29, 2001, in the first floor hearing room of the Dewitt C. Greer State Highway Building, 125 East 11th Street, Austin, Texas and will be conducted in accordance with the procedures specified in 43 TAC §1.5. Those desiring to make comments or presentations may register starting at 8:30 a.m. Any interested persons may appear and offer comments, either orally or in writing; however, questioning of those making presentations will be reserved exclusively to the presiding officer as may be necessary to ensure a complete record. While any person with pertinent comments will be granted an opportunity to present them during the course of the hearing, the presiding officer reserves the right to restrict testimony in terms of time and repetitive content. Organizations, associations, or groups are encouraged to present their commonly held views and identical or similar comments through a representative member when possible. Comments on the proposed text should include appropriate citations to sections, subsections, paragraphs, etc. for proper reference. Any suggestions or requests for alternative language or other revisions to the proposed text should be submitted in written form. Presentations must remain pertinent to the issues being discussed. A person may not assign a portion of his or her time to another speaker. A person who disrupts a public hearing must leave the hearing room if ordered to do so by the presiding officer. Persons with disabilities who plan to attend this meeting and who may need auxiliary aids or services such as interpreters for persons who are deaf or hearing impaired, readers, large print or Braille, are requested to contact Randall Dillard, Director, Public Information Office, 125 East 11th Street, Austin, Texas 78701-2483, 512/463-8588 at least two working days prior to the hearing so that appropriate services can be provided.

SUBMITTAL OF COMMENTS

Written comments on the proposed new sections may be submitted to James Randall, Director, Transportation Planning and Programming Division, 125 East 11th Street, Austin, Texas 78701-2483. The deadline for receipt of comments is 5:00 p.m. on November 12, 2001.

STATUTORY AUTHORITY

The new sections are proposed under Transportation Code, §201.101, which provides the Texas Transportation Commission with the authority to establish rules for the conduct of the work of the Texas Department of Transportation, and more specifically, Government Code, §1403.002 and Rider 52 to the department's appropriations for Fiscal Years 2002-2003, which require the commission to adopt rules for the administration of the border colonia access program.

No statutes, articles, or codes are affected by the proposed new sections.

*§15.100. Purpose.*

Senate Bill 1296, 77th Legislature, 2001, requires the Texas Public Finance Authority, in accordance with requests from the Office of the Governor, to issue general obligation bonds and notes in an aggregate amount not to exceed $175 million, and as directed by the department, distribute the proceeds to counties to provide financial assistance for colonia access roadway projects to serve border colonias. The legislation requires the commission to establish a program to administer the use of the proceeds of the bonds and notes. Rider 52 to the department's appropriations for Fiscal Years 2002-2003 requires the department to establish a transportation program to improve access to colonias. The sections under this subchapter set forth the procedures by which a county may apply for assistance under Senate Bill 1296 and Rider 52 and establish criteria by which the commission will select projects.

*§15.101. Definitions.*

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

(1) AASHTO--The American Association of State Highway and Transportation Officials.

(2) Border colonia--A community, located in an eligible county, that is identified as a colonia in the Texas Water Development Board's colonia database.

(3) Border districts--The El Paso, Laredo, Pharr, and Odessa department districts.

(4) Commission--The Texas Transportation Commission.

(5) County road--A road owned and maintained by a county.

(6) Department--The Texas Department of Transportation.

(7) Eligible costs--The cost of constructing, administering, or providing drainage for a project or acquiring materials used in maintaining a project.

(8) Eligible county--A county located in the El Paso, Laredo, or Pharr department districts, and Terrell County, that has adopted the model rules promulgated by the Texas Water Development Board under Water Code, §16.343.

(9) Executive director--The executive director of the department.

(10) Minimum colonia access road standards--Road standards for the applicable transportation facility, as described in the latest editions of appropriate AASHTO design guidelines or in more stringent road standards adopted by a county under Local Government Code, §232.025.

(11) Public road--A road owned and maintained by a municipality, county, or the department.

*§15.102. Eligibility.*

For a project to be eligible for consideration for the program, it must:

(1) be located within an eligible county;

(2) have one terminus at or within a border colonia and one terminus at a public road; and

(3) be designed and constructed by the county or its contractor to minimum colonia access road standards.

*§15.103. Application Procedures.*

(a) The department, through the border district offices, will issue a program call to the eligible counties to prepare an application for each project that a county would like to submit for consideration. The border district offices will have application forms available for the counties.

(b) The department will establish a deadline for applications to be received. In order to be considered for the program call, the application must provide:

(1) a clear and concise description of the work proposed;

(2) an implementation plan, including a schedule of proposed activities and a detailed estimate of project costs;

(3) a map delineating project location and termini; and

(4) documentation addressing the criteria prescribed in §15.104 of this subchapter.

(c) The department will evaluate the applications, and if determined to be in compliance with this section, will submit the applications to the commission for approval under §15.105 of this subchapter.

*§15.104. Project Selection Criteria.*

(a) The commission will consider the following criteria for project selection:

(1) population of the border colonia the project is to serve, based on the latest estimates from the Texas Water Development Board;

(2) condition of current roads, such as the number of existing paved roads in and to the border colonia the project is to serve;

(3) whether the project is on an existing or planned school bus route;

(4) access to other parts of the region, such as the number of roads, paved or unpaved, to the border colonia the project is to serve; and

(5) the number resulting from dividing the border colonia population whose residences abut the project limits by the number of miles of roadway in the project.

(b) Each criterion will be weighted 20 points, for a total possible score of 100. The commission will consider the projects in descending rank order as far as available funding permits.

*§15.105. Apportionment.*

The department will apportion and distribute available funds in the manner described by this section.

(1) The first 50% of available funds will be distributed to a county in proportion to its border colonia population, based on the latest estimates from the Texas Water Development Board. The commission will fund the highest ranked projects as evaluated and scored under §15.104 of this subchapter.

(2) The remaining 50% of available funds will then be distributed to individual counties on a project by project basis. All projects submitted by the counties and not funded under paragraph (1) of this section will be funded in descending rank order as determined under §15.104 of this subchapter as available funding permits.

(3) If a county did not submit sufficient eligible projects to expend funds available under paragraph (1) of this section, the remaining funds will be distributed in accordance with paragraph (2) of this section.

(4) Funds available as a result of a county being prohibited from continued participation in the program under §15.106(e) of this subchapter or because of county reimbursements under §15.106(f) of this subchapter will be distributed in accordance with paragraph (2) of this section.

(5) Projects will be funded based on the project cost estimates provided by a county under §15.103 of this subchapter. Project costs above that estimate are the responsibility of the county. A county may seek additional funds for a project if the department issues subsequent program calls.

*§15.106. Program Administration.*

(a) Agreement. Prior to receiving funds under this program, a county must execute an agreement with the department. The agreement, among other things, will include a commitment by the county to:

(1) place the project on the county road system;

(2) complete any water and wastewater services that are expected to be placed in or across an approved road project right of way prior to constructing the project;

(3) expend funds received only on eligible costs;

(4) comply with all applicable federal, state, and local environmental laws and regulations and permitting requirements;

(5) maintain the road; and

(6) comply with the grant management standards in subsection (c) of this section.

(b) Application costs. Costs incurred in the preparation of applications submitted under §15.103 of this subchapter are not reimbursable with funds received under this program.

(c) Grant management standards. A county receiving funds under this program must:

(1) comply with the Uniform Grant Management Standards promulgated by the Office of the Governor under 1 TAC §§5.141-5.167; and

(2) upon project selection, submit a financial report that shows how it will use the funds to build the project.

(d) Certification. Upon project completion, a county receiving funds must submit a written certification that it has complied with the requirements of this subchapter, including a certification that the project has been constructed in accordance with those requirements.

(e) Compliance. The executive director may:

(1) prohibit a county from participating in the program if the executive director determines that the county has not complied with one or more requirements of this subchapter;

(2) prohibit a county from continuing to participate in the program until such time as the executive director determines that the county has complied with all requirements of this subchapter; or

(3) eliminate a project from participation in the program if the project is not implemented within a reasonable time, as determined by the department in consultation with the county (in the absence of information suggesting that a shorter or longer period is appropriate, three years from the date of the agreement with the department is considered appropriate).

(f) Reimbursement. If a county does not complete a project, the department may seek reimbursement of funds received by the county for that project.

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 October 1, 2001.

TRD-200105890
Richard D. Monroe
General Counsel
Texas Department of Transportation
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 463-8630

♦ ♦ ♦

## SUBCHAPTER J. DESIGN CONSIDERATIONS

### 43 TAC §§15.120 - 15.122

The Texas Department of Transportation proposes new §§15.120-15.122, concerning the consideration of various design factors when developing transportation projects.

EXPLANATION OF PROPOSED NEW SECTIONS

Senate Bill 1128, 77th Legislature, 2001, added Transportation Code, §201.614, requiring the department to consider specified design factors when developing transportation projects that involve the construction, reconstruction, rehabilitation, or resurfacing of a highway, other than a maintenance resurfacing project. Section 201.614 requires the commission to adopt rules to implement that section.

In order to implement the requirements of Transportation Code, §201.614, and to ensure the uniform and consistent development of transportation plans and projects, new §§15.120-15.122 describe how the design factors specified in Transportation Code, §201.614 will be considered during the development of certain transportation projects in which the department has design and construction or funding responsibilities.

New §15.120 describes the purpose of new Subchapter J, Design Considerations, including the implementation of Transportation Code, §201.614.

New §15.121 provides definitions for words and terms used in the new subchapter.

New §15.122 describes how the specified design factors will be considered and assessed as transportation projects are developed in order to provide transportation systems and alternatives that are comfortable, safe, durable, cost-effective, accessible, environmentally sensitive, aesthetically pleasing, and that consider other transportation modes. New §15.122 provides that the design factors will be considered by department districts, and by local governments and metropolitan planning organizations when planning and designing projects that are funded by the department.

As required by Transportation Code, §201.614, the design factors will be considered when developing projects that involve the construction, reconstruction, rehabilitation, or resurfacing of a highway, other than maintenance resurfacing projects. The department and the transportation engineering industry typically categorize projects, other than those on new location, as reconstruction, rehabilitation, restoration, or resurfacing. Transportation Code, §201.614 does not specifically mention restoration projects. However, resurfacing projects, other than maintenance resurfacing projects, would typically be defined by the transportation industry as restoration work. The industry definition of resurfacing typically refers to what Transportation Code, §201.614 calls maintenance resurfacing.

FISCAL NOTE

James Bass, Director, Finance Division, has determined that for each of the first five-years the new sections are in effect, there will be no fiscal implications for state or local governments as a result of enforcing or administering the new sections. The new sections require the consideration of design factors that are currently considered in project development because of requirements of law or prudent engineering practices. There are no anticipated economic costs for persons required to comply with the new sections as proposed.

Robert Kovar, Interim Director, Design Division has certified that there will be no significant impact on local economies or overall employment as a result of enforcing or administering the new sections.

PUBLIC BENEFIT

Mr. Kovar has also determined that for each year of the first five years the new sections are in effect, the public benefit anticipated as a result of enforcing or administering the new sections will be to ensure the uniform and consistent development of transportation plans and projects in order to provide transportation systems and alternatives that are comfortable, safe, durable, cost-effective, accessible, environmentally sensitive, aesthetically pleasing, and that consider other transportation modes. There will be no adverse economic effect on small businesses.

SUBMITTAL OF COMMENTS

Written comments on the proposed new sections may be submitted to Robert Kovar, Interim Director, Design Division, 125 East 11th Street, Austin, Texas 78701-2483. The deadline for receipt of comments is 5:00 p.m. on November 12, 2001.

STATUTORY AUTHORITY

The new sections are proposed under Transportation Code, §201.101, which provides the Texas Transportation Commission with the authority to establish rules for the conduct of the work of the Texas Department of Transportation, and more specifically, Transportation Code, §201.614, which requires the commission to adopt rules to implement that section.

No statutes, articles, or codes are affected by the proposed new sections.

*§15.120. Purpose.*

Transportation Code, §201.614 requires the department to consider various design factors when developing transportation projects that involve the construction, reconstruction, rehabilitation, or resurfacing of a highway, other than a maintenance resurfacing project. This subchapter describes how those design factors will be considered during the development of transportation projects in which the department has design and construction or funding responsibilities.

*§15.121. Definitions.*

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

(1) Construction project--A transportation project in which the primary activities involve building a segment of highway or public road in a new configuration or on a new location.

(2) Department--The Texas Department of Transportation.

(3) District--One of the 25 geographical areas, managed by a district engineer, in which the department conducts its primary work activities, including project development.

(4) Local government--Any county, city, other political subdivision of this state, or special district that has the authority to plan and design a highway or roadway project.

(5) Metropolitan planning organization (MPO)--The forum for cooperative transportation decision making for the metropolitan planning area. The MPO is also the organization that is responsible for carrying out the transportation planning process for the metropolitan area as required by 23 U.S.C. §134.

(6) Reconstruction project--A transportation project in which the primary activities involve rebuilding a segment of highway or public road, usually including realignment or regrading of the existing road, or the addition of through travel lanes or bridge replacement projects.

(7) Rehabilitation project--A transportation project in which the primary activities involve improving the serviceability, extending the service life, and enhancing the safety of a segment of highway or public road but does not include the construction of additional travel lanes other than auxiliary lanes.

(8) Restoration project--A transportation project in which the primary activities involve restoring the pavement structure and riding quality on a segment of highway or public road to its original condition.

(9) Resurfacing project--A project in which the primary activities involve preserving, rather than improving, the structural integrity of the pavement or restoring ride quality, skid resistance or other components of an existing highway or public road.

(10) Transportation Project--The planning, development, design and construction work necessary to construct, reconstruct, rehabilitate or restore a highway or public road that the department has the responsibility to finance or undertake. A project may include, but is not limited to, improvements to a bridge, toll road, transit facility, or high occupancy vehicle lane, or other facilities necessary for an integrated transportation system, but does not include a resurfacing project.

*§15.122. Design Considerations.*

The factors as provided in paragraph (1) of this section will be considered when transportation projects are developed in order to provide transportation systems and alternatives that are comfortable, safe, durable, cost-effective, accessible, environmentally sensitive, aesthetically pleasing, and that consider other transportation modes.

(1) Factors. The department, through a district, local government or MPO, shall consider the following factors when developing transportation projects:

(A) the extent to which the project promotes safety;

(B) the durability of the project;

(C) the economy of maintenance of the project;

(D) the impact of the project on:

*(i)* the natural and artificial environment;

(ii) the scenic and aesthetic character of the area in which the project is located;

(iii) preservation efforts; and

(iv) each affected local community and its economy; and

(E) the access for other modes of transportation, including those that promote physically active communities.

(2) Assessment. The factors provided in paragraph (1) of this section will be assessed when developing transportation projects.

(A) Safety will be considered throughout the project development process. Each type of project will be evaluated, appropriate engineering studies will be completed, and appropriate design guidelines will be utilized with sound engineering judgment in order to accomplish the purpose of that particular transportation project. Safety is integral to properly engineering each project to address the anticipated needs and conditions.

(B) Durability and economy of maintenance will be incorporated into each project as it is developed in order to provide the most cost-effective and reliable products available through engineering study and evaluation. Final selection of products will be based on accepted design practices, specifications, availability of products, testing, and construction industry standards. The appropriate combination of products in each project will provide a project with a reasonably long life and will require reasonable upkeep to preserve its originally intended service life.

(C) The factors listed in paragraph (1)(D) of this section are all factors considered in the environmental review and public involvement process as prescribed in Chapter 2, Subchapter C of this title (relating to Environmental Review and Public Involvement for Transportation Projects) that is an integral part of the development of each project.

(D) Access for other modes of transportation will be considered during the project development process by developing plans and projects that contain, where appropriate, interconnections with other transportation facilities, including bicycle transportation facilities, pedestrian walkways, and trails.

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 October 1, 2001.

TRD-200105891
Richard D. Monroe
General Counsel
Texas Department of Transportation
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 463-8630

♦ ♦ ♦

## CHAPTER 21. RIGHT OF WAY
## SUBCHAPTER A. LAND ACQUISITION PROCEDURES

**43 TAC §§21.1, 21.2, 21.6, 21.7, 21.10, 21.11, 21.13, 21.15**

The Texas Department of Transportation proposes amendments to §§21.1, 21.2, 21.6, 21.7, 21.10, 21.11, 21.13, and 21.15, concerning land acquisition procedures.

EXPLANATION OF PROPOSED AMENDMENTS

The amendments are required due to changes in state and federal law. The amendments will bring the land acquisition regulations up to date and into compliance with current law, including the name change of the former State Highway and Public Transportation Commission to the Texas Transportation Commission.

The amendments to §21.1 expand the application of this section to all state highways, as right of way acquisition procedures and department involvement are basically the same for both interstate and other state highways. The amendment allows the acquisition of right of way to be accomplished either directly by the staff of the department or by the use of contracted right of way acquisition providers as now authorized by the recently adopted amendments to Title 43, Texas Administrative Code, Chapter 9, Subchapter F. Additionally, this amendment clarifies that local public entities (municipalities and counties) may also acquire right of way for the department by contractual agreement.

Section 21.2 is amended to reflect a name change from the State Highway and Public Transportation Commission to the Texas Transportation Commission.

The amendments to §21.6 expand the alternative procedures for verifying title information when title insurance policies cannot be utilized. This allows other department staff members to verify titles from information provided by abstract companies when department staff attorneys are not available. This amendment is necessary because very few of the department's districts have staff attorneys.

The amendments to §21.7 add a reference to Chapter 1, Subchapter G of this title (relating to Donations) and include provisions required both by Subchapter G and Government Code, Chapter 575, regarding department action required to accept a donation.

The amendments to §21.10 add procedures and requirements to provide a copy of an appraisal to the landowner at the time an initial offer is made, as required by a revision to the Property Code. Additionally, to bring this regulation into complete compliance with the Code of Federal Regulations, Title 49, Subtitle A, Subpart B, (Real Property Acquisition) §24.102 (Basic Acquisition Policies), revised procedures are included regarding the proper amounts to deposit into the registry of the court when possession of property is required before final judgment is obtained in an eminent domain court proceeding.

Section 21.11 is amended to more precisely describe the type of documentation provided to a local public entity when that entity is requested to directly acquire right of way for the department, with such documentation to be property legal descriptions plus right of way maps. The former wording could have been misunderstood, particularly the word "plat," as the department is not required to follow formal platting and replatting requirements concerning highway right of way acquisitions. Also, the former designation of the State Highway and Public Transportation Commission has been changed to the Texas Transportation Commission.

The amendments to §21.13 remove the word "confidential" because the amendments in §21.10 of this chapter and Property Code, §21.0111 now require the department to provide to the property owner a copy of the appraisal upon which the amount of the offer is based. A broader description of what constitutes an appraisal has been added in a parenthetical statement because department procedures and federal regulations allow various methods for valuing a property, some of which are shorter or more informal such as the procedures listed in the parenthetical statement.

The amendments to §21.15 change the designation of the type of contracts utilized for appraisers, technical experts, and estimators, from "personal" service contracts to "professional" service contracts. This amendment conforms with Government Code, Chapter 2254, Subchapter A and recently amended 43 TAC Chapter 9, Subchapter F, which provides the procedures for handling such professional service contracts.

FISCAL NOTE

James Bass, Director, Finance Division, has determined that for each of the first five years the amendments are in effect, there will be no fiscal implications for state or local governments as a result of enforcing or administering the amendments. There are no anticipated economic costs for persons required to comply with the sections as proposed.

John P. Campbell, Director, Right of Way Division, has certified that there will be no significant impact on local economies or overall employment as a result of enforcing or administering the amendments.

PUBLIC BENEFIT

Mr. Campbell has also determined that for each year of the first five years the sections are in effect, the public benefit anticipated as a result of enforcing or administering the amendments will be to further the department's mission to provide an efficient and fair process of acquiring right of way and in negotiating with landowners in accordance with state and federal law and regulations and also in the selection of right of way service providers, appraisers, and technical experts. There will be no adverse economic effect on small businesses.

SUBMITTAL OF COMMENTS

Written comments on the proposed amendments may be submitted to John P. Campbell, Director, Right of Way Division, 125 East 11th Street, Austin, Texas 78701-2483. The deadline for receipt of comments is 5:00 p.m. on November 12, 2001.

STATUTORY AUTHORITY

The amendments are proposed under Transportation Code, §201.101, which provides the Texas Transportation Commission with the authority to establish rules for the conduct of the work of the Texas Department of Transportation.

No statutes, articles, or codes are affected by the proposed amendments.

*§21.1. Responsible Entity [~~Interstate Highways~~].*

Adequate right-of-way to accommodate the approved design of projects on designated state [~~interstate~~] highways may be [~~is~~] acquired directly by the staff of the department, by the utilization of the services of a right of way acquisition provider under contract with the department in accordance with Chapter 9, Subchapter F of this title (relating to Contract Management), or directly by counties or cities in accordance with §21.11 and §21.12 of this subchapter. If [~~except that where~~] eminent domain proceedings are necessary, [~~such~~] acquisition is handled by the Office of the Attorney General unless a specific acquisition contract or agreement with a county or city provides that the county or city will handle eminent domain proceedings.

*§21.2. Controlled Access Highways.*

For highways officially designated as controlled access highways by the Texas [~~State Highway and Public~~] Transportation Commission, right-of-way is acquired with access between abutting properties and the highway facility permitted and/or denied in accordance with the approved design of the projects.

*§21.6. Use of Abstract Plant Facilities.*

(a) Whenever title policies cannot be obtained in the normal procedure, the determination of ownership and title defects, if any, are made through the use of abstract plant facilities under contract to the state. The contract may be by the hour or by the parcel depending on departmental needs and preference of the owner of the abstract plant facility. The title examinations may be [~~are~~] made by licensed staff attorneys using the abstract facilities or by the abstract company providing a title run sheet directly to the department to be reviewed by other staff of the department.

(b) Bid proposals are taken from each abstractor in the county who is willing and able to furnish the desired services and forwarded to Austin for administrative decisions as to acceptance or rejection.

*§21.7. Donation of Real Property.*

If accepted by the department in accordance with Chapter 1, Subchapter G, of this title (relating to Donations), a [~~A~~] person whose real property is being acquired by the department for a highway project may make a gift or donation of the [~~such~~] property, or any part of the property. The department will inform the owner of the owner's [~~thereof, after such person has been fully informed of his~~] right to receive just compensation for the [~~his~~] property.

*§21.10. Negotiations.*

(a) Every reasonable effort will be made to acquire real property by negotiation and the full amount established as just compensation will be offered for the [~~such~~] property. At the time an offer to purchase is made, an [~~An~~] owner of real property will be provided with a copy of all existing appraisal reports that were used in determining the final valuation offer in accordance with Property Code, Section 21.0111 [~~written statement of, and summary of the basis for the amount established as just compensation~~]. Where appropriate, the just compensation for the real property acquired and for damages to remaining real property shall be separately stated. No owner shall be required to surrender possession of real property before:

(1) payment of the agreed purchase price;

(2) in the case of condemnation, the amount of compensation stated in the final judgment is paid to the owner or deposited with a court for the benefit of the owner; or

(3) in the case of condemnation when possession is required by the department prior to a final judgment being entered, the department has deposited with the court, for the benefit of the owner, the amount of a special commissioners' award or the amount of the department's approved appraisal of the property, whichever is greater.

(b) In the case of condemnation where the department does not take possession until after a final judgment of the court has been entered, the amount of compensation paid to the owner of the property or deposited with a court for the benefit of the owner shall be the amount of compensation stated in the final judgment in the condemnation proceeding for the property. [~~No owner shall be required to surrender possession of real property before payment of the agreed purchase price, or deposit with a court the amount of the award of compensation in a condemnation proceeding of such property.~~] To the greatest extent practicable, no person lawfully occupying real property shall be required to move without at least 90 days written notice of the date by which the [~~such~~] move is required.

*§21.11. Requests to Counties and Cities for Acquisition of Right-of-Way.*

The appropriate district engineer [~~or engineer-manager~~] is authorized to furnish to the applicable county or city the property legal descriptions and right-of-way maps of land or right-of-way [~~plats or field notes of right-of-way or land~~] deemed necessary or convenient for any road or highway to be constructed, reconstructed, maintained, widened, straightened, or lengthened as a part of the state highway system. The property legal descriptions and right-of-way maps [~~Said plats or field notes~~] are prepared to accommodate the approved design of projects as authorized by the Texas [~~State Highway and Public~~] Transportation Commission.

*§21.13. Highway Right-of-Way Values.*

Prior to the making of offers to purchase right-of-way for highway purposes by the department, approved values are determined based upon [~~confidential~~] appraisals (including short form appraisals, memorandums of value, or opinions of value) of the real property to be acquired. The owner or the owner's [~~his~~] designated representative is given the opportunity to accompany the appraiser during the inspection of the property being appraised.

*§21.15. Employment of Real Estate Appraisers, Technical Experts, and Estimators.*

The services of real estate appraisers and technical experts or estimators are obtained by the department on the basis of professional [~~personal~~] service contracts in accordance with Chapter 9, Subchapter F of this title (relating to Contract Management).

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 October 1, 2001.

TRD-200105892
Richard D. Monroe
General Counsel
Texas Department of Transportation
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 463-8630

♦ ♦ ♦

# CHAPTER 25. TRAFFIC OPERATIONS
# SUBCHAPTER B. PROCEDURES FOR ESTABLISHING SPEED ZONES

## 43 TAC §25.21

The Texas Department of Transportation proposes amendments to §25.21, concerning the department's procedures for establishing speed zones.

EXPLANATION OF PROPOSED RULE

These amendments are proposed under Transportation Code, §545.353, subsections (h) and (i), as added by House Bill 299, 77th Legislature, 2001, which allows the Texas Transportation Commission (commission) to establish 75 mile per hour daytime speed limits on certain portions of the state highway system. Speed limits established under this amended section will apply to passenger vehicles, but will not apply to trucks (other than light trucks and light trucks pulling a trailer), truck tractors, trailers, and semitrailers.

House Bill 299 allows the commission to establish such a speed limit on portions of the state highway system located in counties with a population density of less than 10 persons per square mile.

The amendment to §25.21(b)(4)(B) adds the reference to Transportation Code, §545.353, subsections (h) and (i), which allow the department to establish a 75 mile per hour maximum daytime speed limit in certain counties. This amended section states which counties are eligible for this speed limit based on the population limitations contained in the statute. In order to establish such a speed limit, the commission must find that it is safe and reasonable. The amended section also states that a 75 mile per hour speed limit does not apply to large trucks.

FISCAL NOTE

Mr. James Bass, Director, Finance Division, has determined that for each of the first five-years the amendment is in effect, there will be minimal fiscal implications to state government as a result of enforcing or administering the amendment. Creation of any new speed limits as a result of this section will be performed using existing department staff. Although any new speed limit will require new signage, the department expects these costs to be minor. There is no anticipated fiscal impact on local governments. There are no anticipated economic costs to persons required to comply with the amended section as proposed.

Carlos A. Lopez, P.E., Director, Traffic Operations Division, has certified that there will be no significant impact on local economies or overall employment as a result of enforcing or administering the proposed amended section.

PUBLIC BENEFIT

Mr. Lopez has also determined that for each year of the first five years the proposed amended section is in effect, the public benefit anticipated as a result of enforcing or administering the amended section will be to allow higher maximum speed limits on certain portions of the state highway system in the state's more sparsely populated counties. This higher speed limit will more closely reflect actual operating conditions on the highways on which it is posted. There will be no adverse economic effect on small businesses.

SUBMITTAL OF COMMENTS

Written comments on the proposed amendment may be submitted to Carlos A. Lopez, P.E., Director, Traffic Operations Division, 125 East 11th Street, Austin, Texas 78701-2483. The deadline for receipt of comments is 5:00 p.m. on November 12, 2001.

STATUTORY AUTHORITY

The amendments are proposed under Transportation Code, §201.101, which provides the Texas Transportation Commission with the authority to establish rules for the conduct of the work of the Texas Department of Transportation, and more specifically, Transportation Code, §545.353 subsections (h) and (i), which allows the Texas Transportation Commission to establish a 75 mile per hour daytime speed limit on certain portions of the state highway system in certain counties.

No other statutes, articles, or codes are affected by these proposed amendments.

*§25.21. Introduction.*

(a) (No change.)

(b) Background.

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

(4) Authority to set speed zones.

(A) Transportation Code, §545.353, authorizes the commission to alter maximum speed limits on highway routes both within and outside of cities, provided the Procedures for Establishing Speed Zones are followed.

(B) Transportation Code, §545.353, subsections (h) and (i), address the Texas Transportation Commission's authority to establish a daytime speed limit of 75 mile per hour on a portion of the state highway system.

*(i)* The commission may establish such a speed limit in counties with a population density of less than 10 persons per square mile. Counties that are currently eligible for this higher maximum daytime speed limit are Andrews, Archer, Armstrong, Bailey, Baylor, Borden, Brewster, Briscoe, Brooks, Carson, Castro, Cochran, Coke, Coleman, Collingsworth, Concho, Cottle, Crane, Crockett, Crosby, Culberson, Dallam, Dickens, Dimmit, Donley, Duval, Edwards, Fisher, Floyd, Foard, Gaines, Garza, Glasscock, Goliad, Hall, Hamilton, Hansford, Hardeman, Hartley, Haskell, Hemphill, Hudspeth, Irion, Jack, Jeff Davis, Jim Hogg, Kenedy, Kent, Kimble, King, Kinney, Knox, La Salle, Lipscomb, Loving, Lynn, Martin, Mason, McCullough, McMullen, Menard, Mills, Motley, Ochiltree, Oldham, Pecos, Presidio, Reagan, Real, Reeves, Roberts, San Saba, Schleicher, Shackelford, Sherman, Sterling, Stonewall, Sutton, Swisher, Terrell, Throckmorton, Upton, Wheeler, Winkler, Yoakum and Zavala.

*(ii)* The department will reevaluate which counties are eligible for such a speed limit upon the release of each decennial federal census of the population.

*(iii)* In order to establish a 75 mile per hour daytime speed limit in an eligible county, the commission must determine that a 75 mile per hour speed limit is safe and reasonable.

*(iv)* A 75 mile per hour speed limit established under this section does not apply to trucks (other than light trucks and light trucks pulling a trailer), truck tractors, trailers, and semitrailers.

(C) [~~(B)~~] The altering of the general statewide maximum speed limits to fit existing traffic and physical conditions of the highway constitutes the basic principle of speed zoning.

(D) [~~(C)~~] Transportation Code, §§545.355 and 545.356 give counties and cities the same authority within their respective jurisdictions. The law also provides that any speed zone on highway routes in cities established by commission minute order will supersede any conflicting zone set by city ordinance or resolution.

(E) [~~(D)~~] Except in very unusual circumstances, the zoning on state highway routes within cities should only be set by city ordinance or resolution based upon the recommendations of TxDOT. The usual practice, even for speed zones established by city ordinance or resolution, is for TxDOT to make the necessary speed studies and recommend the most appropriate zoning to the city. Cities that have a traffic engineering staff may also make speed studies on state-maintained highways and recommend proper zoning. The procedure is permissible so long as TxDOT is afforded an opportunity to review and approve the recommended city zoning.

(F) [~~(E)~~] County commissioner courts and governing bodies of incorporated cities and villages may alter maximum prima facie speed limits on roadways under their jurisdiction in accordance with the provisions of Transportation Code, §§545.355 and 545.356 respectively. However, alteration of maximum prima facie speed limits on any designated or marked roadway of the state highway system, even within the corporate limits of a city, typically requires an engineering and traffic investigation in accordance with §25.23 of this title (relating to Speed Zone Studies), and the approval of TxDOT.

(G) [~~(F)~~] A county that increases the prima facie speed limit on a county road or highway is also required to conduct an engineering and traffic investigation. However, for a county road or highway outside the limits of the right of way of an officially designated or marked highway or road on the state highway system, the county commissioners court may declare a lower speed limit of not less than 30 miles per hour, if the commissioners court determines that the prima facie speed limit on the road or highway is unreasonable or unsafe.

(H) [~~(G)~~] County authority does not extend to any segment of the state highway system; however, the commissioners court of a county, by resolution, may request the commission to determine and declare a reasonable and safe prima facie speed limit that is lower than a speed limit established by Transportation Code, §545.352, on any part of a farm-to-market or ranch-to-market road without improved shoulders located in that county.

(I) [~~(H)~~] The commission shall give consideration to local public opinion and may determine and declare a lower speed limit on any part of the road without an engineering and traffic investigation, but the commission must use sound and generally accepted traffic engineering practices in determining and declaring the lower speed limit. Sound and generally accepted engineering practices for these FM and RM roadways without improved shoulders are described in §25.23(d) of this title.

(J) [~~(I)~~] This is different from the authority of cities, who may exercise concurrent authority subject only to commission override. In exercising their authority, cities must base any speed zones on engineering and traffic investigations, notwithstanding the type of road or street and whether the state highway system is involved.

(K) [~~(J)~~] The authority of the Texas Turnpike Authority, regional tollway authorities, and Commanding Officer of a United States Military Reservation to alter the speed limits are addressed in Texas Transportation Code, §§545.354 and 545.358. These decision making authorities are required to follow the speed zone procedures as adopted by the department when altering speed limits on off-system turnpikes or on-system highways within the confines of a military reservation.

(5) - (6) (No change.)

(c) (No change.)

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 October 1, 2001.

TRD-200105893
Richard D. Monroe
General Counsel
Texas Department of Transportation
Earliest possible date of adoption: November 11, 2001
For further information, please call: (512) 463-8630

♦ ♦ ♦

# 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 16. ECONOMIC REGULATION

### PART 2. PUBLIC UTILITY COMMISSION OF TEXAS

### CHAPTER 26. SUBSTANTIVE RULES APPLICABLE TO TELECOMMUNICATIONS SERVICE PROVIDERS

### SUBCHAPTER R. PROVISIONS RELATING TO MUNICIPAL REGULATION AND RIGHTS-OF-WAY MANAGEMENT

**16 TAC §26.469**

The Public Utility Commission of Texas has withdrawn from consideration proposed new §26.469 which appeared in the April 6, 2001, issue of the *Texas Register* (26 TexReg 2613).

Filed with the Office of the Secretary of State on September 25, 2001.

TRD-200105800
Rhonda G. Dempsey
Rules Coordinator
Public Utility Commission of Texas
Effective date: September 25, 2001
For further information, please call: (512) 936-7308

♦ ♦ ♦

## TITLE 22. EXAMINING BOARDS

### PART 24. TEXAS BOARD OF VETERINARY MEDICAL EXAMINERS

### CHAPTER 573. RULES OF PROFESSIONAL CONDUCT

### SUBCHAPTER G. OTHER PROVISIONS

**22 TAC §573.74**

The Texas Board of Veterinary Medical Examiners has withdrawn from consideration proposed new §573.74 which appeared in the July 13, 2001, issue of the *Texas Register* (26 TexReg 5196).

Filed with the Office of the Secretary of State on September 26, 2001.

TRD-200105837
Ron Allen
Executive Director
Texas Board of Veterinary Medical Examiners
Effective date: September 26, 2001
For further information, please call: (512) 305-7555

♦ ♦ ♦

# 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 agencyadopts the section with changes to the proposed text, the proposal will be republished with the changes.

## TITLE 1. ADMINISTRATION

## PART 4. OFFICE OF THE SECRETARY OF STATE

### CHAPTER 87. NOTARY PUBLIC

### SUBCHAPTER B. REJECTION AND REVOCATION

#### 1 TAC §87.43

The Office of the Secretary of State adopts an amendment to §87.43, concerning "good cause" without changes to the proposed text as published in the August 24, 2001, issue of the *Texas Register* (26 TexReg 6200).

The amendment to §87.43 pertains to "good cause" as that phrase relates to the rejection of an application or the revocation of a notary public commission. The purpose of the amendment is to conform §87.43 to amendments to Chapter 406 of the Government Code that were made by the 77th Texas Legislature in House Bill 3134.

No comments were received concerning the proposed amendment.

The amendment is adopted under the Texas Government Code, §2001.004 (1) and the Notary Public Act, Texas Government Code, §406.023(a) which provide the Secretary of State with the authority to prescribe and adopt rules.

The amendment affects the Texas Government Code, §406.009 and §406.017.

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 September 28, 2001.

TRD-200105881
Geoffrey S. Connor
Assistant Secretary of State
Office of the Secretary of State
Effective date: October 18, 2001
Proposal publication date: August 24, 2001
For further information, please call: (512) 475-0775

♦ ♦ ♦

## PART 15. TEXAS HEALTH AND HUMAN SERVICES COMMISSION

### CHAPTER 355. MEDICAID REIMBURSEMENT RATES

### SUBCHAPTER J. PURCHASED HEALTH SERVICES

### DIVISION 28. PHARMACY SERVICES: REIMBURSEMENT

#### 1 TAC §355.8541

The Health and Human Services Commission (HHSC) adopts the repeal of §355.8541 concerning reimbursement of product cost in the Vendor Drug Program (VDP), concerning the industry sources used to estimate the cost of product acquisition for providers of Medicaid outpatient pharmacy services, and how these sources are used to arrive at the HHSC's best estimate of the provider's acquisition costs. The rule specifies mark-ups and discounts from published pricing data that result from the methodology that is used to price products. The rule is repealed without changes as published in the June 22, 2001, issue of the *Texas Register* (26 TexReg 4576).

The repeal is adopted under the Human Resources Code, §32.021 and the Texas Government Code, §531.021, which provide the Health and Human Services Commission with the authority to adopt rules to administer the State's medical assistance program.

The repealed rule affects the Human Resources Code, Chapter 32, and the Texas Government Code, Chapter 531.

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 October 1, 2001.

TRD-200105941
Marina S. Henderson
Executive Deputy Commissioner
Texas Health and Human Services Commission
Effective date: October 21, 2001
Proposal publication date: June 22, 2001
For further information, please call: (512) 424-6576

♦ ♦ ♦

**1 TAC §355.8541**

The Health and Human Services Commission (HHSC) adopts new §355.8541 concerning reimbursement of product cost in the Vendor Drug Program (VDP). Currently, the rule describes the industry sources used to estimate the cost of product acquisition for providers of Medicaid outpatient pharmacy services, and how these sources are used to arrive at the HHSC's best estimate of the provider's acquisition costs. The current rule specifies mark-ups and discounts from published pricing data that result from the methodology that is used to price products. The new section eliminates the specific percentages. Additional market resources that may be used when determining prices for outpatient drugs are added. The new rule is adopted with the addition of a definition section, and with changes from the proposed text as published in the June 22, 2001, issue of the *Texas Register* (26 TexReg 4576).

As a result of adopting these new policies, HHSC will be able to use percentages that more accurately reflect current market practices in determining product cost reimbursement for the VDP, to allow more timely response to market fluctuations in the product cost area, and to use all appropriate market sources in determining these costs in the future. Use of these resources will allow more accurate estimates of the actual cost of the products dispensed in the VDP and better meet the requirements contained in federal regulations (42 CFR, §447.331) concerning estimating drug product acquisition costs.

The following comments were received during the comment period and at the public hearing held on July 12, 2001. Following each comment is the Commission's response to the comments. One change was made as the result of these comments. Also, a definition section was added.

Comment: Several commentors expressed concern that the rules were vague and that their application could therefore be arbitrary.

Response: While the Commission disagrees with this comment, we are including a new definition section in the rule which defines several terms about which specific concerns were expressed.

Comment: In a comment similar to the previous comment, several commentors expressed concern that pharmacies would be unable to forecast costs and determine the pharmacy's ability to participate under Medicaid reimbursement if the percentages were removed from the rules.

Response: Prior to September 1, 1997, the general reimbursement percentages were not contained in the rules. They were however sent to participating pharmacies as part of the letter sent whenever there was a reimbursement change. Under the new rule, these letters would be sent after public comment was received and considered and a new set of reimbursement percentages was implemented. Additionally, actual reimbursement amounts for all covered drugs will continue to be sent to participating pharmacies on microfiche and displayed on the VDP website.

Comment: Several commentors were concerned that the reference to wholesalers' profits in Section 355.8541 (2) (E) had been left out of the rule and that that would make determinations of Wholesale Estimated Acquisition Costs unrealistic.

Response: The Commission agrees with this concern. Omission of the reference to wholesalers' profits was an unintentional oversight.

Comment: With regard to Section 355.8541 (2) (E), commentors were concerned about price updates not being made timely because the rule states that "market conditions will be examined at least every two years." They believed that prices would therefore be updated no more often than every two years.

Response: The Commission acknowledges this concern. However, the commitment to reexamine market conditions applies to changes in general reimbursement percentages rather than the routine price updates that are performed by staff as price change information is received from manufacturers. There will be no change in price update activities, which currently occur daily, and VDP staff will continue to be responsive to concerns that individual product prices are not available to pharmacies in the marketplace.

Comment: Several commentors noted that acquisition costs vary among pharmacies and expressed concern that some pharmacies would be unable to buy the drugs at the prices determined using any new percentages.

Response: The Commission acknowledges that product acquisition costs may vary among pharmacies. This is being taken into account in the acquisition cost audits that are currently underway. The sample of pharmacies is divided into several different types and locations of pharmacies. Additionally, product reimbursement determinations made as a result of these audits, like determinations made from previous audits will not be made based on the lowest available prices. Prices in the Vendor Drug Program have always been set based on the necessity to cover the costs of a prudent and efficient provider of Medicaid services. In order to ensure continued Statewide coverage for VDP recipients, this target will continue to be used when setting general product cost reimbursement percentages.

Comment: One commentor made several suggestions for other kinds of cost containment measures that could be undertaken instead of lowering product pricing to reflect our best estimates of pharmacy acquisition costs, assuming current audits indicate such reductions are appropriate.

Response: The Commission appreciates the suggestions for additional program changes that might save money in drug waste and inappropriate prescribing. However, the State is required by federal regulation to make its best estimate of acquisition costs, and the proposed rules will allow us more latitude to ensure that these determinations are made timely and as accurately as market resources will allow. Also, implementation of suggestions regarding discontinuing coverage of certain outpatient drug products or closing the formulary would place the State in violation of 42 USC, Section 1396 r-8. This section of federal law, promulgated as a result of provisions in the Omnibus Budget Reconciliation Act of 1990, provides that states must cover all products defined as covered outpatient drugs in order to be eligible for drug rebates under the Law. Additionally, cost containment initiatives that may be considered do not alter our responsibility to make appropriate adjustments to product reimbursement as market changes that affect pharmacy acquisition are recognized.

Comment: Several Commentors suggested we not change these rules until the dispensing expense is updated.

Response: The Commission disagrees. There is no financial impact from adoption of these rules as no change will be made to the general reimbursement percentages until actual audit information has been examined and public comment received on those findings. Therefore there is no reason to delay adoption of these rules, which merely allow the Commission more flexibility to use all appropriate market information and make more timely determinations of costs in compliance with 42 CFR, Sections 447.301 and 331. The Commission is working with industry regarding appropriate methods for making adjustments to future dispensing fees.

Comment: Commentors expressed confusion over the lack of a fiscal impact, since an earlier proposal had shown a fiscal impact.

Response: The original proposal for changes to this rule also included a proposal for an interim reimbursement adjustment to take effect at the same time as these rules. That proposal was withdrawn, and no adjustment is planned under these rules prior to examining the results of audits that are currently in progress.

Comment: Chain pharmacy representatives expressed their concern with the Central Purchasing Arrangement (CPA) component of the reimbursement policy in Section 355.8541 (2) ( C). Under this policy, reimbursement for providers participating in CPAs may be less than for providers who do not participate in these arrangements.

Response: The current audits will determine if pharmacies using a CPA continue to be able to buy products more economically than other providers. Should the audits find that these differences no longer exist, pricing for products will be adjusted to reflect actual purchasing abilities. For example, should the audits determine that CPA providers now buy certain products, or the majority of products, at the same price as non-CPA pharmacies, the reimbursement for these pharmacies will be identical for these products. However, should audits indicate that there are still significant differences in prices between these arrangements, these will continue to be reflected in our published reimbursement amounts.

Comment: Several commentors wanted the Commission to continue to base reimbursement on AWP.

Response: Vendor Drug reimbursement has not been based solely on AWP since 1985. There is no intention to abandon any of the reference prices we now use, including AWP, in determining general reimbursement percentages. Under these rules, it will still be possible to express these general reimbursement percentages in terms of AWP - or WAC + some amount. These rules allow the Commission more flexibility in determining what those amounts should be based on additional information from manufacturers, wholesalers and other pricing sources in the marketplace.

Comment: Commentors expressed concern that there would be inadequate public notice of adjustments and that the rule allowed retroactive adjustments based on the referenced audits.

Response: The rule specifies that a public hearing will be held to receive comment on proposed changes to general reimbursement percentages derived under these rules. In addition, changes to general reimbursement percentages will result from market based research that will include audits of pharmacies' invoices and other documentation, discussions with pharmacy representatives, or both. At all stages of the reimbursement determinations, pharmacies will have the ability to comment and present information that will be considered in the final reimbursement determinations. Additional pharmacy industry information will be sought, along with other stakeholder input, at regular public meetings held by the commission. The concern with retroactive adjustments may result from confusion between audits performed to verify actual pharmacy acquisition costs and compliance audits performed to discover overpayments to individual providers. Both types of audits are performed by audit staff, but for different purposes. General reimbursement in the Vendor Drug Program has never been reduced retroactively based on acquisition cost audits. Recoupments are only requested when overpayments are determined during routine compliance audits or in cases where fraud or abuse is discovered. The rules dealing with compliance audits are contained in another section of the Texas Administrative Code and no change is being made to those rules.

Comment: The Coalition of Long Term Care Pharmacies expressed concern about changing the reimbursement for drug product costs without making changes in the dispensing fee. They asked numerous questions that relate to whether differential fees or EACs would be developed for different types of pharmacies.

Response: See the response to comment #6 with regard to dispensing fees. The current audits are sampling pharmacies of all types and in both urban and rural locations in Texas to determine if significant differences in EACs exist among the various pharmacy groups. If such differences do exist, different reimbursements for different types of pharmacies may be proposed at the public hearing that will be held regarding new reimbursement percentages.

Comment: With regard to Section 355.8541(3) (A), there was some concern about reimbursement for Over the Counter (OTC) or non-legend drugs. Commentors believed that there would be no "fee" for provision of these drugs.

Response: There has been no change in the policy regarding reimbursement for OTC products. OTC products are reimbursed at product cost + 50% of the product cost, with the result not to exceed the usual product cost + fee determination. While the rule states that no dispensing fee is added to the cost of the OTC product, the 50% or usual fee determination limitation yields an add-on for the dispensing of OTC products. The amount added on may or may not be equal to the fee for a similarly priced legend drug, but it cannot exceed that amount.

Comment: Several comments were made relative to reimbursement components that are more appropriately addressed in determinations of a reasonable fee. These included comments that labor costs have increased 18% since the last determination of a fee in 1997; that the rule as proposed does not pay a pharmacy for costs involved to obtain, transport or store the products; and that there is not adequate provision for periodic re-evaluation of the dispensing fee.

Response: All these comments will be addressed in discussions of dispensing fee rules and reimbursements that are currently being planned. While the Commission is aware that reimbursement components cannot be considered entirely separate from each other, comments that address the fee component cannot properly be addressed as part of this rulemaking.

The new rule is adopted under the Human Resources Code, §32.021 and the Texas Government Code, §531.021, which provide the Health and Human Services Commission with the authority to adopt rules to administer the State's medical assistance program.

The adopted rule affects the Human Resources Code, Chapter 32, and the Texas Government Code, Chapter 531.

*§355.8541. Legend and Nonlegend Medications.*

For all medication, legend and non-legend, covered by the Vendor Drug Program and appearing in the Texas Drug Code Index (TDCI) and updates, the following requirements must be met.

(1) Reimbursement. A pharmaceutical provider is reimbursed based on the lesser of:

(A) the HHSC's best estimate of acquisition cost (EAC) plus the HHSC's currently established dispensing fee per prescription; or

(B) the usual and customary price charged the general public.

(2) Estimated acquisition cost (EAC).

(A) EAC is defined as:

*(i)* wholesale estimated acquisition cost (WEAC);

*(ii)* direct estimated acquisition cost (DEAC), according to the pharmacist's usual purchasing source and the pharmacist's usual purchasing quantity; or

*(iii)* maximum allowable cost (MAC) for multi-source drugs.

(B) EAC is verifiable by invoice audit conducted by the HHSC to include necessary supporting documentation that will verify the final cost to the provider.

(C) All drug purchases through a central purchasing agreement or from a central purchasing entity must be billed to the HHSC as warehouse purchases.

(D) The WEAC is established by the HHSC using market sources, which include, but are not limited to:

*(i)* the current Redbook;

*(ii)* Redbook Update;

*(iii)* First Databank;

*(iv)* First Alert; or

*(v)* reported manufacturer pricing.

(E) The WEAC may not exceed wholesaler cost, as supplied by the drug manufacturers plus an amount representing wholesaler operating costs and profits under current market conditions. Market conditions will be examined at least every two years. Market conditions will be determined from information supplied to the department by reliable sources, which include, but are not limited to the manufacturer, the wholesaler, and contracted providers. Exceptions to general pricing determinations may be made on certain drugs and/or drug categories based on information from these same market sources.

(F) The DEAC is established by the HHSC using direct price information supplied by drug manufacturers. Providers are reimbursed only at the DEAC on all drug products that are available from select manufacturers/distributors who actively seek and encourage direct purchasing. The TDCI is used as the reference for drugs included in the scope of benefits and for allowable package sizes. No acquisition cost is billed to the HHSC for samples dispensed.

(3) Nonlegend drugs.

(A) Reimbursement for nonlegend drugs is based on the lesser of:

*(i)* the usual and customary price charged to the general public; or

*(ii)* EAC, plus 50% of the EAC.

(B) No dispensing fee is added to the price of nonlegend drugs, and 50% of the EAC may not exceed the assigned dispensing fee.

(4) Public Hearing. Notice of a public hearing to receive comments on proposed changes to general pricing determinations derived under these rules shall be published in the Texas Register.

(5) Definitions. As used in the previous section, these terms shall be defined as follows:

(A) Reported Manufacturer Price - Information on pricing submitted to VDP by the manufacturer, including Average Wholesale Price, Average Manufacturer Price, wholesaler costs, direct prices and institutional or contract prices.

(B) Reliable Sources - Sources including other state/federal agencies and pricing services, as well as verifiable reports by contracted pharmacists and VDP field staff.

(C) Market Conditions - Conditions within the overall retail and wholesale pharmacy drug market place.

(D) Wholesaler Costs -- The net cost of a product to a drug wholesaler or distributor.

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 October 1, 2001.

TRD-200105942
Marina S. Henderson
Executive Deputy Commissioner
Texas Health and Human Services Commission
Effective date: October 21, 2001
Proposal publication date: June 22, 2001
For further information, please call: (512) 424-6576

♦ ♦ ♦

# TITLE 16. ECONOMIC REGULATION

## PART 2. PUBLIC UTILITY COMMISSION OF TEXAS

### CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS

### SUBCHAPTER E. CERTIFICATION, LICENSING AND REGISTRATION

#### 16 TAC §25.101

The Public Utility Commission of Texas (commission) adopts an amendment to §25.101 relating to Certification Criteria with changes to the proposed text as published in the June 15, 2001 *Texas Register* (26 TexReg 4358). The amendment is necessary to establish criteria for the commission to consider in its evaluation of applications for approval of electric transmission lines. The amendment also removes references to Chapter 23, §25.171, and makes other non-substantive changes. This amendment was adopted under Project Number 24101.

A public hearing on this amendment was held at commission offices at 10:00 a.m. on Tuesday, August 7, 2001. Representatives from the American Electric Power Company (AEP) on behalf of Central Power and Light Company, Southwestern Electric Power Company, and West Texas Utilities Company; Brazos Electric Power Cooperative, Inc. (Brazos); East Texas Electric Cooperative, Inc. (ETEC); South Texas Electric Cooperative, Inc. (STEC); Texas Farm Bureau (Farm Bureau); and TXU Electric Company (TXU) attended the hearing and provided comments.

Written comments were received from AEP, Brazos, El Paso Electric Company (El Paso), ETEC, FPL Energy, LLC (FPLE), Lower Colorado River Authority (LCRA), Pedernales Electric Cooperative (PEC), Reliant Energy HL&P (Reliant), STEC, Southwestern Public Service Company (SPS), Texas Electric Cooperatives, Inc. (TEC), Farm Bureau, TXU, and independent generators; Dynegy Power Corp., Calpine Corporation, and Tenaska Inc., which filed comments jointly.

The commission requested comments on the question: *Should the commission prioritize the standards set out in §25.101(c)(6)(D)?* Brazos was the only party that urged the commission to prioritize the new standards. Brazos also advocated that the commission prioritize the proposed standards with the existing standards in the Public Utility Regulatory Act (PURA) §37.056(c)(4). All other comments that answered the question recommended that the commission *not* prioritize the proposed standards. Most of the comments agreed with STEC that the "relevant criteria that should be used will depend on the circumstances that exist in each case."

The commission concludes that the standards set out in §25.101(c)(6)(D) should not be prioritized, and that they should be evaluated on a case-by-case basis in the context of the standards found in PURA §37.056(c)(4).

Several parties provided comments urging additional amendments to §25.101 (Reliant, FPLE, and SPS). The scope of the changes in this adopted amendment was fairly narrow, and making broader amendments warrants the opportunity for interested parties to comment. These recommended amendments will be addressed in a subsequent rulemaking project.

Most of the parties agreed with Reliant's statement that recognized that "landowners and land use are important criteria that must be fully considered when proposing new transmission facilities." Utilities generally agreed that the amended certification criteria are already taken into consideration both by utilities and the commission Staff when routing transmission lines (El Paso, AEP, and TXU). LCRA indicated that the spirit of the proposed rule changes is reflected in LCRA Board Policy 601, and STEC stated that the "proposed amendment merely codifies in the Commission's Substantive Rules current Commission policy concerning the routing of transmission lines."

Reliant stated that the "factors singled out in the proposed rulemaking should not carry more weight than the many other factors that statutorily must be considered in siting a transmission project" and urged that the proposed rule amendment not be adopted, and FPLE agreed with this recommendation. STEC and the Farm Bureau supported the adoption of the rule amendment, and Farm Bureau stated that this amendment "is an excellent first step in ensuring that the process properly balances the need of landowners with the need for new transmission lines" (Farm Bureau). Several parties generally supported the rule amendment but recommended modifications or clarifications (AEP, Brazos, ETEC, LCRA, and TXU).

Some utilities were concerned that the amended certification criteria are subjective and will be interpreted as requirements or absolute directives that will take precedence over all other factors in PURA §37.056(c)(4), or will unintentionally introduce inflexibility into the route selection process (Brazos, ETEC, Reliant, SPS, and TXU). Many of the comments recommended specific modifications to the proposed language to lessen some of these concerns. These recommendations are addressed individually below.

Several parties commented that the amended certification criteria should include an evaluation of economic feasibility and costs-effectiveness in the determination of a transmission route (AEP, Brazos, PEC, TEC, and SPS).

The commission agrees that the cost of constructing transmission facilities is a factor that should be considered when selecting a route, and a factor recognizing economic feasibility has been included in the certification criteria in the adopted rule amendment.

Several parties suggested that utilities should not be constrained by the amended certification criteria if the utility and directly affected landowners agree to routes that are otherwise in compliance with the factors in PURA §37.056(c) (STEC, SPS, Farm Bureau, and Reliant).

The commission agrees, and language has been included in the certification criteria in the adopted rule amendment that recognizes that landowners and utilities may agree to routes that do not adopt the proposed certification criteria, but otherwise conform to the factors established in PURA §37.056(c).

The proposed rule amendment stated that the certification criteria would be applied "where practical." Some utilities expressed concern about the use of the term "practical" (Brazos and ETEC). Brazos suggested that the commission substitute the word "reasonable" and argued that the "reasonable man standard," and its application as a legal standard, has been widely used by the courts and in case law for years. TXU suggested the use of the term "reasonably practical" to support the concept of flexibility.

The commission finds definitions of the term "practical" to include "capable of being put to use or account" and "when something can be done or performed." Definitions of the term "reasonable" include "rational, appropriate, and not extreme or excessive." The commission concludes that the use of the term "reasonable" is more appropriate.

Some utilities suggested that paralleling geographical or cultural features such as existing roadways, waterways, edges of timber, or fence lines or other natural divisions of property could offer the same diminished impact on large tracts of land as paralleling property lines (Brazos, ETEC, and STEC).

The commission agrees and the adopted rule incorporates this concept.

All comments, including any not specifically referenced herein, were fully considered by the commission. In adopting this section, the commission makes other minor modifications for the purpose of clarifying its intent.

This amendment is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2001) (PURA), which provides the Public Utility Commission of Texas with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; and specifically, §37.051, which requires an electric utility to obtain certification for electric facilities, and §37.056, which governs the issuance of certificates of convenience and necessity for electric facilities.

Cross Reference to Statutes: Public Utility Regulatory Act §14.002 and PURA Chapter 37, Subchapter B.

*§25.101. Certification Criteria.*

(a) Definition. The term "generating unit," when used in this section, shall mean any electric generating facility. This section does not apply to any generating unit that is less than ten megawatts and is built for experimental purposes only, and not for purposes of commercial operation.

(b) Certificates of convenience and necessity for existing service areas and facilities. For purposes of granting these certificates for those facilities and areas in which an electric utility was providing service on September 1, 1975, or was actively engaged in the construction, installation, extension, improvement of, or addition to any facility actually used or to be used in providing electric utility service on September 1, 1975, unless found by the commission to be otherwise, the following provisions shall prevail for certification purposes:

(1) The electrical generation facilities and service area boundary of an electric utility having such facilities in place or being actively engaged in the construction, installation, extension, improvement of, or addition to such facilities or the electric utility's system as of September 1, 1975, shall be limited, unless otherwise provided, to the facilities and real property on which the facilities were actually located, used, or dedicated as of September 1, 1975.

(2) The transmission facilities and service area boundary of an electric utility having such facilities in place or being actively engaged in the construction, installation, extension, improvement of, or addition to such facilities or the electric utility's system as of September 1, 1975, shall be, unless otherwise provided, the facilities and a corridor extending 100 feet on either side of said transmission facilities in place, used or dedicated as of September 1, 1975.

(3) The facilities and service area boundary for the following types of electric utilities providing distribution or collection service to any area, or actively engaged in the construction, installation, extension, improvement of, or addition to such facilities or the electric utility's system as of September 1, 1975, shall be limited, unless otherwise found by the commission, to the facilities and the area which lie within 200 feet of any point along a distribution line, which is specifically deemed to include service drop lines, for electrical utilities.

(c) Certificates of convenience and necessity for new service areas and facilities. Except for certificates granted under subsection (b) of this section, the commission may grant an application and issue a certificate only if it finds that the certificate is necessary for the service, accommodation, convenience, or safety of the public. For transmission line certificate applications the commission shall give great weight to the recommendation of the Electric Reliability Council of Texas (ERCOT) Independent System Operator (ISO) in determining the need for a proposed transmission line.

(1) The commission may issue a certificate as applied for, or refuse to issue it, or issue it for the construction of a portion of the contemplated system or facility or extension thereof, or for the partial exercise only of the right or privilege. The commission may amend or revoke any certificate issued under this section if it finds that the public convenience and necessity requires such amendment or revocation. A certificate, or certificate amendment, is required for the following:

(A) a change in service area;

(B) a new electric generating unit;

(C) a new electric transmission line;

(D) a qualifying facility which is making or plans to make retail sales of electricity to an end user, unless the end user is also the sole purchaser of the thermal output of the qualifying facility, or unless the qualifying facility generates less than 10 megawatts of electric power by renewable resources, biomass, or waste. As a requisite to certification, the commission shall find that the ratepayers of the electric utility in whose service area the purchasing end user is located will not be substantially adversely impacted as a result of such retail sales.

(2) A certificate is not required for the following:

(A) a contiguous extension of those facilities described in the Public Utility Regulatory Act §37.052;

(B) a new electric high voltage switching station, or substation;

(C) routine activities associated with transmission facilities that are conducted by electric utilities, including wholesale generation and transmission utilities, and as specifically noted following:

*(i)* the alteration of an existing transmission line to provide service to a customer-owned substation or metering point, or to an electric utility-owned substation, where that electric utility-owned substation is located within two spans of the existing transmission line, provided that all utilities whose certificated service area is crossed are provided notice at least 30 days prior to the start of construction of the new facility, or the new facility is being constructed to serve a utility certificated in the area where the new facility is to be constructed and all landowners whose property is crossed by the transmission facilities constructed to connect the substation to the existing transmission line have given prior consent;

*(ii)* the rebuilding, upgrading, bundling of conductors or reconductoring of an existing transmission facility; or the installation of an additional circuit(s) on facilities that were originally certificated for multiple-circuit capacity, provided no additional right of way is required. Activities described in this clause which occur in the certificated area of another electric utility require that utility to be provided notice at least 30 days prior to the start of construction of the new facility. However, if the rebuilding, upgrading, bundling of conductors or reconductoring is being done to serve a utility certificated in the area where those activities are to take place, then no such notice is required. However, within multiply-certificated areas, only notice, not consent, is required. For purposes of this section, "upgrading" to a higher voltage shall be limited to 230 kV or less and "rebuilding" work shall be limited to the replacement and/or respacing of structures along an existing route of the transmission line;

*(iii)* the relocation of all or part of an existing transmission facility due to a request for relocation to be done at the expense of the requesting party and to be relocated solely on rights-of-way provided by the requesting party. Activities described in this clause which occur in the certificated area of another electric utility require that utility to be provided notice at least 30 days prior to the start of the relocation.

*(iv)* the relocation or alteration of all or part of an existing transmission facility to avoid or eliminate existing encroachments, provided that all utilities whose certificated service area is crossed are provided notice at least 30 days prior to the start of the relocation or alteration and all landowners whose property is crossed by such relocation or alteration have given prior consent;

*(v)* the relocation, alteration, or reconstruction of a transmission facility due to the requirements of any federal, state, county, or municipal governmental body or agency for purposes of highway transportation, airport construction, public safety, or air and water quality, provided that the relocation, alteration or reconstruction is responsive to the governmental request and is within 200 feet of the existing facilities and that any new landowner crossed by the relocation, alteration or reconstruction has given prior consent;

*(vi)* nothing contained in clauses (i)-(v) of this subparagraph should be construed as a limitation of the commission's authority as set forth in the Public Utility Regulatory Act. Any activity described in clauses (i)-(v) of this subparagraph must be reported to the commission, on commission prescribed forms, not less than 30 days prior to the commencement of construction, and the commission may require additional facts or call a public hearing thereon to determine whether a certificate of convenience and necessity is required. For projects that require new or additional rights-of-way direct mail notice is required to landowners of adjacent property within 200 feet of the proposed project, the parks and recreation areas within 1,000 feet, and airports within 10,000 feet, of the proposed project.

*(vii)* the repair or reconstruction of a transmission facility due to emergency situations shall proceed without delay or prior approval of the commission. Once emergency repairs have been performed and power has been restored, the affected utility shall file a report, within 30 days, describing the work performed and the associated costs. Final reports detailing associated costs must be filed within 90 days after completion of the repair or reconstruction.

(D) the construction or upgrading of distribution facilities within the electric utility's service area.

(3) The term construction and/or extension, as used in this section, shall not include the purchase or condemnation of real property for use as facility sites or right-of-way. However, prior acquisition of such sites or right-of-way shall not be deemed to entitle an electric utility to the grant of a certificate of convenience and necessity without showing that the proposed extension is necessary for the service, accommodation, convenience, or safety of the public.

(4) The commission shall render a decision approving or denying an application for a certificate required under paragraph (1) of this subsection within one year of the date of filing of a complete application for such a certificate, unless good cause is shown for exceeding that period.

(5) Expedited Approval:

(A) Uncontested applications: Except for an application for a new transmission line, an application for a certificate under paragraph (1) of this subsection shall be approved administratively within 80 days from the date of filing a complete application if:

*(i)* no motion to intervene has been filed or the application is uncontested; and

*(ii)* the commission staff has determined that the application meets all applicable statutory criteria and filing requirements, including, but not limited to, the provision of proper notice of the application.

(B) Minor boundary or service area exceptions: In the case of minor boundary changes or service area exceptions, such applications shall be approved administratively within 45 days of the filing of the application and may be approved sooner if good cause is shown, provided that all utilities whose certificated service area is affected agree to the change and all customers within the affected area have given prior consent.

(C) Uncontested transmission lines: An application for a certificate for a transmission line shall be approved administratively within 80 days from the date of filing a complete application if:

*(i)* no motion to intervene has been filed or the application is uncontested;

*(ii)* for those projects within ERCOT, the ERCOT ISO has recommended approval of the project if it is the type of transmission project which the ISO considers and approves; and

*(iii)* the commission staff has determined that the application meets all applicable statutory criteria and filing requirements, including, but not limited to, the provision of proper notice of the application.

(D) Projects deemed critical to the reliability of the ERCOT system: Applications for transmission lines which have been designated by the ERCOT ISO as critical to the reliability of the ERCOT system shall be considered by the commission on an expedited basis. The commission shall render a decision approving or denying an application for a certificate under this subsection within 180 days of the date of filing a complete application for such a certificate unless good cause is shown for extending that period. These procedures may be applied to transmission lines located in other reliability councils or administered by other independent system operators provided such councils have a process for designation of critical transmission lines.

(6) Standards of construction. In determining standard practice, the commission will be guided by the provision of the American National Standards Institute, Incorporated, the National Electric Safety Code, and such other codes and standards that are generally accepted by the industry, except as modified by this commission or by municipal regulations within their jurisdiction. Each electric utility shall construct, install, operate, and maintain its plant, structures, equipment, and lines in accordance with these standards, and in such manner to best accommodate the public, and to prevent interference with service furnished by other public utilities insofar as practical.

(A) The standards of construction shall apply to, but are not limited to, the construction of any new electric transmission facilities, rebuilding, upgrading, or relocation of existing electric transmission facilities.

(B) For electric transmission line construction requiring the acquisition of new rights-of-way, electric utilities must include in the easement agreement, at a minimum, a provision prohibiting the new construction of habitable structures within the right-of-way. However, utilities may negotiate appropriate exceptions in instances where the electric utility is subject to a restrictive agreement being granted by a governmental agency or within the constraints of an industrial site. Any exception to this paragraph must meet all the applicable requirements of the National Electric Safety Code.

(C) For the purposes of subparagraph (B) of this paragraph the term "habitable structures" means those structures normally inhabited by humans on a daily, or regular basis including, but not limited to, single-family dwellings and related structures, apartment buildings, business structures, major additions to the aforementioned types of pre-existing structures, and mobile home parks. However, the phrase "new construction of habitable structures" under subparagraph (B) of this paragraph shall not include necessary repairs to existing structures, farm or livestock facilities, storage barns, hunting structures, small personal storage sheds, or similar structures.

(D) A new transmission line shall meet the criteria in the Public Utility Regulatory Act (PURA) §37.056 and considering those criteria, engineering constraints, and costs, shall be routed to the extent reasonable to moderate the impact on the affected community and directly affected landowners unless grid reliability and security dictate otherwise. The following factors shall be considered unless a route is agreed to by the utility and directly affected landowners and otherwise conform to PURA §37.056:

*(i)* whether the preferred and alternate routes utilize existing compatible rights-of-way, including the use of vacant positions on existing multiple-circuit transmission lines;

*(ii)* whether the preferred and alternate routes parallel existing compatible rights-of-way; and

*(iii)* whether the preferred and alternate routes parallel property lines or other natural or cultural features.

(d) Transferability of certificates. Any certificate granted under this section is not transferable without approval of the commission and shall continue in force until further order of the commission.

(e) Exclusiveness of certificate. Any certificate granted under this section shall not be construed to vest exclusive service or property rights in and to the area certificated. The commission may grant, upon finding that the public convenience and necessity requires additional certification to another electric utility or utilities, additional certification to any other electric utility or utilities to all or any part of the area heretofore certificated under this section.

(f) Certification forms. The commission shall adopt a form or forms that will facilitate the granting of certificates so that the granting of certificates, both contested and uncontested, will be expedited. Forms may be obtained from central 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 September 26, 2001.

TRD-200105831
Rhonda G. Dempsey
Rules Coordinator
Public Utility Commission of Texas
Effective date: October 16, 2001
Proposal publication date: June 15, 2001
For further information, please call: (512) 936-7308

♦ ♦ ♦

## SUBCHAPTER R. CUSTOMER PROTECTION RULES FOR RETAIL ELECTRIC SERVICE

### 16 TAC §25.476

The Public Utility Commission of Texas (commission) adopts new §25.476, relating to Labeling of Electricity with Respect to Fuel Mix and Environmental Impact, with changes to the proposed text as published in the May 18, 2001 *Texas Register* (26 TexReg 3587). The rule is necessary to further the Legislature's goals as set forth in the Public Utility Regulatory Act (PURA) §39.101 to ensure that residential and small commercial electricity customers in areas of retail competition: (a) receive sufficient information to make an informed choice of service provider; (b) are protected from unfair, misleading, or deceptive practices; and (c) are provided with information in a standard format that will permit comparison of the environmental impacts associated with certain production facilities. The provisions of this section govern how retail electric providers (REPs) and affiliated REPs calculate the fuel and emissions components of the Electricity Facts label (EFL) as required under §25.475 of this title (relating to Information Disclosures to Residential and Small Commercial Customers). This new section is adopted under Project Number 22816.

An earlier version of this rule was proposed in the February 2, 2001 issue of the *Texas Register* (26 TexReg 1051). The commission subsequently found that the use of the term "power generation company" was too narrow for the purposes of the proposed rule, however, and decided to republish the rule replacing that term with the more inclusive "owner of generation assets." Republication was necessary because the new term expanded the scope of affected parties beyond what was originally published. In its decision to republish, the commission also decided to defer a number of other changes until final adoption. These changes were included in a memorandum from Chairman Pat Wood, III to Commissioner Brett A. Perlman, filed April 18, 2001, and discussed at the commission's April 24, 2001 open meeting.

Broadening the scope of this rule affected issues in Docket Number 23802, *Proceeding to Consider Section 14 of the ERCOT Protocols (Severed from Docket No. 23220)*, with the most significant common issue being the treatment of renewable energy credit (REC) offsets. The commission's final order in that docket resolved key issues for most parties, however, eliminating the need for special provisions in this rulemaking to accommodate REC offset holders.

A public hearing on the proposed section was held at commission offices on June 21, 2001, at 9:30 a.m. Representatives from Central Power and Light Company, Southwestern Electric Power Company, and West Texas Utilities Company (collectively, American Electric Power Company, Inc. (AEP)), the City of Austin d/b/a Austin Energy (Austin Energy), Brazos Electric Power Cooperative, Inc. (Brazos), Brownsville Public Utilities Board, East Texas Cooperatives (ETEC), the Electric Reliability Council of Texas (ERCOT), Entergy, Green Mountain Energy Company (Green Mountain), Lower Colorado River Authority (LCRA), Reliant Energy, Inc. (Reliant), Southwestern Public Service Company (SPS), Texas Ratepayers' Organization to Save Energy and TXU Electric Company (TXU) attended the hearing and provided comments. To the extent that these comments differ from the submitted written comments, such comments are summarized herein. No further comments were accepted after the public hearing.

The commission received written comments on the proposed new section from AEP; Austin Energy; Brazos; City Public Service Board of San Antonio (San Antonio); El Paso Electric Company (EPE); ETEC; Environmental Defense; ERCOT; Green Mountain; Enron Energy Services Inc, The New Power Company, and Strategic Energy Ltd. (collectively, Independent Marketers); LCRA; Linda Hajek; Public Citizen; Reliant; SPS; South Texas Electric Cooperative, Inc. (STEC); State of Texas; Texas Electric Cooperatives, Inc. (TEC); Texas Ratepayers' Organization to Save Energy, Consumers Union Southwest Regional Office, Texas Legal Services Center, and AARP (Consumer Commenters); Texas Renewable Power Coalition (TRPC); TXU; and the U.S. Department of Energy (DOE).

All section numbers cited in the following summary correspond to the rule as published in the May 18, 2001 issue of the *Texas Register*. Unless specifically indicated otherwise, all references are to §25.476.

COMMENTS ON QUESTIONS PUBLISHED FEBRUARY 2, 2001

*Question No. 1: Should the commission require a competitive retailer to disclose the megawatt-hours (MWh) of electricity it sells under each of its various products, as proposed under subsection (g)(7)(A), if those products are marketed with different fuel mix and environmental disclosures? If not, how should the commission verify that a competitive retailer has not sold more electricity under a "green" or "renewable" label than it obtained from its suppliers?*

AEP, Consumer Commenters, Environmental Defense, Green Mountain, Independent Marketers, Public Citizen, Reliant, SPS, State of Texas and TXU said that the report required under subsection (g) was an appropriate method for ensuring that competitive retailers have not sold more of a specific energy product than the retailer has actually acquired. Independent Marketers agreed with TXU that the disclosure of such information *to the commission* will enable the commission to verify the information, but cautioned that this will be highly sensitive, competitive information and must be protected from further disclosure (emphasis in original comment). Citing PURA §39.001(b)(4), which provides that it is in the public interest to protect the competitive process in a manner that ensures the confidentiality of competitively sensitive information, Independent Marketers argued that the megawatt hour sales of each product will be competitively sensitive information which must therefore be protected from disclosure to persons outside the commission. Green Mountain, Reliant and TXU made similar arguments. Similarly, Environmental Defense suggested that if retailers have competitive concerns about this information, they should submit it under seal so that the accuracy of their disclosures could be verified by the commission. On the other hand, State of Texas said it did not see the merit in affording confidential treatment to the information, and that general principles of open government and public access to information should prevail. Public Citizen said the information should not only be provided to the commission but should also be posted on the Internet.

The commission agrees with Independent Marketers and other parties that disclosure to the commission is a reasonable tool for evaluating the marketing claims regarding fuel mix or emissions. The commission recognizes that retailers may regard some of this information as competitively sensitive, however. PUC Procedural Rule §22.71 provides a method by which REPs may declare documents confidential and submit those under seal. PURA §39.001(b)(4) also mandates that it is in the public interest to protect the competitive process in a manner that ensures the confidentiality of competitively sensitive information during the transition to a competitive market and after the commencement of customer choice. The commission requires REPs to fully disclose all information required under §25.476, and a REP may file its report according to Procedural Rule §22.71. The commission will apply the standard of PURA §39.001(b)(4) in determining whether a presumption of confidentiality is appropriate, and amends §25.476(b) accordingly. The commission also acknowledges that it is bound to follow the requirements of the Texas Government Code Chapter §552.001, *et. seq.*, the Texas Public Information Act (PIA). As with all requests for information, the commission will comply with the PIA's requirements in determining whether to release information.

Independent Marketers also stated that there should be no required disclosure of megawatt hour sales regarding a retailer's standard product or regarding products for which the retailer does not associate with a specific fuel mix or specific emissions marketing claim.

The commission disagrees with Independent Marketers and finds that megawatt hour sales regarding a retailer's standard product should be required regardless of whether or not the retailer is making a specific fuel mix or specific emissions marketing claim. Data for all products are mathematically essential for calculating the overall residual or default scorecard described in subsection (e), which in turn is essential for more accurate disclosures to customers. The purpose of this rule will still be served, however, if the retailer wishes to aggregate data for all products carrying the same fuel and emissions profile. The disclosure is still required, however, regardless of how the retailer markets the products.

TEC asserted that proposed §25.476(g)(1) conflicts with the statutory provisions of PURA §41.004(5), while San Antonio said the section conflicts with PURA §40.004(7). TEC recommended revision of the proposed rule text to clarify that §25.476(g)(1) applies to entities other than an electric cooperative (co-op) or a municipally owned utility (MOU). San Antonio urged the commission to make the reporting requirements proposed under subsection (g)(1) voluntary rather than mandatory for MOUs because the requirement, as proposed, is outside the scope of the reports that may be required by the commission under PURA §40.004(7).

Environmental Defense responded to TEC's and San Antonio's assertion and commented that if MOUs and co-ops are not required to report the information, authentication of these entities' facts labels would be impossible. Environmental Defense commented that these entities generally purport to be responsive to their customers; therefore, Environmental Defense found it curious that these entities are now reticent to disclose information that would authenticate the electric products that they offer. Environmental Defense concluded that unless every entity that provides competitive retail electric services is subject to the same requirements regarding EFLs, then customers' ability to make informed decisions about the electricity products available in the market is seriously weakened.

The commission shares the concerns of Environmental Defense and agrees that if municipally owned utilities and electric cooperatives are not required to report the information, authentication of what they tell their customers will be nearly impossible. The commission disagrees with San Antonio and TEC that §25.476(g)(1) is in conflict with PURA §40.004(7) and §41.004(5) with respect to municipally owned utilities and electric cooperatives operating as competitive retailers outside their certificated service territories. The commission reminds all commenters of its decision in the order adopting Chapter 25 Subchapter R, Customer Protection Rules for Retail Electric Service:

"The commission agrees that these customer protection rules apply to customers served by an electric cooperative or municipally owned utility operating outside of its certificated service area. ...The commission also determines that PURA §17.005 and §17.006 give an electric cooperative or municipally owned utility the authority to adopt and enforce its own customer protection rules for customers *inside its certificated service area*, which must meet the customer protection objectives of PURA. The commission's rules should serve as a model for the minimum customer protections that all customers can expect in a competitive market." (*Customer Protection Rules for Retail Electric Service*, Project No. 22255, Order (December 20, 2000) at 307, emphasis added.)

The commission further notes that as §25.476 will be part of Subchapter R, the term "competitive retailer" as used in this rule is defined in §25.471(d)(3), which includes MOUs and co-ops that have opted into competition only to the extent that they operate outside their certificated service areas. Therefore, the reporting required by §25.476(g)(1) does not apply to service by an MOU or co-op within that entity's certificated service area. Within its certificated service area, however, an MOU or co-op may voluntarily use the provisions of this rule as a mechanism for its own electricity labeling, if offered, and may voluntarily report supplier information as San Antonio suggests.

*Question No. 2: The proposed rule allows electricity generated outside of Texas to be included in a competitive retailer's fuel and environmental disclosure if there is a supply contract between the competitive retailer and the owner of the out-of-state generation facility (subsection (g)(2)). However, subsection (f) excludes non-Texas facilities from the proposed certificates program. Does this allow a competitive retailer sufficient means to authenticate its use of out-of-state generation to meet customer demand in Texas?*

AEP, Environmental Defense, Independent Marketers, Reliant, SPS, State of Texas and TXU said the rule as proposed provides sufficient means for REPs to authenticate out-of-state generation. Green Mountain also supported the provision, but suggested language that would allow authentication through power marketers who have direct contracts with power generation companies (PGCs) and can provide the contract documentation needed to verify fuel and emission sources for generating facilities used to serve a REP's load. AEP sought clarification on the timing of reporting out-of-state contracts used to support fuel mix and environmental impact claims.

The commission declines to expand §25.476(g)(2) as suggested by Green Mountain. Tracking purchases through power marketers raises the kind of technical and accounting difficulties the commission has sought to avoid throughout this rulemaking. However, the commission has no objection to reporting under this section, where a power marketer acts as a broker between a specific generator and a specific retailer, as long as the result is a supply contract that involves no other generator or retailer. Otherwise, supplies purchased by a retailer from a power marketer are considered system power and shall be represented by the default scorecard. With regard to timing, the commission modifies §25.476(g) to clarify that information pertaining to out-of-state supply contracts must be included in the retailer's six-month supply reports.

AEP noted that PURA §39.9044(d)(2) specifies that electricity generated from natural gas may be marketed as "green" only if the natural gas is produced in Texas, and that the proposed rule does not address this distinction. State of Texas also suggested adding language specifying that when out-of-state supply contracts are used for green energy, natural gas cannot be included as a component of that supply. Similarly, Public Citizen said that a REP should be able to use non-Texas renewable or green power in its disclosures to customers only if it can provide data that are functionally equivalent to what is required under Texas rules. Consumer Commenters said that non-Texas resources should be subject to the same verification procedures as in-state resources.

The commission finds that it is not necessary to distinguish between Texas and non-Texas natural gas with respect to the fuel mix calculations described in this rule. Natural gas produced in New Mexico, Oklahoma or Louisiana may not qualify as "green" under PURA §39.9044(d)(2), but it is still natural gas and therefore should be shown as such in the fuel mix on the Electricity Facts label. PURA §39.9044(d)(2) pertains only if the retailer plans to market the power as "green." The commission therefore adds new paragraphs to §25.476(d) and (g)(1) specifying that if a retailer intends to tell customers that the natural gas in its fuel mix is "green," it must provide the commission with proof that the natural gas was produced in Texas.

*Question No. 3: Subsection (d) of the proposed rule sets forth a general principle for marketing electricity products as "green" or "renewable." Should the proposed rule set such standards, and if so, what should they be? If there is to be a fixed benchmark for marketing an electricity product as 'green,' how much of the fuel mix should be renewable or natural gas? How much should come from renewable fuels before it can be sold to customers as "renewable"?*

SPS, Public Citizen, State of Texas, Consumer Commenters, and Environmental Defense all supported fixed benchmarks for marketing "green" and "renewable" products. SPS, State of Texas, and Environmental Defense agreed that energy products labeled "renewable" should be 100% renewable generation sources. SPS, Public Citizen, and State of Texas said that power marketed as "green" should come from generation sources that use only natural gas. Consumer Commenters, however, said that any product marketed as "green" should be 100% renewable. Replying to SPS, Environmental Defense argued that it should be permissible to count generation from either natural gas or renewable sources as "green," otherwise customers would likely be confused.

TXU, AEP, Reliant Energy, Independent Marketers, TRPC, and Green Mountain all opposed fixed benchmarks. TXU and AEP argued that if customers do not know the criteria used, the benchmarks may be confusing. In addition, the two companies stated that a benchmark would not allow consumers the opportunity to choose products that only in part contain "green" or "renewable" energy if their products fail to meet the criteria. Green Mountain, Independent Marketers, Reliant, San Antonio, and TXU argued further that the fixed benchmark for marketing "green" or "renewable" energy retards product differentiation. Independent Marketers argued that setting benchmarks "would be analogous to removing the detailed information required by law on current food labels concerning grams of fat, protein, carbohydrate, etc." In its reply comments, Green Mountain said that a fixed benchmark is not a protection against misleading claims by retailers and could possibly retard the growth of the market for renewable generation.

State of Texas and Environmental Defense agreed that it would be appropriate for companies whose products do not meet a benchmark to label their products with the percentage of "green" and "renewable" as long as the claim was accurate. To this end, State of Texas suggested amending subsection (d)(1) so that it corresponds to subsection (d)(2): "A product may be marketed as 'green' without reference to a fuel mix percentage only if the product's authenticated fuel mix is 100% 'green.'" TRPC, however, suggested modifying subsection (d)(1) so that marketing statements about a "green" product include the individual percentage of natural gas and the individual percentage of renewable energy, rather than the sum of the two. Similarly, Consumer Commenters said that when renewable power sources are combined with other resources, all advertising and all marketing materials should specifically state the renewable percentage. Public Citizen argued that so little renewable energy exists that it should be marketed as a percentage. Environmental Defense agreed with the revision proposed by State of Texas, but added that "green" should also include a combination of natural gas and renewable energy and that a product composed of 100% renewables should also qualify as "green."

TXU, however, said subsection (d)(1) should be modified so that the retailer does not have to disclose its product's mix percentage. Rather, it argued, there should be an option in the rule for retailers to state the "availability of such information." Environmental Defense disagreed, arguing that the furthest the TXU proposal could be taken would be to clarify that a competitive retailer or affiliated REP "may market an electricity product as 'green' or 'renewable' if the criteria in the subsections are met."

The commission agrees with Consumer Commenters, Environmental Defense, Public Citizen, SPS and State of Texas that a fixed benchmark should be established for the marketing of "green" and "renewable" sources. The aim of the Electricity Facts label is to give consumers a clear, informative and accurate guide to the electricity available to them. Therefore, the commission finds that power marketed as "renewable" should comprise 100% renewable sources. Likewise, power marketed as "green" should comprise electricity generated 100% from renewable energy, Texas natural gas, or any combination of the two. While the commission is sympathetic to TRPC's suggestion that the renewable energy and natural gas percentages be disclosed separately on marketing materials, the commission finds that the same end will be accomplished by a disclaimer: "A green product may include Texas natural gas and renewable energy. See the Electricity Facts label for this product's exact mix of renewable energy and Texas natural gas." This allows a retailer more flexibility in advertising while at the same time directing the customer's attention to the Electricity Facts label.

*Question No. 4: PURA §39.262 requires affiliated power generation companies (PGCs) to auction entitlements to 15% of their generating capacity. Section 25.381, relating to Capacity Auctions, establishes four kinds of capacity auction products, three of which are fueled by natural gas and the other by coal, lignite, and nuclear energy. How should the proposed labeling rule treat the fuel mix and associated emissions of generation that a retail electric provider (REP) acquires under capacity auctions?*

TXU noted that under §25.381, relating to Capacity Auctions, entitlements are not plant specific but rather are for system capacity. PGCs will know which of its plants will be available to generate power for each auction category, however. A category scorecard can be calculated from the characteristics of all units identified for possible dispatch in that auction. TXU also noted a much easier path would exist under the proposed rule if a REP wished to differentiate a product: it could acquire RECs or certificates of generation. Reliant commented that if capacity is acquired through one of the three natural gas generation auctions, it should be considered "green." Consumer Commenters and Public Citizen said that each capacity auction product will have emission characteristics that should be part of the purchasing REP's product mix, and that these characteristics should be adjusted annually. Environmental Defense and Independent Marketers said that capacity auction purchases should be treated in the same manner as electricity obtained through a supply contract with the PGC. AEP, Independent Marketers, SPS and State of Texas said capacity acquired at auction should be treated in the same manner as all other sources of energy.

Because capacity auction products are not plant-specific, power acquired under a capacity auction cannot be treated in the same manner as all other sources of energy. The commission finds that TXU's proposal for capacity auction scorecards is reasonable, feasible and consistent with §25.381. Subsection (e) is amended to include TXU's proposal. The commission further finds that this approach is consistent with the points made by Consumer Commenters and Public Citizen.

COMMENTS ON QUESTIONS PUBLISHED MAY 18, 2001

The first two questions published by the commission on May 18, 2001 involved the certificates of generation program described in subsection (f). Indeed, a large portion of the comments received by the commission concerned the certificates program either directly or in connection with other aspects of the rule. After reviewing the various comments summarized below, the commission finds that the proposed certificates of generation program should not be a mechanism for Electricity Facts label disclosures during the first year of full competition. Whether and how such a program could enhance product disclosures can only be determined with confidence after the competitive market has matured and participants' interests have been informed by actual experience. The reasons for this decision are set forth in the discussion below regarding original subsection (f) and the first two questions asked by the commission on May 18, 2001.

*Question No. 1: Should owners of renewable energy generation assets have the option to split a plant's output between a certificate of generation and a renewable energy credit (REC) offset? If so, what procedure would ensure that the output is not double-counted?*

AEP, EPE and LCRA said eligible facilities should be allowed to both qualify for REC offsets and issue certificates of generation. LCRA added that once a facility's output (either in part or in total) is converted from an offset to a certificate, there should be no reverting back to an offset. On the other hand, Reliant, TXU and ETEC said eligible facilities should be designated as REC offset generators or allowed to earn certificates of generation, but not both. Brazos said that the additional complexity of dividing the output would seem to outweigh the benefits of the certificate program itself.

The commission finds that the issue of splitting the output of eligible facilities between REC offsets and certificates of generation should be resolved when it has been determined that the certificates program is necessary. At that time, the commission will weigh the complexity cited by Brazos, ETEC, Reliant and TXU against the benefits anticipated by AEP, EPE and LCRA, in the context of the issues the program has to address.

*Question No. 2: How should the optional certificates program accommodate generation from federally owned hydroelectric facilities whose output must be sold to municipally owned utilities and electric co-operatives?*

DOE noted that the commission has no authority over federal agencies, including those that operate and sell power from federally owned hydroelectric facilities. Nevertheless, DOE said that if the commission were to include federally owned hydroelectric plants in the optional certificates of generation program for Texas, DOE would itself issue one-year certificates to its existing hydropower customers, and that such certificates could not be resold or otherwise transferred to another party without the approval of DOE.

Brazos, ETEC and STEC commented extensively on this question and more broadly on co-ops' disclosure obligations under the commission's proposed rule. All three said that given the commission's decision in Docket Number 23802, *Proceeding to Consider Section 14 of the ERCOT Protocols (Severed from Docket No. 23220)*, there was no need from their perspective to include federal hydroelectric resources that are currently accounted for by REC offsets in the proposed certificates program. STEC and Brazos said making federally owned hydro eligible for certificates as an alternative to REC offsets could jeopardize the co-ops' preference power and could create conflicts between the co-ops and the federal power marketing entities. STEC also said that the option to sell certificates could create conflict within a co-op's board of directors, consequently discouraging the board from opting into competition. In addition, ETEC said it would actually have less flexibility to take care of its member cooperatives' renewable resource needs if its offsets were converted to certificates because it does not actually own or control output from the hydro facilities and therefore would not own the certificates.

Relying upon the legal principles of mootness and jurisdiction, ETEC questioned the commission's purpose and the public policy reason for allowing REC offsets to be converted into generation certificates. It cited PURA §17.006 and argued that the commission has only limited jurisdiction over competitive activities of distribution cooperatives which choose to opt into retail competition, and then only to the extent that the distribution co-op provides competitive retail service outside its certificated service area or otherwise served through other's distribution facilities. Even if a cooperative opts into retail competition, ETEC argued that the commission has no jurisdiction over the labeling or marketing activities inside that co-op's certificated service area. As an example, ETEC said that if a retailer (or opt-in distribution cooperative) chooses to resell the generation certificate to another party while retaining the electricity, the retailer is required under the rule to use the generator's scorecard to describe the attributes of retained electricity. ETEC questioned whether that provision prevents an opt-in distribution cooperative that sells the generation certificate associated with its REC offset from telling its retail customers, or its retail customers receiving a competitive rate, that the electricity they are buying is a product of renewable generation. ETEC challenged this perception, because hydro is renewable.

Brazos expressed that it does not share staff's opinion that the proposed rule is a viable vehicle for co-ops with REC offsets, asserted that commission Docket Number 23802 adequately addressed Brazos' REC offset concerns, and recommended that there is no further need to continue making this rule applicable to co-ops. Brazos opposed adoption of the rule, as proposed, because the commission lacks authority with regard to co-ops, the benefits of the compromise reached in Docket Number 23802 would be destroyed, and because preference power issues as applied to federal resources may affect co-ops adversely.

Aside from comments by the co-ops, TXU said the certificates program should treat federal hydro no differently than it treats other facilities. Green Mountain was concerned that the commission's lack of jurisdiction over the actions of the federal government made federal participation in the certificates program problematic. In addition, Green Mountain said competitive problems could arise by allowing government-subsidized facilities to participate in a program that was designed to be pro-competitive.

The commission appreciates DOE's interest and cooperation with respect to the proposed certificates of generation. The commission also acknowledges the concerns raised by the electric cooperatives with regard to the treatment of federally owned hydro and especially their desire that it not be possible to convert REC offsets to certificates without the consent of the offset holder. The status of REC offsets is controlled by §25.173 of this title (relating to Goal for Renewable Energy) and by the ERCOT Protocols, Section 14. In view of its decision not to adopt a certificates program now, the commission finds that questions relating to the conversion of REC offsets need not be addressed in this rulemaking.

*Question No. 3: To simplify and streamline the reporting and calculation process, the commission has developed forms, spreadsheets, and templates, residing on the agency web-page, for data reporting from power generation companies (PGCs) and calculation of the generator scorecard. Prototype scorecards with supporting data can be found at http://www.puc.state.tx.us/rules/rulemake/22816/22816.cfm. The commission has also developed forms, spreadsheets and templates for retail electric provider (REP) calculation of fuel mix and emissions impacts, using the generator scorecards. These will be used for web-based reporting and automated data compilation, to minimize compliance effort and cost for the parties and the commission. Parties are welcome to comment on these forms and spreadsheets, which will be adopted after comment as part of final rule adoption.*

AEP said that the PGC scorecard unnecessarily complicates the implementation of the labeling rule with little or no real benefit. TXU recommended that the concept of the forms be incorporated into the adopted rule, but TXU believed the forms are complicated and should continue to be refined.

TXU commented that a retailer that does not wish to distinguish its power from default power should be able to simply report its total MWh sales as "Balance not accounted for" in the "Product" section, and should not be required to complete the "Contracts," "RECs," and "Certificates" sections of the spreadsheet. TXU further expressed concern over inconsistencies in the forms and spreadsheet with subsections (c)(1) and (g)(1)(A).

The commission disagrees with TXU. The Electricity Facts label is a tool for customers to use in making informed decisions regarding the purchase of electric power. It is not an optional marketing tool for REPs. The reporting requirements are for *all* REPs selling to residential and small commercial customers, regardless of whether they end up above or below average. The default scorecard is to be used only when the generation source is *not known* - i.e. for supplies purchased from power marketers, on the balancing energy market, or from some other source that does not have a commission-calculated scorecard. If the supplier has a scorecard, the scorecard must be used. This provision does not require the retailer to collect additional information beyond what is already known by the retailer. The reporting requirement therefore does not constitute a significant burden or a barrier to market entry.

TXU stated that the spreadsheets should allow for power associated with a single certificate of generation, REC, and REC offset to be apportioned among one or more product labels, so long as the total aggregate electricity that is associated with all of those occurrences of the same certificate number does not exceed the total electricity represented by that certificate. TXU further suggested that the data for power associated with certificates of generation, RECs, and REC offsets should be automatically inputed into the forms and spreadsheets through a link to the databases maintained by the REC program administrator. In addition, TXU stated that in the interest of efficiency and accuracy, certificate, REC, and REC offset identification numbers should be entered in sequentially numbered blocks.

Additional changes or additions to the spreadsheets were suggested by TXU: (1) configure spreadsheets so that each tab is labeled with a title and instructions to correspond with the contents of the tab and the electricity product to which the data corresponds; (2) tabs should "roll up" so that one Electricity Facts label is produced for each product; (3) shading should clearly delineate which fields are protected and which are not; (4) roll-up scorecard summary table should contain the information described in §25.476(e)(2); (5) "total" line or "weighted average" line, as appropriate, should be included on each spreadsheet; (6) each spreadsheet should ensure that the cell sizes are sufficient to accommodate the complete display of all required data; and (7) emissions and waste disclosures should be consistent and conform to the emissions listing order found in proposed §25.476(c)(6).

The commission finds that TXU's comments contain good suggestions for improvement to the proposed forms and spreadsheets. The commission does not find it necessary to incorporate the proposed modifications into the rule; however, the commission will use the suggestions to improve the reporting forms and spreadsheets.

San Antonio commented that the labeling of residual generator data should be modified to reflect that the Generator Scorecard is only intended to be used as an aid in the creation of the EFL and that the data may differ substantially from the actual unadjusted scorecard for the generation owner.

The commission finds San Antonio's suggestion reasonable. The commission amends subsection (e) to provide that unadjusted scorecards shall be posted on the commission's web site and that adjusted scorecards shall be included only on the reporting forms to be used by REPs, with a statement that the data may differ from the unadjusted scorecard and a reference to the commission's web site.

*Question No. 4: Should the PGC generation scorecards and the REP fuel mix label be updated only once per year, or would there be value to the market to develop updates at more frequent intervals once the competitive retail market has stabilized? For instance, would it be appropriate to use the same set of scorecards and fuel mixes for all of 2002, but change the reporting and update schedule to quarterly editions beginning in 2003? Given the availability of standardized, web-based, automated reporting and calculation of these informational tools, what would be the costs and benefits of more frequent updates, and what would be the appropriate timing and preparation schedule?*

TXU, SPS, AEP, and Reliant all stated that an annual update of the data with respect to generators' portfolios and subsequent scorecards is prudent. LCRA stated that generators whose portfolios change should update scorecards accordingly and new generators entering the market should have a scorecard.

El Paso Electric Company recommended that the commission's reporting deadline dates be more flexible and coincide with existing deadlines required by the U.S. Environmental Protection Agency under 40 CFR §75.64.

The commission appreciates EPE's desire to simplify overall reporting requirements. However, the quarterly reporting requirements under 40 CFR §75.64 require different information. Further, while the commission does not object to receiving reports more often than required, its proposed rule requires annual reporting. The commission makes no modification to its rule in response to this comment.

The commission agrees with TXU, SPS, AEP, and Reliant that an annual update to reflect portfolio changes that are reflected in generator scorecards is appropriate. This measure will not burden the commission or generators with administrative tasks and a scorecard that changes only once per year on a specified date will still result in an Electricity Facts label that will be easy for consumers to understand and use, as was intended.

TXU said quarterly updates of the Electricity Facts label would impose significant costs, and questioned whether the twice-yearly updates would be any more beneficial than annual updates. SPS said a REP's supply portfolio probably will not change significantly over the course of a year, therefore annual updates would be sufficient. TXU and Reliant said that updating labels more frequently than annually should be optional. San Antonio, also supporting annual updates, opined that customers who select a provider on the basis of fuel and environmental impact would probably be those with a long-term "buy and hold" strategy rather than a short-term "day trader" approach.

While the commission understands providers' preference for the Electricity Facts label to be updated only on an annual basis, it finds that semiannual updates will not pose an undue burden, especially with the elimination of the certificates program. The commission recognizes that midyear updates to the EFL will be based on the same generator data used for the previous label and therefore will not reflect changes in generator emission rates. But a REP's supply mix could easily change from one period to the next. Thus, a midyear update to the EFL would reflect changes in the REP's supply portfolio - a change that customers are entitled to know if it would affect their choice of electricity provider. San Antonio may be correct in its prediction of stable customer-buying strategies, but an important benefit of twice-yearly updates is that if a *retailer* changes its supply strategy, the customer will find out sooner rather than later and will be able to decide in a timely manner whether to change providers. The commission therefore amends the rule throughout to reflect updates to the Electricity Facts label every six months.

To accommodate new products, the commission further amends subsection (g) to allow retailers the option to authenticate new-product projections after six months. If the "at least as favorable" standard has been met after six months, then the retailer has the right to drop the word "projected" from the new product's label and make a more definitive statement about fuel mix and environmental impact. If the standard has not been met, then the retailer has another six months to manage its supply acquisitions and retirement of RECs so that, at the end of the year, the authenticated fuel mix and environmental impact is consistent with what customers were told.

*Question No. 5: As new generators enter the market and existing generators' portfolios change, what updating process should be developed to reflect these changes in the generator scorecards? Is it necessary to develop some verification process, as well, to assure that no erroneous or fraudulent reporting occurs?*

AEP believed that a PGC should not be required to report to the commission any fuel mix and emissions data not already required under §25.91 of this title (relating to Generating Capacity Reports) and noted that additional reporting and monitoring requirements increase the cost of compliance. AEP further stated that the commission should not develop and should not implement a labeling program that disproportionately places the compliance and reporting burden on PGCs rather than on REPs making renewable or green claims.

The commission acknowledges AEP's desire to reduce costs associated with reporting requirements. Section §25.91(g) provides a list of reporting items currently required concerning generation capacity and sales, and the commission finds that it has the authority to require further information relating to fuel mix and emissions data. While the commission appreciates AEP's concern regarding costs, the commission must consider the necessity for obtaining the information and the various options for requiring information from any person or entity under its jurisdiction. Moreover, many of the concerns raised by AEP and other parties regarding costs are addressed by not implementing the certificates of generation program. The commission declines to modify the rule in response to this particular comment.

AEP stated that it is the responsibility of the REPs to report energy supplies truthfully and accurately, making it unnecessary for the commission to create additional verification processes and requiring PGCs to report data more frequently than required by §25.91. SPS stated that a systematic sampling and analysis of REP Electricity Facts labels should be effective in policing of errors and fraud. LCRA recommended that the commission should develop new procedures to ensure that generators entering the market have a scorecard and that existing generators update their scorecard as the portfolio changes. LCRA noted that environmental attributes are reported to other State and Federal regulators, and that could serve as verification. TXU and Reliant agreed that the rule as proposed is appropriate because there are sufficient mechanisms already incorporated to verify and update generator information while maintaining flexibility to adapt to market changes. SPS encouraged the commission to audit disclosures made on the EFL to protect against errors and fraud.

The commission agrees that no further verification process is necessary. In addition, the commission will allow PGCs an opportunity to review scorecard data to check for errors prior to use of the data by retailers.

COMMENTS ON SPECIFIC SUBSECTIONS

*§25.476(a) - Purpose.*

TXU, SPS, Environmental Defense, and Reliant commented that the proposed rule provides an efficient and reasonable approach for the disclosure of fuel mix and emissions information for inclusion on the EFL. On the other hand, AEP and Austin Energy stated that they find the proposed rule to be needlessly complex and costly. Austin Energy went on to say that the rule fails to provide meaningful information to customers and does not fulfill its objective. Both AEP and Austin Energy recommend that the commission consider simplifying the entire process.

In response to a statement by TXU that the disclosure requirements are applicable only to retailers and PGCs who "voluntarily" choose to distinguish their electricity by the use of certificates of generation, renewable energy credits, or specific supply contracts, Environmental Defense proposed that subsection (a) be revised to state that competitive retailers and affiliated REPs must generate electricity labels for their electricity products and that "affiliated REPs" be included within the ambit of the proposed rule's requirements. TXU responded that proposed §25.476 along with §25.475 clearly require the use of EFLs by all competitive retailers and affiliated REPs and Environmental Defense had misinterpreted the use of the word "voluntarily" in TXU's initial comments.

Brazos, STEC, and ETEC questioned the commission's limited jurisdictional authority over electric cooperatives, and thus oppose adoption of the rule.

The commission acknowledges the concerns raised by AEP and Austin Energy with regard to the complexity of the proposed rule. The commission finds that the decision to withdraw the proposed certificates of generation program will address some of the concerns expressed and result in simplification of the process. The commission agrees with TXU that application of the rule is properly addressed elsewhere and no revision is necessary to subsection (a). The comments of Brazos, STEC and ETEC regarding the commission's jurisdiction over electric cooperatives are addressed in the discussion of Question Number 1 (February 2, 2001) and subsection (i).

*§25.476(b) - Application*

San Antonio stated that the application of the rule to competitive retailers is appropriate in limiting application of municipally-owned utilities acting in that capacity only to the extent they are serving outside their certificated areas. Brazos commented that the application of the rule to "owners of generation assets" as it applies to electric cooperatives is inconsistent with the commission's limited authority of co-ops as set forth in PURA §41.004(5).

The commission makes no changes to subsection (b) in response to these comments. With regard to the concerns of Brazos, the commission finds that it does have authority to collect generation data from electric cooperatives under PURA §39.155, which under PURA Chapter 41 is applicable to electric cooperatives, if the information is necessary for the development of a competitive retail market in the state.

*§25.476(c) - Definitions*

TXU Electric suggested that subsection (c)(1) and (c)(10) be revised to recognize that REC offsets should be used to authenticate fuel and emissions characteristics. Additionally, TXU stated that to the extent RECs were used to authenticate generation, the rule should refer to "retired" RECs in all instances. AEP stated that §25.476(c)(1) should be amended to allow affiliated REPs to use the authenticated generation provisions of the rule in the same manner as competitive retailers. AEP stated that subsection (c)(1) should be revised to strike "retired renewable energy credit (REC)," but that if the commission did not, the definition of authenticated generation should be expanded to include REC offsets. TPRC commented that subsection (c)(1) should be revised to state that it is "ultimately used on the Electricity Facts label of the competitive retailer."

The commission agrees that the definition of "authenticated generation" should be revised to include the output from certified REC offset generators. However, the commission points out that the offset itself is a fixed number based on historical generation. Thus, the numerical value of the offset cannot be used as authentication for current generation. Actual output must be used, but because the output is from a certified REC offset generator, the output is renewable as defined by PURA §39.904 and §25.173 of this title, and may be counted as such. Also, the commission adds the language suggested by TPRC that clarifies the authenticated generation will ultimately be used on the EFL.

AEP also suggested that the term "scorecard" as used in subsection (c)(3) and (c)(8) be revised to another term such as "fuel mix and environmental impact." It argued that this term inappropriately applies a judgment or grading of the PCG's fuel mix and emissions; it should be given a name or acronym that does not imply or suggest any judgment about the fuel mix or emissions impact.

The commission declines to replace the term "scorecard," although the definition is modified in response to other comments pertaining to subsection (e). The commission does not believe that the term implies judgment; it merely implies a compilation of numbers into an easy-to-use format.

Public Citizen and Linda Hajek commented that in §25.476(c)(6), the commission should use the common terms for emissions. For example, "smog" for $NO_x$, "acid rain" for $SO_2$, "global warming" for $CO_2$ and "soot" for particulates. TXU replied that the format of the label was extensively discussed by parties and decided by the commission in Docket Number 22255, and that it was not appropriate to change the format in this rulemaking.

The commission declines to make the modifications to the terms for emissions. Although using the common terms may purport to provide the information to customers in a more understandable format, the commission finds that using the common terms may result in more customer confusion. Using the more scientific terms provides context for customers to find further information about emissions and to apply their own judgment.

TRPC commented that in subsection (c)(7), which defines fuel mix, the term "power" should be revised to "that portion of MWhs that derive from resources defined as renewable."

The commission declines to make TPRC's suggested change. The commission finds that the term "power" is clear and understandable.

ETEC commented that the provision of subsection (c)(11) that states "electric cooperative that owns or controls generating facilities in the State of Texas" is problematic. ETEC argued that for many hydro facilities, the federal government owns the facility; however, the electric cooperatives control the REC offset. Electric cooperatives are therefore concerned that they could lose the value of the REC offsets if the facility issued certificates of generation instead.

The commission believes that ETEC's main concern with this definition is obviated by the deletion of subsection (f). Related issues are discussed further in the commission's response to comments regarding Question Number 2 of May 18, 2001, and regarding subsection (g). The commission will determine how to address the issue of federal ownership when it considers the certificates of generation program in a future rulemaking.

*§25.476(d) - Marketing standards for "green" and "renewable" electricity products*

Comments concerning this section are summarized above, in the discussion regarding Question Number 3 of February 2, 2001.

*§25.476(e) - Compilation of scorecard data*

Many issues regarding the scorecards are addressed in the context of the specific questions summarized above. In addition to those comments, SPS said the commission should disclose the vintage as well as the source of the data used in the generator scorecard calculations.

TXU commented that generators should have an opportunity to review and comment on their scorecards prior to their dissemination, and that they should be based on data for the immediately preceding calendar year. Review and timely updates are necessary to reflect compliance with federal requirements that certain generating facilities reduce their nitrogen oxide and sulfur dioxide emissions, and TXU said further that the scorecards should reflect reasonably projected changes due to expected implementation of emissions reductions, changes in fuel use, or other operating changes. Scorecards should also be adjusted to reflect the sale of facilities. Environmental Defense disagreed with the use of projected changes, saying that TXU's proposal would open the door to misreporting and would require constant and ongoing verification by the commission.

The commission agrees with Environmental Defense that the scorecards should not include any projected changes. The emissions and fuel data must represent activity that is actual and measured. The commission also agrees with TXU that generators should have an opportunity for early review of their scorecard data and agrees with SPS that scorecards should include source and vintage of data. Subsection (e), as proposed, allows for scorecard adjustments due to new plants placed in operation and to retirement of plants previously in operation. Early review by generators may also detect administrative errors that spuriously affect the result. The commission therefore amends subsection (e) to ensure that generators have a month to inspect initial scorecard data prior to publication on the commission's web site.

While using data that generators are already reporting to other federal and state agencies will reduce the reporting burden, the commission reminds generators that it also has authority under PURA to require them to report data directly to the commission. TXU's request for using data from the previous calendar year illustrates some of the considerations the commission must balance. Emission-related data reported to federal agencies may take two or three years before they are included in a public database. Reporting directly to the commission may be the only way to reduce the lag time, but it may also increase the burden on generators. The ultimate consideration with respect to this rule is whether the information at hand is sufficient for meaningful disclosure to customers, and the commission finds that it is prudent to maintain flexibility with respect to data collection. To clarify this point, the commission amends subsection (e)(2) to reflect that it will use the "best available data" in compiling generator scorecards, allowing the commission flexibility to use other agencies' data or gather its own, as may be needed.

AEP objected to excluding renewable energy credits (RECs), REC offsets and certificates of generation from generator scorecards, and objected to publishing the scorecards on the commission's web site. It also raised a number of questions, among them: Are generators required to submit scorecards; does the generator have recourse if it disagrees with a scorecard; are there concerns about posting data for a generator that owns only one Texas facility; and how would multiple ownership be treated? In reply comments, Reliant agreed that the scorecards should not be published on the Internet, while Independent Marketers supported Internet publication of the scorecards. Reliant disagreed with AEP with regard to including RECs, REC offsets and certificates of generation on the scorecards, as other entities will have contracted specifically for the electricity represented by these instruments. Including them in the scorecard would result in double-counting, Reliant said.

TRPC suggested distinguishing between the "inaugural" scorecard and the adjusted scorecard. The inaugural or unadjusted scorecard would include all of a generator's resources, including those participating in the REC trading program. These initial scorecards would be published on the commission's web site. Power associated with RECs would be deducted from the initial scorecard along with the adjustment for certificates of generation.

The commission finds that TRPC's suggestion is reasonable, and subsection (e) is amended accordingly. A generator's initial scorecard, which shall reflect the company's entire Texas fleet of plants, shall be published on the commission's web site. The adjusted scorecard shall deduct certified REC generators and approved REC offset generators and shall appear only on the commission-approved spreadsheets used by REPs to calculate their Electricity Facts label disclosures. The commission also modifies the definition of "generator scorecard" to reflect a more general notion, relying on subsection (e) to establish the distinction between initial and adjusted scorecards.

LCRA said that the methodology used for plants with multiple owners may in some instances result in the misappropriation of environmental attributes. For example, the Sam Seymour/Fayette Power Project comprises three coal-fired units, two of which LCRA co-owns with the City of Austin. In the sample scorecard spreadsheet posted by the commission on its web site, the environmental attributes of Sam Seymour were distributed to LCRA and Austin Energy on the basis of capacity ownership. Because the environmental attributes of the three units differ, LCRA said, a simple pro-rata distribution would be inaccurate.

With respect to multiple ownership of generating facilities, it is the responsibility of the owners to inform the commission as to the most appropriate way to apportion a plant's output and emissions, whether by percentage ownership of the entire plant, by ownership of specific turbines or boilers at the plant, or by some other method indicative of actual ownership. This should be part of the generator's scorecard review process.

*§25.476(f) - Certificates of generation*

Austin Energy, Consumer Commenters and Environmental Defense advocated eliminating the certificates program from the rule. Austin Energy said it would create a loophole that would allow any retailer to represent all the products it marketed to residential and small commercial customers as being fueled by "green" natural gas. Noting that disclosure is required only for residential and small commercial customers, Austin Energy said Texas has sufficient natural gas generation for every Electricity Facts label to reflect a 100% "green" natural gas fuel mix. Consequently, customers would have no meaningful information to help them choose among suppliers on the basis of fuels used.

They also said tradable certificates would enable companies to misrepresent the attributes of the electricity products they sell to customers. Austin Energy, along with Brazos and ETEC, said it would be possible for a retailer to obtain all its power under a contract with a coal-fired generator, and use natural gas certificates to represent the product as coming from "green" natural gas.

Environmental Defense concluded that REPs would still be able to market products with specific fuel and environmental profiles by selectively entering into supply contracts with power generators. On the other hand, Austin Energy said that it would not be an adverse outcome if a more active wholesale market resulted in all disclosures looking more like the default scorecard. Austin Energy also advocated limiting product-specific disclosures to renewable products; otherwise, retailers would average the fuel mix and emissions of their suppliers and (for power coming from generation sources that are not reasonably traceable) the default scorecard.

Environmental Defense and Austin Energy also said the certificates program served no economic or policy purpose. Environmental Defense said that trading programs are designed to achieve mandated goals (installation of new renewable generation, emission reductions, automobile fuel efficiency) in the most cost-effective manner, but are not appropriate for product disclosures. Austin Energy said trading programs are intended to address market failures, but that it was unclear what market failure the certificates program would address.

Consumer Commenters said at the public hearing that they were in agreement with Environmental Defense and were especially concerned about the potential for gaming under the certificates program. The group said that if the program were to be used, it should be set up in such a way that gaming was not possible, because if consumers can not get a clear and accurate representation of the emissions of the products they are buying, then "we may as well just throw the whole emissions disclosure out the window."

The commission disagrees with Environmental Defense and Austin Energy regarding their comparison of the certificates program with emission trading programs. There is no quantifiable target or baseline involved with the certificates program, and therefore the cap-and-trade model is inapplicable and irrelevant. To the extent that the "green" attributes of generation have value to customers, certificates represent a way of capturing that market value in the form of a security and making the existing value more amenable to exchange. By contrast, cap-and-trade programs deal with economic externalities that are not being valued by the market, a situation the certificates program is not intended to address.

The commission notes that if there is an abundance of natural gas generation, there will probably be an abundance of "green" residential electricity offerings regardless of how a retailer's fuel mix is authenticated. Thus, Austin Energy's assertion that the certificates program will saturate the market with "green" offerings is unfounded. However, Environmental Defense correctly notes that due to the abundance of natural gas generation, retailers may not need certificates in order to assemble product offerings with different fuel mixes and emission profiles. Thus the question is whether a simple tracking of supply contracts will be sufficient to connect "green" generation with all customers who are willing to pay. Only experience will provide a definitive answer.

The commission believes the certificates concept is a viable tool to augment the market's ability to connect customers and generators. Many of the concerns raised by Environmental Defense, Austin Energy, and other parties would be resolved by limiting the applicability of certificates so that they could only replace generation that otherwise would be represented by the default scorecard. However, the commission is also mindful of concerns raised by Consumer Commenters that certificates may be confusing to customers. The commission is also concerned about the cost of the certificates program, a matter that was raised by several commenters. Supply contracts are straightforward; therefore, it is preferable to rely on them as the basis for disclosures. If experience shows that there are certain impediments, however, a certificates approach may be a useful remedy to augment a contract-based system. Therefore, the commission deletes subsection (f), but may revisit the concept once the full competitive market has had an opportunity to mature.

San Antonio supported the certificates program, saying that it provides the ability for market participants to avoid unnecessary and burdensome business procedures and contractual relationships which would otherwise be necessary. SPS and TXU suggested changing paragraph (3) to allow a certificate to account for all or a portion of a facility's output. TXU further suggested allowing REPs more flexibility in applying certificates to different products, eliminating the affidavit requirement, and calculating nuclear waste on the basis of average pounds of spent fuel per MWh produced during a specific fuel load cycle. AEP said that creating an anonymous exchange procedure would be costly, and that a simpler approach would be to register changes in ownership. AEP, ERCOT and Reliant also said the rule should specify who would pay the fees that would support the certificates program. Green Mountain, Independent Marketers and Environmental Defense said the commission should retain oversight with respect to user fees. Independent Marketers also said certificates should not be bound to a supply contract, that generators must be required to register a certificate with the program administrator before it could be sold, and that a specific date should be set for the selection of a program administrator. TXU disagreed, however, and argued that market participants should have the flexibility to package energy and certificates as needed. TXU also said there should be no restriction on when certificates could be sold as long as their registration and retirement were in compliance with other provisions of the rule.

The various revisions suggested by parties relate to issues that will be more clearly defined once full competition begins. Because the commission is not adopting a certificates process now, these issues need not be addressed now.

*§25.476(g) - Calculating fuel mix and environmental impact disclosures*

AEP said that RECs should not be used to validate renewable claims. Instead, renewable power should be authenticated just as provided in the proposed rule for all other sources of power: either by supply contract or by a certificate of generation. AEP said the REC trading program was established to meet the renewable energy capacity requirements of Senate Bill 7 (76th Legislature), and that RECs and REC offsets were intended to be traded separately from the energy bought and sold in the wholesale market. Environmental Defense disagreed with AEP's suggestion, however, noting that by definition a REC represents a megawatt of renewable energy that is actually produced, metered and verified. Reliant, also disagreeing with AEP, said not recognizing RECs for disclosure purposes has the potential to dilute the value of the REC market, thereby discouraging renewable energy development in Texas. Reliant said the REP retiring the REC has obviously purchased the REC and is therefore entitled to take credit for it.

The commission disagrees with AEP. If RECs were excluded from the disclosure calculus and only contracts were used, a REC purchaser could actually subsidize a competitor's ability to market renewable power. Using RECs as the sole means of authenticating power from certified renewable energy credit generators is the best way to prevent this unfair distortion of the market. This approach fulfills the Legislature's intent with regard to developing renewable energy in Texas and provides customers with credible assurance that their money is being used to support renewable resources.

However, the commission also acknowledges the confusion that may arise from reading §25.173(p), concerning renewable resources eligible for sale in the Texas wholesale and retail markets, alongside this subsection. The commission notes that subsection (p) is the only part of §25.173 that does not pertain directly to the renewable energy credit trading program. Moreover, §25.173(p) was written and adopted before the Electricity Facts label was created. Issues regarding the marketing of renewable energy to customers are adequately and appropriately addressed in the context of customer protection, which is the purpose of §25.476. For these reasons, the commission finds that §25.173(p) should be superceded by §25.476. It is the intent of the commission to propose amending §25.173 to delete subsection (p) in a future rulemaking.

AEP also said that if the commission decides to retain RECs as a means of authentication, then REC offsets should also be used. TRPC said, however, that the subsection should be clarified to reflect that a REC offset may not be used, but that the actual production and emissions associated with the offset should. Environmental Defense said offsets should not be used because they were created for a different purpose: to provide a fixed adjustment to allocated REC requirements based on existing renewable energy generation. By contrast, disclosures under the proposed rule ought to rely on the actual production of renewable energy.

There may be some confusion regarding the nature of REC offsets. TRPC and Environmental Defense correctly note that offsets do not describe current output and, therefore, are not appropriate for customer disclosure. An offset is associated with ownership of or a supply contract from existing renewable energy facilities. Subsection (g)(4) as proposed provides that an offset "may be used to authenticate the renewable attributes of its associated supply contract." Thus, the output of a REC offset generator may be counted as renewable energy for the purposes of customer disclosure. No revision is necessary, other than to expand the language of this paragraph to include ownership of the facility.

TXU recommended changes that would allow fuel and emissions information to be apportioned between products on something other than a per-MWh basis. In reply comments, Green Mountain agreed, while Environmental Defense said TXU's proposal would unnecessarily complicate the labeling disclosure process and should be rejected. AEP recommended deleting the requirement that each label reflect a certain number of RECs, saying that it goes beyond the provisions of the customer protection rules.

A number of commenters responded to the provision limiting affiliated REPs to one fuel and environmental impact profile for all Price-to-Beat products it offers in its affiliated service area. AEP and TXU said the provision should be deleted. Green Mountain and Independent Marketers said it should remain.

The Legislature clearly intended the Price-to-Beat to be a constraint on affiliated REPs, with the power of incumbency held in check for the first years of choice so that competitive retailers could establish footholds in the newly opened markets. To allow affiliated REPs flexibility to offer "green" price-to-beat products alongside standard price-to-beat products would run counter to the Legislature's intent. However, as TXU notes, the commission has provided for unique "green" or "renewable" price-to-beat offerings if the utility had a renewable energy tariff on January 1, 1999. Subsection (g)(8) is therefore amended to specify that a special Price-to-Beat label is permissible only if there was a renewable tariff in place on January 1, 1999.

TXU recommended other clarifying editorial changes in this subsection: replacing "purchased" with "acquired" throughout the section to reflect that REPs may obtain power from generators other than through purchases; and specifying that scorecards are associated not with a REP but with the generator from which the REP acquires power through a supply contract. It also suggested changing the due date for Electricity Facts label updates from April 1 to 30 days after the commission posts the adjusted scorecards.

The commission agrees with TXU with respect to acquired power, the accurate association of scorecards, and the due date for updated Electricity Facts labels, and incorporates these changes. To simplify the timeline, however, the commission adopts beginning-of-month due dates for REP supply reports and Electricity Facts label updates.

TXU also expressed concern that the commission's proposed standard for compliance is inflexible and may be unattainable for reasons outside the control of the REP. TXU surmised that there will be differences between posted scorecards and actual performance over the course of a year. To accommodate those differences and to create flexibility, TXU recommended that the commission modify the language in proposed subsections (g)(9) and (h) from an "at least as favorable" standard to a "not materially inconsistent" standard. First, TXU questioned whether "at least as favorable" means that the actual performance must result in lower emissions and more gas or renewable fuels than reported on the EFL (or precisely the same as reported). TXU provided two examples. First, if consumers' preferences change such that over the course of a year they switch from one product to another or buy more or less of a product, the actual generation required to serve them may be significantly different from what was anticipated. TXU contended that such changes in customers' preferences would be completely beyond the retailer's control and easily could result in actual performance being not as favorable as the initial EFLs. TXU provided a second example that, over time, more and more generation or green generation will be used; therefore, more and more RECs and certificates of generation will be employed resulting in the Texas-wide default scorecard becoming "dirtier" each year. TXU noted that a retailer which chooses to sell only system power would report on its EFL the previous years' default scorecard data, but for the subsequent year the actual performance of the system power generators would probably not be "at least as favorable" as the previous year, due to increasing use of renewable and green power. Therefore, TXU argued that through no fault of its own, such retailers could be in violation of the "at least as favorable as" standard every succeeding year. Instead, TXU recommended that the commission modify its standard to reflect that the retailer's performance should not be materially inconsistent with the EFLs of the retailer's electricity products. TXU argued that the "not materially inconsistent" standard would protect consumers from being misled while allowing room for non-material, inevitable deviation. TXU provided its recommended language modifications. In reply comments, Green Mountain and Independent Marketers concurred with using the phrase "not materially inconsistent with."

The commission agrees with TXU that the "at least as favorable" standard of compliance means that the actual performance of the retail provider must result in precisely the same or lower emissions than reported on the EFL. In other words, the actual performance must be precisely the same or incorporate more natural gas or renewable fuels than reported on the EFL. The commission declines to make any modification to the provision as it plainly expresses the commission's intent. In order to encourage retailers to exercise due diligence in their acquisition of power throughout the year so that their fuel mix is what the retailer projected, the commission purposefully selected a clear, bright-line standard. Achieving this standard is by no means out of the retailer's control; the retailer has full discretion over the numbers it chooses for its projection and over how it acquires supplies over the course of the year being projected. The commission declines to incorporate TXU's recommended language because the meaning of "materially inconsistent" is ambiguous. The retail provider's EFL must correctly reflect the retailer's electricity products. The commission does not disagree that consumers' preferences may change over the course of a year and that consumers may switch between different product mixes. However, retailers' use of contracts is within their direct control as the marketing of the product. The commission desires to promote the availability of informative, accurate, useful information to the retail customers of Texas.

*§25.476(h) - Special provisions for the first year of competition*

TXU asserted that the use of a two-prong methodology to distinguish between a competitive retailer and affiliated REP is discriminatory. TXU argued that to assume that affiliated REPs will acquire all the power they sell from their affiliated PGC is based on an incorrect assumption. TXU urged that all retailers should use the projection approach.

TXU, Green Mountain, and Enron proposed that the commission replace the phrase "at least as favorable as" with the phrase "not materially inconsistent with."

The commission agrees with TXU that affiliated REPs and competitive retailers should be treated the same with respect to the first year of competition, and subsection (h) is amended accordingly. However, the commission declines to drop the "at least as favorable" standard, for reasons previously set forth in this preamble.

*§25.476(i) - Compliance and enforcement*

ETEC questioned the commission's jurisdictional authority over co-ops when considering the limitations of PURA §41.004. ETEC questioned whether the proposed reporting and filing requirement is enforceable against co-ops or MOUs, questioned whether the commission has jurisdictional authority to require co-ops to label generation sources to its members or customers, and questioned the proposed provisions that address labeling for a co-op that has not opted into retail competition or that opts into retail competition but chooses to compete only within its service territory.

With regard to proposed §25.476(i)(1), ETEC questioned whether an advisory to the media does anything other than incite a war of words if the commission has no real enforcement authority and the co-op believes it did nothing wrong and refuses to change its practices. ETEC believed that the commission does not have the jurisdiction to control the co-op's advertising, marketing, and information activities and therefore recommended the commission adopt a modified version which states that the rule does not affect co-ops and that REC offsets are not instruments that can be converted into generation certificates.

Both San Antonio and Austin Energy objected to §25.476(i)(1) because allowing the commission to issue an advisory to local news media is beyond those specific enforcement action remedies allowed for anti-competitive actions by an MOU under PURA Chapter 40. Austin Energy further commented that, for other violations, the commission should alert the governing board or municipal body which has oversight authority of the utility in question because those bodies are responsible for the actions of the utilities and are responsive to the customer-citizens of those entities. San Antonio argued that PURA §40.056 prescribes a specific enforcement process, involving the receipt of a complaint, notice, and the right to a hearing. Following a hearing, if required, and upon a finding that the complaint is valid, the commission must provide the MOU three months to cure the anticompetitive or noncompliant behavior. Finally, following the three-month period, the commission may then prohibit the MOU from providing retail service outside its certificated retail service area until the rule, action, or order is remedied. San Antonio supported the statutory provisions as appropriate because San Antonio believed that the rule will apply to municipally owned utilities and cooperatives only to the extent that they are participating in retail competition outside their traditional service areas.

TXU commented that proposed subsection (i) grants the commission greater enforcement authority than allowed under PURA §§39.101(e), 39.356, and 39.357 in that the proposed language allows the commission to take any corrective action while PURA limits the commission to specific remedial powers and provides the specific remedies the commission may use. TXU recommended that in subsection (i)(1), the phrase "shall order the REP to take corrective action as necessary" be deleted and replaced with "may take remedial action consistent with PURA §§39.101(e), 39.356, or 39.357."

STEC pointed to PURA §17.006 and argued that the commission may enforce its customer protection rules only for customers served by an electric cooperative outside its certificated area. Instead, STEC argued, it is the board of directors of an electric cooperative which has the sole jurisdiction to enforce customer protection rules for customers served within its certificated area. Thus, STEC concludes that §25.476(i) does not comport with PURA. STEC argued that the provisions, as proposed, allow the commission to interfere with the board of director's jurisdiction regarding customers within its certificated service area. Even though the remedial actions permitted under the rule are for the commission to inform the electric cooperative's board of directors and general manager of a violation and issue an advisory to the local media, STEC regarded the proposed rule as imposing the commission's labeling rule on electric cooperatives serving customers within their certificated service areas. Consequently, STEC recommended that subsection (i) apply only to competitive retailers and to affiliated REPS and recommended that references in subsection (i) to municipally-owned utilities or electric cooperatives be deleted.

The commission agrees with ETEC, San Antonio, Austin Energy, and STEC that an advisory to the local media may not be the most appropriate remedy for correcting anti-competitive activity. The commission modifies this portion of its rule in response to these comments.

The commission disagrees with TXU that subsection (i) grants the commission greater enforcement authority than allowed under PURA §§39.101(e), 39.356, and 39.357 in that the proposed language allows the commission to take any corrective action. However, the commission agrees that the wording of the proposed rule could be ambiguous. Therefore, in response to TXU's comments, the commission modifies subsection (i)(1) to delete the phrase "shall order the REP to take corrective action as necessary" and replaces with "may take remedial action consistent with PURA §§39.101(e), 39.356, or 39.357."

STEC agreed with the commission that the rule should not provide a competitive retailer or an affiliated REP protection against prosecution under the deceptive trade practices act (DTPA). However, STEC commented that the proposed rule allows for a violation of the DTPA because it allows the competitive retailer or REP to purchase all of its power for resale from facilities using coal or lignite, and to purchase certificates of generation at a cost significantly less than the cost of renewable energy. STEC commented that such an arrangement would mislead the retail customer into believing that all of its power is generated through the use of renewable resources. STEC further asserted that the information provided to the customer on emissions and waste per kWh generated will be false because the customer will be provided information on the emissions from the use of renewable resources rather than emission information on the use of coal and lignite. STEC believed that, in most instances, the competitive retailer will also charge the misled retail customer more for its power because of the environmental benefits associated with renewable energy. STEC claimed that many people believe such practice is a violation of the DTPA. STEC referred to PURA §17.004 and §39.101 and asserted that the intent of the Legislature is to provide to customers correct information regarding the impact the power they choose to purchase will have on the environment. STEC recommended that the rule allow the retail customer to distinguish between renewable power generated from renewable resources and renewable power occasioned by the labeling rule under the certificates of generation program. STEC further recommended that the rule be amended so that the most unsophisticated retail customer can determine whether it is purchasing actual renewable energy or only energy labeled renewable because of the certificates of generation program.

Similarly, Brazos was concerned about the apparent deceptiveness of the entire proposed rule because it allows competitive retailers and affiliated REPS to represent to consumers that by purchasing certificates "brown" generators produce "green" power and that fossil fuel generators are "renewable" resources. Brazos also noted that the provision in proposed §25.476(g)(9)(D) relating to the DTPA appears to apply only to new products' projected sales. Brazos questioned why the provision is needed at all and, if needed, why the provision does not apply to the remaining subsections. Finally, Brazos recommended that the commission reject the proposed rule.

Although the DTPA was not mentioned in its comments, Environmental Defense did suggest that allowing companies to use tradable certificates of generation on a voluntary basis allows companies to misrepresent their product attributes because the companies are able to easily disguise the true nature of their electricity product. Environmental Defense suggested that because emissions and fuel certificates would not be scarce, the use of the certificates would not provide any means to actually affect the portfolio of electric generating resources in the State.

As previously explained, the commission finds that direct supply contracts with generators are the preferred means of authenticating the attributes of power initially sold by retailers to customers.

It may consider a certificates program if experience suggests that it is a better approach. Issues relating to a certificates program are more appropriately addressed if and when the commission chooses to implement it.

However, the commission agrees in part with Brazos regarding the application of the DTPA provision to the entire rule. The commission acknowledges that the DTPA remains a separate cause of action available to those who qualify to take action under the Act. Anyone eligible under the DTPA to bring a claim may do so. In response to Brazos' comment, the commission will delete the provision in §25.476(g)(9)(D) and will instead make it applicable to the entire section by inserting it in subsection (b) entitled Applicability.

All comments, including any not specifically referenced herein, were fully considered by the commission. In adopting this section, the commission makes other minor modifications for the purpose of clarifying its intent.

This section is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2001) (PURA) which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; and specifically, PURA §39.101 which grants the commission authority to establish various specific protections for retail customers, including entitling customers to have information concerning the environmental impact of certain production facilities, and information sufficient to make an informed choice of electric service provider; §39.9044 which grants the commission authority to establish rules allowing and encouraging competitive retailers to market electricity generated using natural gas produced in this state as environmentally beneficial; and PURA Chapter 17, Subchapter A, which authorizes the commission to adopt rules to protect retail customers and requires the commission to promote public awareness of changes in the electric utility market.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.002, 14.052, 39.101, 39.9044, and Chapter 17, Subchapter A.

*§25.476. Labeling of Electricity with Respect to Fuel Mix and Environmental Impact.*

(a) Purpose. The purpose of this section is to establish the procedures by which competitive retailers calculate and disclose information on the Electricity Facts label pursuant to §25.475 of this title (relating to Information Disclosures to Residential and Small Commercial Customers).

(b) Application.

(1) This section applies to all competitive retailers and affiliated retail electric providers (affiliated REPs) as defined in §25.471(d) of this title (relating to General Provisions of Customer Protection Rules). Additionally, some of the reporting requirements established in this section apply to all owners of generation assets as defined in subsection (c) of this section.

(2) Nothing in this section shall be construed as protecting a competitive retailer or affiliated REP against prosecution under deceptive trade practices statutes.

(3) In accordance with PURA §39.001(b)(4), the commission will protect the competitive process in a manner that ensures the confidentiality of competitively sensitive information during the transition to a competitive market and after the commencement of customer choice.

(c) Definitions. The definitions set forth in §25.471(d) of this title apply to this section. In addition, the following words and terms, when used in this section, shall have the following meanings unless the context indicates otherwise:

(1) Authenticated generation - Generated electricity with quantity, fuel mix, and environmental attributes accounted for by a retired renewable energy credit (REC), or supply contract between a competitive retailer or affiliated REP and an owner of generation assets, to be used in calculating the retailer's Electricity Facts label disclosures.

(2) Default scorecard - The estimated fuel mix and environmental impact of all electricity in Texas that is not authenticated as defined in paragraph (1) of this subsection.

(3) Electricity Facts label - A standardized format, as described in §25.475(e) of this title, for disclosure information and contract terms made available to customers to help them choose a provider and an electricity product.

(4) Electricity product - A product offered by a competitive retailer or affiliated REP to a customer for the provision of retail electric service under specific terms and conditions, and marketed under a specific Electricity Facts label.

(5) Environmental impact - The information that is to be reported on the Electricity Facts label under the heading "emissions and waste per kWh generated," comprising indicators for carbon dioxide, nitrogen oxides, particulates, sulfur dioxide, and spent nuclear reactor fuel. For the purposes of this section, environmental impact refers specifically to emissions and waste from generating facilities located in Texas, except as provided in subsection (f)(3) of this section.

(6) Fuel mix - The information that is to be reported on the Electricity Facts label under the heading "sources of power generation." The fuel mix shall be the percentage of total MWh obtained from each of the following fuel categories: coal and lignite, natural gas, nuclear, renewable energy, and other known sources. Renewable energy shall include power defined as renewable by the Public Utility Regulatory Act (PURA) §39.904(d).

(7) Generator scorecard - The aggregated fuel mix and environmental impact of all generating facilities located in Texas that are held by the same owner of generation assets.

(8) New product - An electricity product during the first year it is marketed to customers.

(9) Other generation sources - A competitive retailer's or affiliated REP's supply of generated electricity that is not accounted for by a direct supply contract with an owner of generation assets.

(10) Owner of generation assets - A power generation company, river authority, municipally owned utility, electric cooperative, or any other entity that owns or controls generating facilities in the state of Texas.

(11) Renewable energy credit (REC) - A tradable instrument representing the generation attributes of one MWh of electricity from renewable energy sources, as authorized by PURA §39.904 and implemented under §25.173 of this title (relating to the Goal for Renewable Energy).

(12) Renewable energy credit offset (REC offset) - A non-tradable allowance as defined by §25.173(c)(10) of this title and created by §25.173(i) of this title. For the purposes of this section, a REC offset authenticates the renewable attributes, but not the quantity, of generation produced by its associated facility.

(d) Marketing standards for "green" and "renewable" electricity products.

(1) A competitive retailer or affiliated REP may market an electricity product as "green" only in the following instances:

(A) All of the product's fuel mix is renewable energy as defined in PURA §39.904(d), Texas natural gas as specified in PURA §39.9044(d)(2), or a combination thereof, and

(B) All statements representing the product as "green," if not containing 100% renewable energy, as defined in PURA §39.904(d), shall include a footnote, parenthetical note, or other obvious disclaimer that "A 'green' product may include Texas natural gas and renewable energy. See the Electricity Facts label for this product's exact mix of renewable energy and Texas natural gas."

(2) A competitive retailer or affiliated REP may market an electricity product as "renewable" only in the following instances:

(A) All of the product's fuel mix is renewable energy as defined in PURA §39.904(d); or

(B) All statements representing the product as "renewable" use the format "x% renewable," where "x" is the product's renewable energy fuel mix percentage.

(3) If a competitive retailer or affiliated REP makes marketing claims about a product's "green" content on the basis of its use of natural gas as a fuel, the competitive retailer or affiliated REP must include with the report required under subsection (f)(1) of this section proof that the natural gas used to generate the electricity was produced in Texas.

(e) Compilation of scorecard data.

(1) The commission will create and maintain a database of generator scorecards reflecting each owner of generation assets' company-wide fuel mix and environmental impact data based on generating facilities located in Texas. These scorecards shall be used by competitive retailers and affiliated REPs in determining the fuel and environmental attributes of electricity sold to retail customers.

(2) Initial generator scorecards based on the best available data will be published on the commission's internet web site and shall state:

(A) MWh obtained from each fuel source (coal and lignite, natural gas, nuclear, renewable energy, and other sources), and the corresponding percentages of total MWh;

(B) tons of carbon dioxide, nitrogen oxides, particulates, sulfur dioxide, and spent nuclear fuel produced (with spent nuclear fuel annualized using standard industry conversion factors), and the corresponding emission rates in tons per MWh; and

(C) sources from which data were obtained, including year of publication and year of generation.

(3) Each generator will have one month to review its initial scorecard data prior to publication on the commission's web site. The commission will accept changes reflecting retirement of facilities, the addition of new facilities, the sale or purchase of facilities, verified changes in a facility's emission rates and fuel use, and the correction of administrative errors.

(4) Not later than March 1 and September 1 of each year, the commission will adjust all generator scorecards to deduct the MWh and associated attributes of:

(A) power for which a REC has been issued; and

(B) power from facilities that have been designated by the commission as REC offset generators.

(5) Not later than March 1 and September 1 of each year, the commission will calculate a combined scorecard for all generating units whose capacity will be auctioned under §25.381(e)(1)(A) of this title (relating to Capacity Auctions), and a combined scorecard for all generating units whose capacity will be auctioned under §25.381(e)(1)(B)-(D) of this title.

(6) Not later than March 1 and September 1 of each year, the commission will calculate a default scorecard to account for all electric generation in the state that is not authenticated as defined in subsection (c)(1) of this section.

(A) The default fuel mix shall be the percentage of total MWh of generation not authenticated that has been obtained from each fuel type.

(B) Default emission rates for each environmental criterion shall be calculated by dividing total tons of emissions or waste by total MWh, using data only for generation not authenticated.

(7) The commission will include the adjusted generator scorecards, capacity auction scorecards and the default scorecard on the reporting forms to be used by competitive retailers and affiliated REPs to calculate their Electricity Facts label disclosures. The adjusted generator scorecard shall include a statement that the data may differ from the unadjusted scorecard and shall include a reference to the commission's web site for additional information.

(f) Calculating fuel mix and environmental impact disclosures.

(1) Not later than February 1 and August 1 of each year, each competitive retailer and affiliated REP shall report to the commission the following information for the previous six-month period ending December 31 or June 30:

(A) all owners of generation assets, other entities and capacity auctions from which the competitive retailer or affiliated REP purchased electricity for delivery to customers during the previous calendar year and the MWh obtained from each supplier, with sources that together supplied less than 5.0% of the competitive retailer's electricity combined and treated as other generation sources;

(B) MWh sold under each electricity product offered by the competitive retailer or affiliated REP during the previous calendar year; and

(C) attestations from power generators that the natural gas used to generate electricity supplied to the competitive retailer or affiliated REP was produced in Texas, if the competitive retailer or affiliated REP intends to market "green" electricity on the basis of that power.

(2) Not later than April 1 and October 1 of each year, each competitive retailer and affiliated REP shall calculate its fuel mix and environmental impact for the previous six-month period ending December 31 or June 30. Calculations shall include a disclosure that aggregates all electricity products offered by the competitive retailer, and specific disclosures for each electricity product. Disclosures provided on an Electricity Facts label shall describe a specific electricity product sold to customers during the previous six-month period ending December 31 or June 30, except as provided in paragraph (9) of this subsection.

(3) For power purchased from sources outside of Texas, a supply contract between a competitive retailer or affiliated REP and the owner of a generating facility may be used to authenticate fuel mix and environmental impact claims.

(A) The contract must identify a specific generating facility from which the competitive retailer or affiliated REP is to obtain electricity.

(B) The competitive retailer or affiliated REP shall include fuel mix and environmental impact information for the specified generating facility in its report to the commission pursuant to paragraph (1) of this subsection. Data shall come from the same sources used by the commission as reported pursuant to subsection (e)(2)(C) of this section. If the generating facility is not included in any database used by the commission, the retailer and the generating facility owner may provide other comparable public data that have been reported to a federal or state agency for the specified facility.

(4) For the purposes of disclosures on the Electricity Facts label, the retirement of RECs shall be the only method of authenticating generation for which a REC has been issued in accordance with §25.173 of this title. The retirement of a REC shall be equivalent to one megawatt-hour of generation from renewable resources. The use of RECs to authenticate the use of renewable fuels on the Electricity Facts label must be consistent with REC account information maintained by the Renewable Energy Credits Trading Program Administrator. A REC offset may be used to authenticate the renewable attributes of the current MWh output from its associated supply contract.

(5) A competitive retailer's or affiliated REP's company fuel mix shall be the MWh- weighted average of the fuel mixes represented by the adjusted scorecards of its suppliers, scorecards for successfully bid capacity auctions, out-of-state supply contracts, retired RECs, REC offsets and the default scorecard. MWh from generation sources not authenticated in accordance with this section shall be represented by the fuel mix of the default scorecard.

(6) A competitive retailer's or affiliated REP's company environmental impact shall be the MWh-weighted average of the emission rates represented by the adjusted scorecards of its suppliers, scorecards for successfully bid capacity auctions, out-of-state supply contracts, retired RECs, REC offsets and the default scorecard. Emissions of MWh from generation sources not authenticated in accordance with this section shall be represented by the default scorecard. The weighted average of each category of environmental impact shall then be indexed by dividing it by the corresponding state average emission rate and multiplying the result by 100.

(7) If a competitive retailer or affiliated REP offers multiple electricity products that differ with regard to the fuel mix and environmental impact disclosures presented on the Electricity Facts labels, the retailer:

(A) may apply any supply contract to the calculation of any product label as long as the sum of MWh applied does not exceed the MWh acquired under the contract; and

(B) may apply any number of RECs to the calculation of any product label as long as:

*(i)* the number of RECs applied to all product labels is consistent with the number of RECs the retailer has retired with the REC Trading Program Administrator, and

*(ii)* the number of RECs applied to each product label results in a renewable energy content for each product that is equal to or greater than a benchmark to be calculated from data maintained by the REC Trading Program Administrator. The benchmark shall be defined on an annual basis as:
Figure: 16 TAC §25.476(f)(7)(B)(ii)

(8) An affiliated REP shall use only one fuel mix and environmental impact disclosure for all price-to-beat products sold to residential and small commercial customers of its affiliated transmission and distribution utility, except that if the predecessor bundled utility had an approved renewable energy tariff in accordance with §25.251 of this title (relating to Renewable Energy Tariff) on file with the commission during the freeze on existing retail base rate tariffs established by PURA §39.052, the affiliated REP may sell a renewable Price-to-Beat product.

(9) A competitive retailer or affiliated REP may anticipate the fuel mix and environmental impact of a new product and adjust the disclosures for its existing products to account for the new product's projected sales.

(A) On the fuel mix disclosure of a new product's Electricity Facts label, the heading "Sources of power generation" shall be replaced with "Projected sources of power generation."

(B) On the environmental impact disclosure of a new product's Electricity Facts label, the heading "Emissions and waste per kWh generated" shall be replaced with "Projected emissions and waste per kWh generated."

(C) The competitive retailer or affiliated REP shall exercise due diligence in its acquisition of purchased power throughout the year so that the fuel mix and environmental impact authenticated at the end of the year is at least as favorable as what the retailer projected.

(D) A projected fuel mix may be used only for new products, and the projections may not change during the year except as provided in subparagraph (E) of this paragraph.

(E) At the end of the first six months that a new product is offered, a retailer may choose to authenticate the product's fuel mix and environmental impact according to the provisions of this section and delete the word "projected" from the Electricity Facts label.

(g) Special provisions for the first year of competition. Each competitive retailer and affiliated REP shall estimate the fuel mix and environmental impact of its electricity products offered to customers during the first year of competition, and shall exercise due diligence in its power acquisitions throughout the year so that the fuel mix verified at the end of the year is at least as favorable as what was projected.

(h) Compliance and enforcement.

(1) If the commission finds that a REP, other than a municipally owned utility or an electric cooperative, is in violation of this section, the commission may take remedial action consistent with PURA §§39.101(e), 39.356, or 39.357, and the REP may be subject to administrative penalties pursuant to PURA §15.023 and §15.024. If the commission finds that an electric cooperative or a municipally owned utility is in violation, it shall inform the cooperative's board of directors and general manager, or the municipal utility's general manager and city council.

(2) If the commission finds that a REP, other than a municipally owned utility or an electric cooperative, repeatedly violates this section, and if consistent with the public interest, the commission may suspend, restrict, deny, or revoke the registration or certificate, including an amended certificate, of the REP, thereby denying the REP the right to provide service in this state.

(3) The commission shall coordinate its enforcement efforts regarding the prosecution of fraudulent, misleading, deceptive, and anticompetitive business practices with the office of the attorney general in order to ensure consistent treatment of specific alleged violations.

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 September 26, 2001.

TRD-200105846
Rhonda G. Dempsey
Rules Coordinator
Public Utility Commission of Texas
Effective date: October 16, 2001
Proposal publication date: May 18, 2001
For further information, please call: (512) 936-7308

♦ ♦ ♦

# CHAPTER 26. SUBSTANTIVE RULES APPLICABLE TO TELECOMMUNICATIONS SERVICE PROVIDERS

# SUBCHAPTER R. PROVISIONS RELATING TO MUNICIPAL REGULATION AND RIGHTS-OF-WAY MANAGEMENT

## 16 TAC §26.465

The Public Utility Commission of Texas (commission) adopts amendments to §26.465, relating to Methodology for Counting Access Lines and Reporting Requirements for Certificated Telecommunications Providers, with changes to the proposed text as published in the April 6, 2001 issue of the *Texas Register* (26 TexReg 2613). The adopted amendment is necessary to implement House Bill 1777, 76th Legislature, Regular Session (1999) (HB 1777) which authorizes the commission to determine a uniform method for calculating municipal franchise compensation paid by certificated telecommunications providers (CTPs). The amendment clarifies which access lines are subject to HB 1777, specifying its application to include lines that pass through municipalities but do not terminate with end-use customers with regard to the use of public right-of-way (ROW) by CTPs. The amendment is adopted under Project Number 22909.

The commission withdraws from consideration proposed new §26.469, relating to Public Right-of-Way Fees and Penalties.

A public hearing for the taking of oral comments on the proposed amendments was held at the commission's offices on June 21, 2001 at 10:00 a.m. To the extent that the oral comments submitted during the public hearing differed from those submitted in writing, such comments are summarized herein.

The commission received written or oral comments from Texas Coalition of Cities for Utility Issues (TCCFUI); Texas Statewide Telephone Cooperative, Inc. (TSTCI); City of Garland (Garland); WorldCom, Inc. (WorldCom); City of Plano (Plano); Level 3 Communications, L.L.C. (Level 3); City of Houston (Houston); GTE Southwest Incorporated d/b/a Verizon Southwest (Verizon); Southwestern Bell Telephone Company (SWBT); AT&T Communications of Texas, L.P. (AT&T); Texas Municipal League and the Texas City Attorneys Association (TML); CLEC Coalition, including for the purposes of these comments, El Paso Global Networks Company, e.spire Communications, Inc., Global Crossing Local Services, Inc., Intermedia Communications, Inc., Qwest Communications Corp., and Time Warner Telecom of Texas, Ltd. (CLEC Coalition); the State of Texas; Texas Coalition of Cities, including the Cities of Addison, Austin, Bedford, Colleyville, El Paso, Farmers Branch, Grapevine, Hurst, Keller, Missouri City, North Richland Hills, Pasadena, Tyler, Westlake, West University Place, and Wharton (Coalition of Cities); Central Telephone Company of Texas d/b/a Sprint and United Telephone Company of Texas, Inc., d/b/a/ Sprint (Sprint); City of San Antonio (San Antonio); City of Leon Valley (Leon Valley); McLeodUSA Telecommunications Services, Inc. (McLeodUSA); and the City of Irving, individually and as adopting the position of TCCFUI (Irving). In addition to these, persons representing City of Dallas; Grande Communications; CCG Consulting; Southwest Competitive Telecommunications Association (SWCTA); and Smith, Majcher, and Mudge, L.L.P. attended the public hearing, but entered no testimony. The public hearing attendance list was filed in the commission's Central Records Division on June 22, 2001 under Project Number 22909.

The commission fully considered all written and oral comments.

*§26.465, Methodology for Counting Access Lines and Reporting Requirements for Certificated Telecommunications Providers*

The proposed amendments to §26.465(d)(1)(C) and §26.465(f)(5) clarify which access lines are subject to HB 1777, specifying its application to include lines that pass through municipalities but which do not terminate at an end-use customer's premises within that municipality, including interoffice transport and other transmission media that do not terminate at an end-use customer's premises in accordance with Texas Local Government Code §283.056(f).

GENERAL SUPPORT OF §26.465

The following parties filed written comments in general support of the commission's proposed amendment to §26.465: TSTCI, SWBT, Sprint, Verizon, AT&T, WorldCom, CLEC Coalition, Level 3, and McLeodUSA. In response to the comments submitted by other parties, AT&T referenced the arguments and authorities it previously submitted in brief on November 29, 2000. The State of Texas also filed written comments in support of the commission's proposed amendment to §26.465.

*State of Texas*

The State of Texas agreed with the commission's interpretations of Texas Local Government Code, Chapter 283 and with the commission's proposed clarification amendments to the substantive rules.

*Industry*

TSTCI generally supported the proposed rule, as written. TSTCI characterized §26.465(f)(5) as a good clarification of the rule.

SWBT supported the commission's amendment to §26.465 because the amendment restates, correctly reflects, and further clarifies the law as stated in Texas Local Government Code §283.056(f). SWBT specifically supported the amendment to §26.465(f)(5) on the grounds that it clarifies the compensation limitations of Chapter 283.

Sprint commented that the amendments to §26.465 represent a fair standard with which to interpret the intent of HB 1777, to make clear which access lines are subject to the provisions of HB 1777, and to fairly identify what fees and penalties can and cannot be assessed by cities. Sprint asserted that the proposed rule strikes a fair balance between municipal interests and the enhancement of competition.

Verizon supported the amendment to §26.465.

AT&T described proposed §26.465 as a proper interpretation of Chapter 283, both as to the intent of the law and the actual statutory provisions.

WorldCom welcomed the proposed amendment to clarify the status of pass-through lines.

The CLEC Coalition supported the adoption of the proposed amendment to §26.465 and urged the commission to adopt the proposed amendment.

McLeodUSA stated that it supported the amendments to §26.465 regarding pass- through lines and agreed with the CLEC Coalition's assessment of the proposed language in comments.

GENERAL OPPOSITION TO §26.465

The following cities and city representatives filed written comments in general opposition to the commission's proposed amendment to §26.465: TML, TCCFUI, Plano, San Antonio, Houston, Garland, Coalition of Cities, and Leon Valley. Irving offered oral comments at the public hearing. However, TML supported proposed subsection (f)(5).

*Municipalities*

TML urged the commission to delete the amendatory language proposed for §26.465(d)(1)(C).

TCCFUI stated that it concurred with the comments filed by TML and many of the cities and noted that those comments point out real harm that will occur if the amendment to §26.465 is passed.

Plano opined that the adoption of the proposed amendment to §26.465 would contradict the approach espoused by the commission in the October 21, 1999 Order adopting §26.463.

Leon Valley objected to "the proposed amendment to Local Government Code (LGC): a. 283.056(f), as given in. . . §26.465(d)(1)(C); and b. (f) lines not to be counted. (5)."

Garland urged the commission to reject the proposed revisions. Garland supported the comments filed by TCCFUI, Plano, Houston, TML, Coalition of Cities, San Antonio, and Leon Valley.

ARGUMENTS FOR AND AGAINST THE AMENDMENTS TO §26.465

*Full Compensation and Access Line Definition*

Parties submitted comments as to whether the amendment successfully implements "full compensation" to the cities for use of the public ROW, as intended by HB 1777, or rather, implements only a limited, incomplete amount of compensation for the various telecommunications facilities placed within the cities' public ROW. The appropriate definition as to what constitutes an "access line" as it relates to the compensation scheme is also discussed.

*State of Texas*

The State of Texas emphasized that the Legislature clearly stated that the compensation paid under Chapter 283 constitutes full compensation to a municipality for all of a CTP's facilities located within a public ROW, including interoffice transport and other transmission media that do not terminate at an end-use customer's premises, even though those types of lines are not used in the calculation of the compensation. The State of Texas agreed that access lines that pass through a municipality have been excluded from the Texas Local Government Code, Chapter 283 compensation regime. The State of Texas argued that the statutory provision expressly addresses those lines that do not terminate at a customer premise and the provision states that municipalities are being compensated even though the lines are not used in calculating the compensation. Therefore, the State of Texas concluded that there is simply no room for additional compensation to be required for "other" lines located in the public ROW under alternative ordinances or franchise agreements.

*Industry*

SWBT suggested that the imposition of a fee or contractual requirement before a telecommunications provider is permitted to use the public ROW could have the effect of prohibiting the provision of telecommunications service. SWBT argued that the only authority under the law for imposition of any type of fee is Chapter 283, and Chapter 283 places control over the establishment of that fee with the commission.

Verizon asserted that, consistent with their comments filed in Project Number 22909 on November 29, 2000, a CTP should not be required to compensate a city for the CTP's lines that pass through the city and do not terminate at an end-use customer in that particular city. Verizon stated that such compensation would conflict with HB 1777. Verizon acknowledged that even though a CTP may not have access lines within a city, any CTP excavating within a city's ROW is still subject to that city's police powers, as well as to that city's reasonable restoration standards.

AT&T argued that Texas Local Government Code, Chapter 283 prohibits municipalities from assessing additional fees and that exemption of payment for pass- through lines does not result in free use of public assets because cities are fully compensated for all public ROW usage in the aggregate, by the receipt of all access line fee revenues, as expressly provided in HB 1777. AT&T referenced the brief it submitted on November 29, 2000, which argued that its position is not statutory interpretation, but the Act's express language. Furthermore, AT&T maintained that assertions that the cities did not agree to this exemption in the legislative process have no legal relevance. AT&T summarized that HB 1777 established a comprehensive, statewide scheme for use of public ROWs by CTPs and for compensation to municipalities. AT&T stated that HB 1777 was designed to preserve existing levels of revenue and to speed entry into the market by new providers. Further, AT&T stated that the Legislature was clear in its statutory statement of policy and purpose and in the operative language finding that this compensation scheme is fair and reasonable and is deemed to be full compensation to a city for the use of the public ROW by a CTP. AT&T relied upon key provisions of HB 1777 to argue that the Legislature's stated purpose was to establish a uniform method of compensating municipalities that is administratively simple, competitively neutral and non-discriminatory, and provides fair and reasonable compensation. AT&T argued that wholesale facilities, network facilities that pass through a city, or other non-end-user facilities are not considered to be "access lines." AT&T contended that the access line fee under HB 1777 is the only fee a municipality is authorized to impose on a CTP for use of the ROW, and that any other fee is expressly prohibited.

AT&T maintained that: (1) CTPs in compliance with HB 1777 are not subject to municipal franchise requirements; (2) all public ROW usage is subject to §283.056, rather than just that particular ROW within the municipality in which service is being provided; (3) municipalities may require a construction permit under their police power but may not charge a CTP for the permit; and (4) payment by CTPs of access line fees is not limited to just the city in which service is provided but applies to all CTPs, all CTP facilities, all public ROWs, to all cities, and to all compensation, other than access fees.

AT&T argued that given the practical reality of network development, CTPs typically build several fiber optic rings which may span several cities when first entering a new market. AT&T contended that a CTP must first build its system in a metropolitan area before serving retail customers with that system, which may take years before lateral lines are built off the rings to specific municipalities; therefore, until a CTP begins serving end-use customers in a municipality in which its facilities are located, the CTP will not be paying the quarterly access fees to that municipality. AT&T asserted that when the CTP serves end-use customers in a municipality, the CTP will begin to pay quarterly access fees to that city. AT&T maintained that to pay both franchise fees and access line fees would result in duplicate compensation to a city for use of the ROW. AT&T argued that CTPs have an economic incentive to achieve full utilization of their facilities; thus, pass-through lines not serving end-users may be a temporary phenomenon.

AT&T contended that the commission's access line counting rule at §26.465 recognizes lines other than access lines and ensures cities are fully compensated. AT&T opined that it is immaterial whether a particular facility is counted as an access line because the total access lines within the city and the total fees are a "proxy" and a one-to- one correlation between lines and fees is not necessary to ensure a city receives adequate compensation. AT&T maintained that the commission already has recognized that non- access lines are not counted in determining the amount to be paid to cities as compensation for all of the usage of their ROWs.

AT&T argued that pass-through lines are covered by HB 1777, so long as the lines belong to a CTP. AT&T asserted that the definition of "access lines" excludes "interoffice transport and other transmission media that do not terminate at an end-use customer's premises," but that HB 1777 did not exclude non-access lines when it authorized CTPs to "erect poles or construct conduit, cable, switches, and related appurtenances and facilities and excavate within a public ROW to provide telecommunications service." AT&T cited §283.052(b) as stating that "all use" of a public right-of-way is subject to §283.056, and that a city can require a construction permit for a CTP "locating facilities in or on public rights-of-way within the city," which, again, are not limited to access lines, but that the city may not impose any cost on the CTP for such a permit. AT&T argued that §283.056(f) expressly states that CTP ROW usage for non end-user lines is considered to have been fully compensated by the city's receipt of access line revenues.

WorldCom expressed concern as to what is included in the term "other transmission media."

The CLEC Coalition supported approval of the proposed amendment to §26.465 because the amendment makes clear the Legislature's intent in Texas Local Government Code, Chapter 283 to develop a uniform access line based compensation scheme for use of the public ROWs by CTPs. CLEC Coalition argued that the Legislature did not intend for multiple assessments to be imposed on CTPs, and that additional fees may not be imposed on CTPs for lines that pass through a municipality. The CLEC Coalition pointed out that proposed amendments to §26.465 expressly incorporate the provisions of Texas Local Government Code, Chapter 283 that provide that compensation paid under Chapter 283 constitutes "full compensation" for all of a CTP's facilities located within the public ROW, and therefore the proposed amendments are proper implementation of Chapter 283. The CLEC Coalition supported its position with an additional argument that CTPs typically build fiber optic "rings" or "backbones" when entering a new market. The CLEC Coalition explained that CTPs have a strong economic incentive to achieve full utilization of their networks and to serve as many end- use customers as possible in each municipality served by the ring but that it takes varying amounts of time before a CTP can complete lateral lines. The CLEC Coalition argued that when the CTP builds a lateral line and begins serving end-use customers in a particular municipality, the CTP would begin paying access line fees to that municipality at that time.

The CLEC Coalition articulated four situations in which the determination of how to address pass-through lines is critical: (1) an ILEC, although it serves end-use customers in each city where it has facilities, has pass-through facilities connecting cities; (2) new CTPs that are deploying new networks in metropolitan areas before they have end-use customers in that municipality; (3) fiber-laying CTPs that started to deploy their networks prior to HB 1777 and entered into license agreements with cities, but are now acquiring end-use customers and want to pay under Chapter 283; (4) CTPs that were formerly Interexchange Carriers (IXCs) or Competitive Access Providers (CAPs) and now desire to integrate and use their networks to provide service to end-use customers within the municipalities.

The CLEC Coalition contended that pass-through lines are not subject to the imposition of additional municipal fees. The CLEC Coalition commented that there is no legal basis for additional fees to be imposed upon a CTP that passes through a municipality but does not yet serve end-use customers located there. The CLEC Coalition stated that the municipalities' arguments against proposed §26.465 are counter to §283.056(f), which expressly recognized the existence in the public ROWs of facilities that are not access lines. The CLEC Coalition argued that §283.056(f) is straightforward and unambiguous; nonetheless, the pass-through issue has plagued new CTPs currently constructing networks to serve end-use customers.

The CLEC Coalition argued that §283.051(a) prohibits imposition of any fee other than the access line fees established under §283.055 on a CTP that has installed facilities within a public ROW and that is providing telecommunications services within such municipality. The CLEC Coalition asserted that allowing municipalities to impose additional compensation on pass-through lines would render §283.056(f) ineffectual, would undermine the existence of this blanket authority, and would run contrary to the express language in §283.056(f) which recognizes that pass-through lines are not part of the basis for the calculation of compensation for usage of the ROW by CTPs.

*Municipalities*

TML argued that §283.056(f), the provision of HB 1777 cited in the proposed rule, is intended to apply to a CTP providing local exchange service in the city in which that CTP is using public ROWs. TML maintained that the entire focus of traditional city franchising practices and of HB 1777 was upon telecommunications companies that provided local service and §283.056(f) merely carries out that tradition. TML contended that when local service was provided, compensation for use of public ROWs was based upon the telecommunications revenues from local service, and subsection (f) merely identifies certain lines within the realm of local service that are not to be counted as access lines.

TML maintained that CTPs that do not provide local exchange service in a city do not pay access line charges on the lines that pass through the city and are not exempt from city licensing fees because they are not subject to HB 1777. TML argued that such CTPs are not authorized to use city ROWs for free and traditionally must pay a franchise fee or license fee usually based on linear-foot charges as rental for the occupancy and use of the ROWs. TML asserted that the proposed language contained in subsection (f)(5) correctly states how HB 1777 should be interpreted. TML argued that "lines that pass through a city but do not terminate at an end-use customer's premises should not be counted as access lines. Instead, those lines are outside the purview of HB 1777, and the city is entitled and required to make linear foot compensation or similar requirements for the placement of such lines."

Houston agreed that access lines should be counted in, and attributed to, the municipality in which the end-use customer is located. However, it contended that HB 1777 was never intended to address the issue of pass-through line compensation because the scope of the bill was limited to establishing a uniform method of compensation by CTPs for municipal ROW based on access lines.

TCCFUI asserted that license agreements for ROW use by companies not providing service to customers within a city existed prior to HB 1777 and that there were no instructions from commission staff to include such fees in the base amount. TCCFUI stated that the companies' filings affirmed that the lines at issue are not access lines, are not used to provide local exchange service, and are therefore outside the scope of HB 1777. TCCFUI asserted that the companies are mistaken in arguing that there should be a subsidy for such lines by allowing free ROW use for such lines.

Plano argued that, based on the references in Texas Local Government Code §283.002(1) to providing services to end-use customers within "the" (and not "a") municipality, pass-through lines clearly do not fall within the definition of "access line" under Chapter 283 of the Texas Local Government Code. Plano asserted that if pass- through lines fail to meet the very definition of "access lines" established by HB 1777, then it would require an unfathomable stretch of the imagination to suggest, first of all, that those lines even fall within the purview of HB 1777 and, secondly, that the compensation a municipality receives from CTPs with lines that meet the definition of "access line" would constitute "full compensation to a municipality for all of a CTP's facilities located within a public right-of-way."

Plano stated that in a recent letter opinion issued in Project Number 23557, *Forum to Address Municipal and Provider Complaints*, commission staff rejected an argument made by MCImetro that, "as a certificated telecommunications provider (CTP), the access line charges it pays to municipalities should constitute full compensation." Plano further contended that commission staff also rejected MCImetro's argument that compensation it pays under Chapter 283 constitutes the only amount to which cities are entitled, regardless of whether the access lines in question fall within HB 1777. Plano argued that although the lines at issue in that case were interexchange lines, these same arguments have been made repeatedly by CTPs with regard to all lines. Plano explained that CTPs have asserted that, because they are CTPs and because they pay compensation to a municipality somewhere in the State of Texas, they are exempted from compensating the municipality through which they pass without providing local exchange telephone service under Chapter 283. Plano contended that the commission has determined that some lines (i.e., interexchange, cable, and wireless) do not fall under Chapter 283 because they do not meet the definition of "access lines," and that the commission has further acknowledged that, for those lines, compensation continues outside the framework of HB 1777. Plano asserted that pass-through lines do not meet the definition of "access lines" under Chapter 283 and thus are subject to compensation outside the framework of HB 1777.

Plano argued that based on the assumption that HB 1777 was intended to be revenue neutral, cities were instructed by the commission to calculate their base amounts using franchise revenues received from telecommunications companies in calendar year 1998. Plano asserted that a city's base amount did not include license revenues because cities were told that the lines for which licenses were being obtained did not meet the definition of "access lines" and therefore were not to be included in the base amount. Plano contended that cities understood that the access lines related to the franchise fees used to calculate the base amount would be divided into the base amount either through a ratio or percentage in order to determine how the burden of the base amount would be allocated across the three categories of access lines. Plano maintained that compensation from pass-through lines was not included in cities' base amounts under Chapter 283 specifically because such lines did not meet the definition of "access lines" under Chapter 283. Plano argued that if the commission adopts the proposed amendment to §26.465, the commission would have included access lines without having included the compensation related to those access lines, and that, as a result, cities' revenues will be reduced, and the goal of revenue neutrality would be destroyed.

Plano contended that from the language of the commission Order adopting §26.463 at its October 21, 1999 Open Meeting, it is clear that the commission did not intend to include compensation in the base amount from providers whose access lines would be excluded from the provisions of HB 1777 because such lines did not meet the definition of "access line." Plano maintained that the commission specifically excluded lines belonging to IXCs, cable providers and wireless providers because they did not meet the statutory definition of "access lines" under HB 1777. Plano argued that, as a result, the commission intentionally did not include compensation received by municipalities from those lines because, by including such compensation but excluding the access lines, "the burden of compensating the municipality for use of the ROWs would be shouldered inequitably by ILECs and CLECs." Plano asserted that if the commission now adopts the proposed amendment (which would establish that pass- through lines qualify as "access lines" under Chapter 283) but not include the compensation that cities received for those lines pursuant to alternative compensation mechanisms, a result similar to what would have happened in the IXC, cable and wireless provider scenario would ensue.

Irving commented that its understanding regarding pass-through lines was that the pass-through lines that were in existence in 1998 and prior were not to be counted in the base amount calculation. Irving stated that this was the instruction of the commission staff at that time, as Irving understood it.

*Commission Response*

The commission's position is that pass-through lines, lines that pass through one municipality to reach an end-user in another municipality, allow the delivery of local exchange service. Therefore, municipalities receive full compensation for pass-through lines in the municipal fee, because pass-through lines are "access lines," as defined in Texas Local Government Code §283.002(1). The commission notes that this rule amendment does not address all items under HB 1777. The commission intends to address additional pass-through issues in a subsequent rulemaking. As set out in §283.002(1), an access line may be a "switched transmission path . . . that allows the delivery of local exchange telephone services," a "termination point or points of a nonswitched telephone or other circuit," or a "switched transmission path . . . used to provide central office-based PBX-type services." As articulated by the State of Texas, and clearly set out in §283.056(f), there is simply no room in the language of the statute to allow additional compensation to be required for "other" access lines located in the public ROW under ordinances or franchise agreements that are disallowed under HB 1777. Such an artificially complicated process undermines the intent of creating a non- discriminatory, competitively neutral, uniform method for compensating municipalities for the use of the ROW that is administratively simple for municipalities and telecommunications providers. Moreover, subjecting access lines that pass through a municipality to the historic franchise/ordinance process discontinued by HB 1777 contradicts the clear language of the law.

The theory that an access line can be broken down into its component parts according to municipal boundaries and then subjected to multiple access line fees was explicitly disallowed by the Legislature. HB 1777 took into consideration the interconnected nature of the complex telecommunications infrastructure serving the rural and urban cities of Texas. Because an access line may reach an end-use customer after being transported from a synchronous optical network (SONET) ring in another city, or an access line serving the end-use customer may require transport between two or more central offices, or any number of other alternative transport combinations, HB 1777 addressed the treatment of this transport portion of the access line. For example, as set out in §283.002(1)(B), an access line "may not be construed to include interoffice transport or other transmission media that do not terminate at an end-use customer's premises or to permit duplicate or multiple assessment of access line rates on the provision of a single service." Because an access line may utilize numerous types of transmission media, the designation of interoffice transport or other transmission media as a separate access line, subject to an additional access line fee, would subject some end- use customers to duplicate or multiple assessment of access line rates. This discriminatory result was both anticipated by the Legislature and expressly prohibited.

The persistent theory that pass-through lines are not access lines because the CTP does not deliver local exchange within the specific municipality is contrary to the express language of the statute. The statutory definition of "access line" is the determining factor in the classification of such pass-through lines. The access line definition in §283.002(1)(A) has three subparts, (i), (ii), and (iii). In (i), an access line is "each switched transmission path . . . extended to the end-use customer's premises within *the* municipality, that allows the delivery of local exchange telephone services within *a* municipality . . . ." Under (ii), an access line is also "each termination point or points . . . identified by and provided to, the end-use customer for delivery of nonswitched telecommunications services within *the* municipality." Section (iii) describes the third type of access line as "each switched transmission path . . . used to provide central office-based PBX-type services...within *the* municipality." Municipalities rely upon the use of the article "the" as emphasized in the foregoing sections, for the proposition that an access line is only an access line insofar as it serves that specific city; an access line crossing municipal boundaries to serve an end-user in a neighboring municipality would, therefore, fall out of the category of access line and out of the HB 1777 framework altogether, thereby allowing a municipality to impose any compensation methodology upon this "new" category of line it may choose. However, the commission would note that subpart (i) also defines an access line in terms of allowing "the delivery of local exchange telephone service within *a* municipality." The mere use of the article "the" cannot be determinative of this issue in light of the very specific wording throughout HB 1777. While it is true that the statute explicitly exempts interoffice transport or other transmission media that do not terminate at an end-use customer's premises from the definition of access line, it does so to prevent the inappropriate result of duplicate or multiple assessment of fees. Under §283.002(1)(B), an access line may not be construed to include interoffice transport or other transmission media that do not terminate at an end-use customer's premises or to permit duplicate or multiple assessment of access line rates on the provision of a single service. To count and assess compensation separately on every piece of the complicated network infrastructure that eventually terminates at an end-use customer's premises, would invariably result in assessing duplicate or even multiple access line rates on that end-use customer. Furthermore, §283.056(f) expressly states that "the compensation paid under this chapter constitutes full compensation to a municipality for *all* of a certificated telecommunications providers' facilities located within a public right-of-way, including interoffice transport and other transmission media that do not terminate at an end-use customer's premises, even though those types of lines are not used in the calculation of the compensation." Accordingly, the commission does not consider the choice of the article "the" to limit an "access line" to be within HB 1777 only when that line serves a designated customer within the boundary of any single municipality.

The commission also specifically agrees with the concept that the fee-per-access line compensation methodology established under HB 1777 and the total fees paid to a municipality thereunder are a proxy for the compensation formerly received by the municipality under the franchise regime in place prior to the enactment of HB 1777. Many cities were paid on a flat-fee basis or a percentage of gross receipts basis. Even where some municipalities had changed to a fee-per-access line compensation basis, an access line was not necessarily defined the same way as it is defined in HB 1777. But because a municipality's total 1998 franchise revenues from multiple sources, such as fees or in-kind services, were consolidated into one pot and then redistributed over access lines under the HB 1777 compensation methodology, a one-to-one correlation between access lines and municipal fees is unnecessary to ensure that a city receives adequate and appropriate compensation for use of the public ROW by CTPs. This is not "free use" of the ROW, but instead usage fully compensated under the HB 1777 regime.

The commission appreciates WorldCom's expressed concern as to what is included in the term "other transmission media." The commission relies upon the Legislature's express language used under Texas Local Government Code §283.056(f). To the extent that the phrase refers to lines used to deliver local exchange service, the commission understands this language to mean any telecommunications transmission line that does not terminate at an end-use customer's premises for the provision of local exchange service.

The commission disagrees with the position that compensation based on telecommunications revenues from the local service should be determinative of the calculation. While acknowledging that prior to HB 1777 some cities' franchise agreements were based upon revenue values, the commission points out that HB 1777 changed the compensation regime and made it uniform statewide. The commission relies on the four-corners of the statute to conclude that the Legislature has determined that, going forward, the municipal compensation for use of the public ROWs is to be recovered from the end-users of access lines.

The commission disagrees with the assertion that it provided improper instructions to the municipalities regarding the methodology of the 1998 municipal base amount calculation. The commission presented all municipalities with the same accurate documentation and information. The commission provided the following to ensure correct calculation of base amount by all municipalities: (1) numerous well-attended workshops held across the state in conjunction with TML throughout 1999; (2) individual calls and conference calls conducted by commission staff; and (3) mail-outs to every municipality in the state that included directions to the website for the "INSTRUCTION PACKET FOR FORM FOR CALCULATING RIGHTS-OF-WAY COMPENSATION AND PROGRAM FOR CALCULATING RIGHTS-OF-WAY COMPENSATION." The forms themselves were also located on this website, as well as contact information on a commission representative assigned to answer questions.

Contrary to Plano's assertion that the commission's decisions regarding long-distance lines are inconsistent with this proposed amendment, the commission has been entirely consistent in addressing these two separate issues that have been sufficiently distinguished based upon the legislative intent represented in HB 1777. The commission disagrees with Plano's argument that the adoption of the proposed amendment to §26.465 would contradict the approach espoused by the commission in the October 21, 1999 Order adopting §26.463. The commission further disagrees with Plano's argument that it is contradicting itself on the issue of pass-through lines. The lines discussed in the October 21, 1999 Order and in the opinion in Project Number 23557 are long-distance, long-haul lines that are clearly not designated for the delivery of local exchange service and are therefore governed by the long distance license agreement framework in municipalities. As explained in the foregoing sections, pass-through lines, on the other hand, are clearly used to allow the delivery of local exchange service and are therefore access lines included in the HB 1777 framework. While industry may be seeking to cloud this issue by designating long-distance lines as pass-through lines within the meaning of this proposed amendment, the commission maintains its stance that long- distance lines are not within the language or intent of HB 1777. Consistent with this understanding, the commission identified fees related to long-distance lines in municipal applications and discussed such items with each city individually to determine whether compensation from long-distance lines was being included in the base amount. To have included such compensation would not only be contrary to HB 1777, but would have resulted in the subsidization by local exchange customers of long-distance customers' franchise fee payments. The commission has not been inconsistent in this approach.

The commission disagrees with TML's assessment that the proposed amendment to §26.465(f)(5) may allow CTPs to avoid counting as access line those lines that pass through a city but do not terminate at an end-use customer's premises within that municipality. The provisions existing under §26.463(c) and (d) maintain that the franchise revenue for these lines was included in the municipal base amount under the HB 1777 framework. Further, Texas Local Government Code §283.055(j) and §283.056(f) and the existing language in §26.465(d)(1)(C) specifically provide that if a transmission path crosses more than one municipality, CTPs must count the line only in the municipality where the end-use customer is located. Clearly, pass-through lines that deliver local exchange service are within the HB 1777 framework, as they were included in the 1998 base amount, but are not to be actively counted by CTPs in each crossed municipality in a quarterly access line count report. This concept is already included in existing §26.465(f)(1). Because the proposed amendment to §26.465(f) may confuse the issue inadvertently, the commission strikes the proposed amendment to proposed §26.465(f).

The commission makes no change to §26.465(d) and adopts the subsection as proposed.

*Historical ROW Compensation Issues*

Parties submitted comments regarding the historical background on ownership and management of the public ROW.

*Industry*

SWBT asserted that a municipality's power lies in its ability to supervise the use of the right-of-way, including the authority to assess and collect reasonable fees for the cost of that supervision. SWBT also suggested that this power of supervision now rests with the commission, pursuant to Texas Local Government Code, Chapter 283. SWBT emphasized that the Texas Legislature determined that ROW fees based on access lines provide the best method of compensation to municipalities from CTPs. On that basis, the commission set the amount of those fees. SWBT concluded that municipalities are not entitled to extract compensation beyond that expressly set forth in Chapter 283 and established by the commission.

SWBT emphasized that municipalities do not own public ROWs, including those located within municipal borders. SWBT reflected upon the history of municipalities' responsibility to manage the public ROW and noted that while municipalities have been authorized to manage the public ROW and are authorized to recover reasonable administrative costs of performing that managerial function, the municipalities are not authorized to "rent" the State's property, including the public ROW. SWBT suggested that the cities are now collecting fees in excess of administrative costs, and SWBT questioned the lawfulness of those fees. SWBT argued that the law has not changed to authorize municipalities to enhance collections further. Upon this basis, SWBT also disputed the municipalities' argument that the municipalities are giving away a valuable public interest "for free." SWBT concluded that if the municipality lacks power as a sovereign to exclude CTPs from public ROWs, then the municipality does not have authority to impose fees and other restrictions that would flow from that power. SWBT stated that municipalities have never had the right to exact tribute for a transiting CTP's use of the right of way and, thus, are not forced to give anything away under Chapter 283 or under the commission's rules.

At the public hearing, SWBT clarified its position, explaining that it is not challenging whether cities can receive compensation, but rather is questioning if cities can require compensation under the circumstances described in the proposed rule. SWBT characterized the cities' position as requiring the collection of a fee whenever public property is put to private or commercial use of any kind. SWBT maintained that ROWs are not city property but rather State property.

*Municipalities*

During the public hearing, the Coalition of Cities rebutted SWBT's comments by providing examples, providing a historical summary, and referencing Texas case law in support of its position that cities have authority to receive value-based compensation, control their ROWs, and promulgate police power. The Coalition of Cities conceded that its comments might not be appropriate in the context of the public hearing because they relate to matters previously reviewed in the context of the HB 1777 legislation. Likewise, the Coalition of Cities commented that this is not the forum to make decisions regarding the legitimacy of cities' receipt of value-based fees because the Legislature made these decisions regarding appropriate compensation.

*Commission Response*

Consistent with the express language of the statute in Texas Local Government Code §283.056(c), a municipality may exercise police power-based regulations in the management of the activities of CTPs within a public ROW, but only to the extent that such regulations are reasonably necessary to protect the health, safety, and welfare of the public. Although SWBT and the Coalition of Cities provided extensive and detailed discussions regarding the ownership of the public ROWs, the arguments of SWBT and the Coalition of Cities are outside the scope of this rulemaking. The question of ownership of the public ROWs is not at issue; to the extent that ownership was ever in question, the Legislature, in authorizing municipalities to retain the power to exercise police power-based regulations and to receive compensation for use of the ROWs, appears to have addressed this question in 1999. HB 1777 provides the legislative directive regarding compensation and use of the ROW. This rulemaking specifically contemplates and implements that legislative directive. Issues regarding the legitimacy of the Legislature's decision and the legality of ROW ownership are outside the scope of this rulemaking and, therefore, are more appropriately addressed in a different forum.

*Legislative Intent of HB 1777*

Parties submitted comments regarding the consistency of the proposed amendment with the policies and purposes of HB 1777.

*Municipalities*

Plano asserted that the proposed amendment to §26.465 fails to consider the provisions found throughout Texas Local Government Code, Chapter 283 and violates the purpose and intent of HB 1777. Plano argued that Texas Local Government Code §283.001 clearly states that the policy of the State of Texas is to remove the barriers to entry for CTPs, to increase competition, and to ensure that municipalities receive fair and reasonable compensation for the use of public ROWs within the municipality. Plano contended that because Chapter 283 contains other references to CTPs that provide telecommunications services *within* the municipality, the compensation scheme created under HB 1777 was intended to apply to CTPs providing local exchange telephone service within the particular municipality in which the access lines are located and not merely within a municipality in the State of Texas. Plano argued that cities are entitled to receive compensation from pass-through CTPs through mechanisms other than the access line fees established by Texas Local Government Code, Chapter 283.

TCCFUI contended that the preamble of HB 1777, Texas Local Government Code §283.001, sets out the policy of the state and the purpose of the bill. TCCFUI reiterated that the policies of the state are to encourage competition, reduce barriers, ensure no competitive advantage between providers and reduce uncertainty, while ensuring that municipalities retain authority to manage the public ROWs and receive compensation for the use of public ROWs.

TCCFUI listed the six purposes of the law and argued that the proposed amendment to §26.465 violates each and every purpose of that law. First, TCCFUI maintained that the proposed amendment to §26.465 would fail to meet the objective of being administratively simple for municipalities and telecommunications providers because it would allow any company to claim it falls under the exception provided by the proposed amendment to §26.465, and that each city would have to do investigative work to find out whether the company's claims are true within that city, thus becoming more complex than the current situation, with the new complexity alone defeating the purpose of HB 1777. Next, TCCFUI argued that the amendment would not be consistent with HB 1777 by virtue of allowing free use of public ROW. Moreover, TCCFUI asserted that allowing a few affected telecommunications companies free use of the ROW in selected cities would be far from competitively neutral or non-discriminatory. TCCFUI characterized the amendment as creating a situation inconsistent with the burdens placed upon a municipality, by allowing the very company that is causing a problem to not pay for the burdens that it has created. The proposed amendment would also not provide for any compensation for use of the ROWs within the communities burdened by companies not offering services within a city, such that these communities are burdened by those companies' facilities in the ROW and their citizens receive no benefit from those facilities, while the companies receive a benefit from free use of the public ROWs. Finally TCCFUI contended that the amendment would not provide for fair and reasonable compensation for the use of public ROWs, because increasing the number of lines to be counted and divided into the base amount would have the effect of diluting the base amount, and diluting municipalities' revenues, and because revenues previously received from "pass-through" companies, not considered as CTPs because they did not provide service within the municipality, were not included in the cities' base amount.

TCCFUI maintained that HB 1777 is replete with references to payment for the use of the ROW by companies that use the ROW. TCCFUI asserted that HB 1777 clearly applies only to companies providing services within a municipality; otherwise the company falls outside of its provisions, citing Texas Local Government Code §283.051. TCCFUI argued that it strains the English language and is not the every day or common sense reading of that phrase to say that §283.051 means that a company paying any city can escape its obligations to every other city whose ROW is used.

TCCFUI contended that the title of Texas Local Government Code §283.052, "Effect of Payment of Right-of-Way Fees to Municipality," is premised upon paying fees to the municipality whose ROWs a company wishes to use, and that there is no room for an interpretation that allows a company to not pay fees to a city whose ROWs are being used.

TML stated that Texas Local Government Code §283.001 sets out the policy and purpose of the bill, which is clearly that cities are to be compensated reasonably for use of ROWs. TML referenced §§283.002, 283.051(a), 283.054(c), 283.055(b), and 283.056(a)(1) to assert that there is a demonstrable clear intent on the part of the Legislature to limit the application of HB 1777 to CTPs that are providing local exchange service within the cities in which the CTPs are using and occupying ROWs. TML explained that the statutory provisions demonstrating the overall intent of HB 1777 cannot be ignored and that to do so jeopardizes the stability that HB 1777 was intended to provide and which, until this rule was proposed, was being accomplished.

TML asserted that §283.056 should not be confused with CTPs who do not provide local exchange service. TML argued that "section 283.056(a)(1) clearly states that a city may not require a CTP to pay compensation, other than the access line fees authorized by §283.055, *for the right to use a public right-of-way to provide telecommunications services in the municipality* and may not require a CTP to provide any services or facilities *for the right to use a public right-of-way or to provide telecommunications services in the municipality*" (emphasis in original). TML further opined that every subsection and provision of §283.056 addresses either a city's right of or prohibition against regulation and collection of compensation with regard to a CTP providing local exchange service in the city, and that to pluck subsection (f)from §283.056 and base the proposed rule upon it is to take it out of context in violation of well-established rules of statutory construction. TML declared that when construing the intent of a law, the courts do not consider parts of the law in isolation without considering the rest of the statute and that this is so even when the court is not seeking to determine legislative intent. TML further argued that, assuming that §283.056(f) creates ambiguity, then it is not proper for the commission to simply ignore the rest of the statute in order to give effect to one interpretation of that subsection and that it is imperative that the entirety of HB 1777 be examined in order to determine the correct meaning of §283.056(f) within the context of the entire statute. TML opined that upon doing so, it becomes evident that the proposed amendment to §26.465 ignores the true purpose behind HB 1777.

The Coalition of Cities contended that the language in Texas Local Government Code Chapter 283 does not apply to a CTP that is not providing telecommunications services within a municipality, and that, otherwise, if the CTP has one end-user customer in one small city in rural Texas, the CTP can pass through the other approximately 1,000 cities in Texas without any compensation. The Coalition of Cities argued that to construe HB 1777 in this manner is not a proper reading of its words or of its intent as it was adopted by the Texas Legislature in 1999.

The Coalition of Cities argued that it is contrary to statutory construction to ignore the clear statutory language. The Coalition of Cities contended that Government Code §311.021 provides that in construing a statute, "the entire statute is to be effective" and that the "public interest is favored over private interest." The Coalition of Cities asserted that CTPs that do not provide telecommunications services in the city are outside the purview of HB 1777 in those cities and the commission has no authority to address the type of compensation those "pass-through" providers pay to cities for use of the ROWs. The Coalition of Cities maintained that typically the kind of compensation those providers have paid in the past has been a linear-foot charge.

Garland asserted that the proposed revisions to §26.465 run counter to the legislative intent of HB 1777. Garland argued that pass-through lines are outside the parameters of HB 1777, and therefore owners of such lines must compensate the municipality for use of the ROWs in a manner determined by the municipality, usually on a linear-foot basis. Garland stated that it is clear from §283.001(a)(4) and §283.052(a) that the access line fees and the statutory authorization for use of ROWs replace fees and franchises themselves. Garland argued that the new access line fees, which replace franchise fees, are only part of the fair and reasonable compensation due to the municipalities for use of public ROWs by CTPs. Garland argued that HB 1777 did not replace non-franchise agreements or municipal licenses required for the use of ROWs by companies that do not transact business within the city. Garland stated that historically, such companies were required to obtain agreements or licenses to traverse the city, and the municipality charged a fee for use of the ROWs, usually on a linear-foot basis. Garland added that such companies were also subject to ROW ordinances. Garland argued the need for the separate treatment of owners of these pass-through lines continues today. Garland argued that if any CTP is allowed to use public ROWs without the payment of fair and reasonable compensation, then the policy of the state, as expressed in §283.001, has been subverted. Garland argued that Chapter 283 does not preempt municipal fee requirements for providers, certificated or non-certificated, who are not providing telecommunications services within the city. Garland stated that free use of the ROW by anyone is not contemplated by HB 1777, and is not permitted by the Texas Constitution.

*Industry*

AT&T argued that cities' claims that they did not agree to a non-access line exemption is irrelevant. AT&T maintained that statements made by an individual legislator after the enactment of a statute may not determine legislative intent. AT&T asserted that the same concept applies to an interested party, and statements as to what was intended or to what was "agreed" cannot be given legal relevance. AT&T maintained that if the statute is clear and unambiguous, extrinsic aids and rules of construction are inappropriate and the statute is to be given its plain and common meaning. AT&T asserted that HB 1777 expressly defines "access lines" as involving end-user terminations and expressly excludes interoffice transport and other non-end-user lines from the definition of access lines, and therefore, non-access lines are excluded from the requirements in §283.051 and §283.055 that fees be paid on the number of access lines a CTP has in a municipality.

AT&T argued that, even if the rules of statutory construction were applied, the same conclusion would result, as application of the Code Construction Act confirms that so long as the service provider is a CTP, the ROW usage is governed by HB 1777 and a city cannot require more.

AT&T opined that construing HB 1777 so as to impose extra compensation requirements on CTP pass-through lines, as the cities' construction of HB 1777 entails, would have several consequences. It would: (1) render Texas Local Government Code §283.052(a) and §283.056(f) ineffectual; (2) not produce a just and reasonable result; (3) be unreasonable in light of the stated purpose of the statute; (4) not favor the public interest; (5) increase the end-use customer's bill; and (6) decrease the availability of competition.

AT&T argued that limiting cities to fee compensation for all CTP users of ROW, including pass-through lines, is consistent with the Code Construction Act. AT&T contended that the Code Construction Act provides that, in construing a statute, whether it is considered ambiguous on its face, a court may consider among other matters the: (1) object to be attained; (2) circumstances under which the statute was enacted; (3) legislative history; (4) common law or former statutory provisions, including laws on the same or similar subjects; (5) consequences of a particular construction; (6) administrative construction of the statute; and (7) title (caption), preamble, and emergency provision. AT&T maintained that when applied to HB 1777, each of these statutory construction aids further indicates that cities' position is without merit (*see* Texas Government Code Chapter 311, Code Construction Act).

The CLEC Coalition disagreed with the cities' position that proposed §26.465 violates the stated policies of the Texas Legislature and the express purpose of Chapter 283. Instead, the CLEC Coalition believed that the proposed amendment merely restates and clarifies the law as stated in §283.056(f) and is therefore entirely consistent with the policies and purposes of Chapter 283. The CLEC Coalition relied upon the six policies enumerated by the Legislature at the time Chapter 283 was enacted and argued that the proposed amendment does implement such policies. The CLEC Coalition argued that the proposed amendment: (1) properly implements §283.056(f), encourages competition in the provision of telecommunications services, and makes clear that pass- through lines are not subject to additional municipal fees; (2) reduces barriers to competition because payment of fees to municipalities before a CTP begins service to end-use customers is a significant economic barrier to entry; (3) ensures that providers of telecommunications services do not obtain a competitive advantage or disadvantage in their ability to obtain use of the public ROWs because a competitive advantage is not provided to one CTP over another with respect to ability to obtain use of the public ROWs; (4) fairly reduces the uncertainty and litigation concerning franchise fees because the clarity provided by the proposed amendment reduces uncertainty and obviates the need for city-by-city litigation of this issue in disparate forums; (5) retains municipal authority to manage public ROWs within the municipality to ensure the health, safety and welfare of the public because the proposed amendment does not disturb a municipality's authority to exercise its police power-based regulations and whether a CTP is installing pass-through facilities or installing service laterals, the CTP is subject to the police power-based regulatory authority of the municipality; and finally, (6) enables municipalities to receive from CTPs fair and reasonable compensation for the use of public ROWs within the municipality because Chapter 283 provides that municipalities receive access line fees and nothing more from CTPs. Access line fees, in the aggregate, provide fair and reasonable compensation to a municipality for use of the public ROWs by all CTPs, and the proposed amendment clarifies these compensation limitations and gives full effect to Chapter 283. The CLEC Coalition believed that the proposed amendment assures that municipalities do not exceed the statutory cap that has been placed on the level of compensation that may be collected by them.

The CLEC Coalition also articulated the six purposes of Chapter 283 that were identified by the Legislature and argued that the proposed amendment to §26.465 fulfills, rather than violates, each of those stated purposes. The CLEC Coalition commented that the proposed amendment is: (1) administratively simple for municipalities and telecommunications providers because it makes clear that CTPs are subject to one uniform fee based on the number of access lines within a municipality whereas imposition of additional fees on pass-through lines would be duplicitous and not administratively simple; (2) consistent with state and federal law because the proposed amendment restates the law in §283.056(f); (3) competitively neutral; (4) non- discriminatory because it clarifies that all CTPs pay ROW compensation on an access line basis, assures that the ROW compensation scheme is applied to CTPs on a competitively neutral and nondiscriminatory basis, and fulfills the expressly created single uniform method for ROW compensation that is to be applied in a competitively neutral and nondiscriminatory manner, thereby complying with legislative intent by preventing multiple compensation schemes to be imposed on CTPs; and (5) consistent with the Legislature's determination that ROW fees based on access lines provide fair and reasonable compensation to municipalities; therefore, under Chapter 283, municipalities are not entitled to impose fees in addition to the access line fees.

*Commission Response*

The commission disagrees with the arguments that the amendment to §26.465 is contrary to the letter and intent of HB 1777. Both Chapter 283 and §26.465(d) are unambiguous. The commission virtually restated the statutory language into this proposed amendment, thus clearly capturing the intent of the statutory provisions. The commission fully considered each of the policies and purposes of this statute, as stated in Texas Local Government Code §283.001. The rule amendments are an accurate reflection of the statute and follow the intent as articulated within the four-corners of the statute. The arguments that the commission's interpretation of the statute is contrary to the legislative intent of the bill are unsupported by any documentation or secondary authority, such as material legislative history. Accordingly, the argument by the cities that the statute does not reflect their intentions is not an effective argument against the unambiguous language of the statute as constructed by the Legislature. In the absence of documentation, these arguments regarding their intentions are simply not legally relevant. The commission agrees with the CLEC Coalition's detailed analysis of the reasons that the proposed amendment to §26.465 meets the intent of HB 1777. The commission disagrees with the concept that HB 1777 did not contemplate pass-through lines, as §283.056(f) clearly refers to pass-through lines.

The commission again emphasizes that the lines subject to this proposed amendment are access lines that pass through a particular municipality to provide service elsewhere. Pursuant to the definition of access line, an access line may be either a switched transmission path or a non-switched transmission path. Long-distance lines are not within HB 1777 and, as has been stated by this commission since adoption of its initial rules in 1999, long-distance lines are not access lines and, therefore, continue under the existing per linear-foot or other compensation arrangements currently in place.

The compensation framework of HB 1777 is based upon the payment of monthly fees by end-users. The bill explicitly acknowledged in §283.056(f) that, to reach an end- user, an access line might take on the nature of interoffice transport and may require the use of other transmission media that do not terminate at that end-use customer's premises. However, under §283.002(1)(B), an access line may not be construed to include interoffice transport or other transmission media that do not terminate at an end-use customer's premises or to permit duplicate or multiple assessment of access line rates on the provision of a single service. To count and assess compensation separately on every piece part of the complicated network infrastructure that eventually terminates at an end- use customer's premises, would invariably result in assessing duplicate or even multiple access line rates on that end-use customer. In fact, the greater distance a customer is from the central office, the larger the fee. The impact such an approach would have upon rural customers would effectively render telephone service out of reach. Such an approach would not only run contrary to Texas' long-standing support for universal deployment of telephone service but would completely circumvent the words, the intent, and the spirit of HB 1777. Accordingly, the commission makes no modification to §26.465(d) in response to these comments and adopts provision, as proposed.

*Challenges to Constitutionality*

Parties submitted comments regarding the consistency of the amendment with the Texas Constitutional provisions which prohibit gifts of public property to private corporations.

*Municipalities*

Garland reiterated the initial comments of these parties that the proposed revisions to Rule §26.465 have no basis in the law, are contrary to the letter and intent of HB 1777, and are, in fact, unconstitutional. Garland asserted that the proposed revisions to §26.465 violate the Texas Constitution. Garland asserted that the language of HB 1777, as codified in Chapter 283 is unambiguous on the point that ROWs are valuable assets of municipalities, and that their use may not be granted without charge. Garland argued that ROWs are subject to the constitutional requirement that municipalities may not grant or loan any thing of value to a private person.

TML argued that "If adopted, this amendment will authorize telecommunications companies to lay lines and construct other facilities within city ROWs without compensating the city in which the facilities are placed, provided that the company placing such facilities does not provide local exchange service in that city." TML contended that such a result is the exact opposite of the express policy and purpose of HB 1777, threatens the constitutionality of HB 1777, and simply defies logic. TML asserted that "to construe §283.056(f) to require CTPs to use ROW for free will make HB 1777 unconstitutional by being violative of Article 3, Section 52 and Article XI, Section 3 of the Texas Constitution."

The Coalition of Cities argued that a CTP who passes through a city but who does not have any end-use customers in the city, not only may be charged ROW rental fees other than access line fees, but also should be charged such fees to be consistent with Texas constitutional requirements. The Coalition of Cities stated that it concurs with prior comments filed by TML that if rental fees are not recovered for use of the public ROWs, it violates the Texas constitutional provisions that a city is prohibited from giving public property to private parties without adequate compensation. The coalition of cities cited Texas Constitution, Art. III, §52 and Art. XI, §3 to support their position that both provisions prohibit gifts of public property to private corporations.

TCCFUI stated that adoption of the amendment to §26.465 requires granting free use of the ROW and sows the seeds for a finding of unconstitutionality of HB 1777. TCCFUI argued that a particular consequence of the proposed amendment to §26.465 would be use of the public ROW in every city in Texas for one access line located in just one city in Texas. TCCFUI maintained that allowing the free use of public ROW within any city is both unconstitutional and inconsistent with HB 1777, as the Texas Constitution forbids giving away public property for private purposes. TCCFUI averred that those constitutional provisions are designed to forbid the kind of public subsidies, in the form of free use of the public ROW, contemplated by the proposed amendment, and that violation of the Texas Constitution is inconsistent with HB 1777.

Plano asserted that Texas Constitution, Article III, §52 prohibits, in part, gifts of public property to private corporations without adequate compensation. Plano maintained and agreed with the comments made by TCCFUI that the failure to recover use fees from pass-through CTPs constitutes a violation of that section.

*Industry*

AT&T asserted that the claim by municipalities that they are not being compensated for pass-through lines, which is invalid under Texas Constitution, Article III, §52 as a "free use" of public assets, is both factually and legally inaccurate, as cities are compensated, by the total amount of CTP end-user access line quarterly fees, for *all* uses of the public ROWs made both by end-user lines and by non-end-user lines. AT&T argued that HB 1777 does not provide that each specific ROW usage must have a specific amount of revenue associated with it, but instead provides a means of calculating an aggregate amount of revenue designed to keep the cities whole on what they were receiving before the advent of local competition.

AT&T contended that the literal text of the Texas Constitution, Article III, §52(a), by its terms is not applicable to this situation, as it provides in relevant part that, "the Legislature shall have no power to authorize any county, city, town or other political corporation or subdivision of the State to lend its credit or to grant public money or thing of value in aid of, or to any individual, association or corporation whatsoever." AT&T maintained that the article does not generally prohibit "free use" of public assets, but instead prohibits the Legislature from giving to cities or other political subdivisions the power to lend credit or grant money or things of value to private entities. AT&T further asserted that HB 1777 does not authorize a city to lend credit or grant money or things of value to private entities, but that the Legislature expressly granted to CTPs the right to use public ROWs, including for non-end-user lines, and legal title to a municipality's streets technically belongs to the State. AT&T argued that the city controls the streets only as trustee for the public, and a city does not have any authority to grant, and is not granting, a CTP the right to use the ROW when the city grants a construction permit for a pass-through line -- because the Legislature has already made that grant. Instead, all the city is doing when issuing a construction permit is exercising part of the police power narrowly preserved by HB 1777. AT&T stated that, given the public interest in telecommunications service, the Legislature was authorized under the Texas Constitution to prohibit a city from imposing ROW fees on CTPs' pass-through lines.

*Commission Response*

The commission believes that it is not necessary to debate or determine the constitutionality of duly enacted laws. The rule is an accurate restatement of the statute as enacted by the Legislature. The commission's charter is to craft a rule that clearly and accurately implements the law as written. To the extent that parties believe the law, and therefore the rule, are unconstitutional, any potential remedy would have to be pursued elsewhere.

The commission disagrees that the rule provides for municipalities' grant or loan of an asset with value to a private person. AT&T

accurately points out that HB 1777 is not premised upon compensation for each piece part of the network. In fact, HB 1777 expressly excluded certain types of facilities from compensation, including interoffice transport and other transmission media within the public ROWs that do not terminate at an end-use customer's premises, *even though those types of lines are not used in the calculation of the compensation*. However, these lines are not operating free of charge within the public ROWs. The termination point of the access line, at the end-use customer's premises, is both the point that is counted and that is subject to compensation. The components of the network that interconnect to achieve that termination are compensated through the eventual end-use customer on an aggregated basis. Because historical municipal franchise compensation has been reallocated and is now recovered over a different group, the end-use customers, those customers constitute the recovery vehicle for all compensation. Therefore, no public ROW is being granted or loaned without charge. Rather, municipalities are compensated in accordance with the end-use customer framework as decided and developed by the Legislature.

Industry commenters have pointed out many times that a company seeks to maximize its revenues by utilizing each part of its network. A line that passes through a municipality today represents a company's future goal and commitment to seek customers at all points along the access line. Deploying infrastructure takes time, as does competitively seeking new customers. There is no business model that supports cities' fear that a single line will deliberately be built to cross every city in Texas to serve a single customer. In the current business climate, CTPs are seeking new efficiencies and economies of scale by increasing market share at every opportunity.

The commission makes no modification to §26.465(d) in response to these comments and adopts the amendment as proposed.

ARGUMENTS REGARDING LONG-HAUL ISSUES

*Termination and Compensation Regarding Long-Haul License Agreements*

Parties submitted comments regarding whether contracts or license agreements related to long-haul long distance lines are covered by the statute and whether, as such, §283.054 created a termination right as to contracts or license agreements for long-haul long distance lines. Parties' concerns are addressed regarding the status of existing and future contracts.

*Industry*

SWBT focused on the point that the proposed amendment does not attempt to abrogate existing licensing agreements or other contracts between municipalities and CTPs. SWBT stated that CTPs that transit through municipalities were under no legal obligation to enter into agreements to access the public ROW for the installation or operation of telecommunications facilities. If CTPs chose to enter into agreements, the amendments proposed by the commission should not affect those agreements. Thus, concluded SWBT, there is no basis for the municipalities' claim that the proposed amendment will have a negative revenue impact.

SWBT also addressed the municipalities' position that the proposed amendments would change the nature of the relationships between CTPs and municipalities. SWBT reiterated the municipalities' position that some CTPs have traditionally paid franchise fees or license fees based on formulas developed by the municipalities. SWBT argued that those payments reflected contractual agreements rather than legal obligations under state law and went on to argue that, notwithstanding the existence of contracts between municipalities and some transiting-only CTP, municipalities do not have the authority to compel telecommunications providers to enter into contracts or pay tribute for the privilege of using the public ROWs to provide telecommunications service. SWBT argued that the fact that some CTPs have entered into contracts in the past does not create the legal authority to require contracts in the future. SWBT requested the commission adopt the proposed amendment to §26.465.

AT&T opined that prior to HB 1777, Texas law was clear that providers had a statutory right to use ROWs for long distance without franchises and cities could not require franchise fees for long distance use, but to avoid delays of litigation, providers entered into "license" agreements with cities, which varied city to city.

Level 3 incorporated by reference those comments filed by the company on November 29, 2000, and reiterated its concern over the manner in which Texas' cities have interpreted HB 1777. Level 3 supported §26.465, believing the commission's proposed rules clarify the obligations and rights of the parties and eliminate many potential disputes concerning the use of the public ROW. However, Level 3 requested further direction from the commission. Specifically, Level 3 sought clarification on whether long-haul license agreements have any effect once a CTP establishes access lines and the CTP begins reporting and paying ROW fees according to the terms of HB 1777.

Level 3 stated that it continues to have disputes with municipalities over defunct long-haul license agreements. Level 3 explained that some cities, citing Texas Local Government Code §283.054(a), are demanding long-haul ROW payments in addition to access line fees. Level 3 noted that §283.054(a) provides that a CTP may elect to terminate existing obligations that arise from an executed ROW agreement or ordinance by providing notice to the commission and the affected municipality by no later than December 1, 1999. Level 3 questioned what becomes of long-haul ROW agreements if a CTP did not have access lines prior to December 1, 1999, but subsequently establishes them.

Level 3 explained that it executed numerous long-haul agreements in order to obtain the right to construct its network on a "pass-through" basis, as well as local "franchise" agreements in municipalities where it planned to offer local services. Level 3 stated that in certain municipalities where the company initially executed only a pass-through agreement, it has subsequently installed local facilities and submitted quarterly access line reports and payments according to HB 1777. Level 3 believed long-haul license agreements should no longer have effect, regardless of the "opt-out" schedule of §283.054(a). Level 3 asked that the commission clarify that simply because a CTP did not have operational access lines that would trigger the application of HB 1777 as of December 1, 1999, it is not forever barred from the nondiscriminatory application of the HB 1777 mandate that payment based upon an access line count constitutes full payment for all usage of ROW in Texas.

The CLEC Coalition argued that if compensation is to be competitively neutral and nondiscriminatory, the commission cannot slice and dice CTPs based on past history, and since in today's competitive environment CTPs are providing integrated telecommunications services, they should be paying one uniform fee. The CLEC Coalition argued that the cities' base amounts should be revisited to include license revenues.

McLeodUSA opined that the statute expressly provides that the access line fees will cover all the CTP's telecommunications facilities within the city's public ROWs. McLeodUSA cited Texas Local Government Code §283.056(f) and argued that the first sentence of this provision makes clear that the HB 1777 fees were intended to replace all fees that municipalities had received for use of ROWs by "telecommunications-related businesses," not merely businesses providing local exchange service, and the second sentence makes clear that the HB 1777 fees are to cover not only the use of ROWs for end-user lines themselves, but also for the interoffice facilities and other network infrastructure that is required to provide telecommunications services, but may not fall within the definition of an "access line."

McLeodUSA cited §26.463(c)(1)(B) and argued that it is, at best, unclear whether fees received under a long distance license agreement should have been excluded, or continue to be excluded, from the base amount, where the CTP has lines within the city that do meet the definition of "access line." McLeodUSA contended that whether a city could have included those fees in its base amount, and whether any increase in base amounts would be lawful, the statute itself is clear that a city is limited to collection of per-access-line charges for a CTP's use of public ROWs within the city for the provision of "telecommunications services," not merely local services.

McLeodUSA asserted that any other interpretation would be discriminatory and violate the competitively-neutral fee system that Chapter 283 was intended to create, and that any other interpretation represents an insurmountable and discriminatory burden for competitors that invested in and deployed network facilities in Texas before the Chapter 283 fee system was put in place and found themselves party to long distance license agreements in the process. McLeodUSA contended that separate payments, in addition to Chapter 283 fees, for use of public ROWs to provide long distance services would not be sought from a competitive carrier who constructs network facilities today within a city's public ROWs and uses those facilities to carry both local and interexchange traffic.

McLeodUSA contended that under Texas Local Government Code, Chapter 283, the only fees that a city is allowed to collect for the use of public ROWs to provide telecommunications services are the access line fees authorized by that chapter. McLeodUSA cited §283.056(a)(1) and asserted that this statutory prohibition on additional charges is not limited to a CTP's use of public ROW to provide local telecommunications services, but encompasses "telecommunications services" without limitation.

McLeodUSA requested the commission make explicit that a municipality may not collect fees from a CTP for use of public ROWs under a long-distance license agreement, or similar agreement, in addition to per-access-line charges under Chapter 283. McLeodUSA argued that cities may be expected to take the position that, even in its present proposed form, §26.465(d)(1)(C) merely provides that the per-access-line fee constitutes full compensation for all of a CTP's facilities located within public ROWs, insofar as they are used to provide local exchange service. McLeodUSA recommended the following additional amendment to §26.465(d)(1)(C), ". . . the per-access-line fee paid by CTPs constitutes full compensation to a municipality for all of a CTP's facilities located within a public right-of-way and *used to provide any type of telecommunications services*, including interoffice transport and . . . ."

McLeodUSA stated that alternatively, it joins Level 3 in requesting the commission make explicit that a city may not enforce or collect fees under a long distance license agreement from a CTP that has established access lines within the city. McLeodUSA argued that where a CTP has lines within the city that do not meet the definition of access lines under Texas Local Government Code §283.002, the only fee that the city may collect from the CTP for the use of the ROW to provide telecommunications services in the city, whether they are local or long distance or both, is the access line charges under Chapter 283.

McLeodUSA argued that the attempt by certain cities to continue enforcement of so- called "long-haul" license agreements, executed prior to implementation of the Chapter 283 regime, against CLECs who now are using public ROWs within a city to provide both local and long-distance service is an issue that threatens to undermine the proposed language.

*Municipalities*

Houston stated that, beginning in November 1998, under its telecommunications ordinance, the city entered into non-LEC franchise agreements. In addition, Houston asserted that they have collected non-LEC telecommunications franchise revenues in excess of $1.6 million dollars during 1999 and $2.6 million dollars during 2000. Therefore, Houston stressed that the adoption of any rule that caused the loss of these revenues would have a fiscal impact on the city and cannot implement the intended revenue neutral design of HB 1777.

Houston offered the following clarifying language for proposed §26.465(d)(1)(C): "Nothing herein contained shall be construed to limit the right of a municipality to receive fair and just compensation for the use of its ROW by all telecommunications providers to only those amounts which a CTP serving customers via access lines within a municipality must pay to that municipality pursuant to Chapter 283 Texas Local Government Code." Furthermore, Houston proposed also amending §26.465(f) by inserting the above statement.

Houston stated that it opposed McLeodUSA's position. Houston stated that a company that was a long-haul company and now has access lines in the city should report and pay for the access lines and continue to pay for the long-haul business. Houston asserted that the non-LEC telecommunication franchise revenues that it discussed in comments refers to franchise revenue from agreements with IXCs.

Irving contended that it distinguishes between requests for permits by CTPs for facilities to deliver local service to end users and requests for permits from non-CTPs or for facilities that are not intended to deliver service to end users. Irving stated that it takes the requestor's intent to provide end-use service at the requestor's word and it does not ask for an estimation of how long it will take to begin providing service to end-use customers. Both Houston and San Antonio agreed that they handle permits in the same way as Irving.

San Antonio stated that prior to the state's adoption of HB 1777, it approved and executed several long distance licenses that were based on a per linear-foot charge, and which expressly prohibited the provision of local exchange service without further consent of San Antonio via a franchise agreement. San Antonio further contended that although HB 1777 expressly prohibits it from requiring a franchise, these agreements were negotiated in good faith and the per linear-foot fees generated from these agreements were not included in San Antonio's 1998 base revenue calculation. San Antonio argued that if it were to lose the ability to enforce these agreements, it would not be compensated for this use of public ROW, which would not result in a revenue neutral impact to the City of San Antonio.

San Antonio argued that, as defined by HB 1777, the term "certificated telecommunications provider" is narrow in scope, in that it is the authority given by the commission to provide local exchange telephone service. San Antonio contended that the rules should utilize language that is reflective of this scope, specifically by not allowing companies to use their designation as a CTP to terminate these long distance license agreements. San Antonio further stated that HB 1777 only gave providers the right to unilaterally terminate franchises by December 1, 1999, not long distance license agreements. San Antonio opined that if the commission proceeds to adopt a new rule, specific language should be included recognizing the right to enforce per linear-foot long distance license agreements.

The Coalition of Cities argued that changing the compensation to include license revenues should occur by a change in the law rather than an interpretation of the law by the commission.

*Commission Response*

By its own words, HB 1777 relates to the provision of local exchange service. The provisions of Texas Local Government Code §§283.002(1)(A)(i), 283.002(2), 283.002(5), 283.006, and 283.051(b) clearly indicate that Chapter 283 is applicable to local exchange service and to nonswitched lines but not to switched interexchange lines. The statute clearly excludes lines covered under long-haul license agreements from consideration in the municipal base amount. Any other reading would require constant re-evaluation of the 1998 municipal base amount, which is clearly outside the intent of the statute. Texas Local Government Code §283.054(a) grants CTPs the option to terminate a franchise agreement or obligations under an existing ordinance as of the effective date of the commission-adopted ROW fee rates.

The commission has consistently maintained this position since being delegated responsibility for developing rates under HB 1777. In the October 21, 1999 Order adopting §26.463, the commission stated, "The commission is persuaded that the base amount should not include fees from CTPs that are interexchange carriers, cable providers or wireless providers. Access lines belonging to IXCs, cable providers, and wireless providers generally do not meet the statutory definition of 'access lines' under HB 1777. If the commission were to include compensation from these providers, but exclude their access lines, based upon the statutory definition of 'access lines,' the burden of compensating the municipality for use of the ROWs would be shouldered inequitably by ILECs and CLECs. To obtain consistent results, it is appropriate to include only providers whose access lines meet the definition of access lines as defined by §283.002 of the Texas Local Government Code. Through this approach, the commission will ensure that the base amount is comprised of monies from the same providers over whose access lines these fees will be spread. Therefore, the commission revises the definition of base amount to exclude fees from IXCs, cable and wireless providers who may be CTPs, but whose lines do not meet the definition of access lines. Compensation from these providers will continue outside the framework of HB 1777." This portion of the Order is incorporated in the commission's adopted rules. Section 26.463(c)(1)(B) reads, "The base amount does not include compensation received from interexchange carriers, cable provider or wireless providers, who may be CTPs, but whose lines do not meet the definition of access line under Texas Local Government Code §283.002."

The commission has continuously held that the option to terminate a franchise agreement or obligations under an existing ordinance as of the effective date of the commission-adopted ROW fee rates, related only to franchise agreements relating to the provision of local exchange service. Consistent with this position, as recently as April 23, 2001, in a letter discussing a dispute between a municipality and a provider, staff disallowed the late inclusion of license fees attributable to long distance lines in the municipal base amount. Commission staff contended that regardless of whether the telecommunications provider is certificated by the commission, under Chapter 283 and commission rules, long distance lines are excluded. Contrary to the assertion that the access line charges that a CTP pays to municipalities should constitute full compensation for all use of the public ROW, the statute and rules exclude long-haul lines from the framework. Allowing providers to include lines compensated under long-haul license agreements in this framework would subvert the intent of the law and the policy of the commission.

The commission provided the following to ensure correct calculation of base amount by all municipalities: (1) well-attended workshops held across the state in conjunction with TML throughout 1999; (2) individual calls and conference calls conducted by commission staff; and (3) mail-outs to every municipality in the state that included directions to the website for the "INSTRUCTION PACKET FOR FORM FOR CALCULATING RIGHTS-OF-WAY COMPENSATION AND PROGRAM FOR CALCULATING RIGHTS-OF-WAY COMPENSATION." The forms themselves were also located on this website, as well as contact information on a commission representative assigned to answer questions. Within the definitions section of the instructions packet is the statement: ". . . Base Amount . . . does not include compensation from interexchange carriers, cable providers, or wireless providers, who may be CTPs, but whose lines do not meet the definition of access line under Local Government Code §283.002." There can be no doubt that these instructions, and the painstaking efforts put forth by the commission to communicate them, clearly define the requirement to exclude fees from long-haul license agreements from the base amount calculations.

Despite certain superficial similarities, access lines passing through a city to provide local exchange service in another municipality are not the same as long-haul or long distance lines. Compensation issues regarding long-haul and long distance lines are outside the scope of the statute, outside the scope of these proposed rule amendments, and outside the scope of this proceeding.

The commission has steadfastly found that long-haul long distance lines are not within the purview of HB 1777. Accordingly, contracts or license agreements related to such long-haul long distance lines are not covered by the statute. As such, §283.054 did not create a termination right as to contracts or license agreements for long-haul long distance lines. In response to parties' concerns of the status of existing and future contracts, the commission, through this rule or previous rules, has taken and continues to take no position regarding the status of contracts governing long-haul long distance lines, as they are outside the purview of the commission.

*Statutory Deadline of License Agreements*

Parties submitted comments as to whether the rule provides for any extension of the deadline in which CTPs could terminate franchise agreements.

Irving stated that it did not understand that there was any consideration of extending the statutory deadlines for ending a license agreement and read all comments on such as being outside the scope of comments. Houston argued that CTPs do not have a springing right to reject a long-haul agreement if their business plan has changed.

McLeodUSA clarified that it is not seeking a springing right to extend the time in which it could terminate agreements, but instead recognition that its license agreements were terminated in a timely manner.

*Commission Response*

The commission makes no changes in response to these comments. The commission has not considered any extension of the deadline in which CTPs could terminate franchise agreements. This issue is outside the scope of this proceeding.

*Issuance of Permits by Cities with Outstanding Long-haul License Disputes*

Parties submitted comments regarding the issue of cities' rights, or lack of, to withhold ROW permits based on outstanding disputes with CTPs.

*Industry*

The CLEC Coalition maintained that some municipalities have required payment of up-front fees before they will issue a construction permit until the CLEC can prove to them that they will in fact be serving end-use customers. The CLEC Coalition noted that several cities have denied construction permits to CTPs unless the CTP agreed to pay up- front per linear-foot and further noted that the issuance of the construction permit was conditioned upon annual per linear-foot fees until the CTP demonstrated that it was serving end-use customers within this municipality. The CLEC Coalition stated that some CTPs that have been denied construction permits are new telecommunications service providers who entered the telecommunications service market after the passage of the Federal Telecommunications Act of 1996 (FTA 96) and others are newly certificated to provide local exchange service but are not new to the telecommunications service arena. The CLEC Coalition noted that some CTPs in this position might be former interchange carriers (IXCs) or competitive access providers (CAPS) who are expanding their existing networks. Regardless, the CLEC Coalition noted that whether the CTP is new to telecommunications or whether the CTP previously provided long distance services, the CTP is building or expanding a network that typically spans several contiguous cities. The CLEC Coalition argued that networks are designed and engineered to reach as many persons as possible and therefore backbones are built in rings before laterals are installed to end-use customers' premises. The CLEC Coalition concluded that Chapter 283 is clear in its prohibition of additional fees and indicated the proposed amendment to §26.465 properly interprets Chapter 283 and should be adopted.

Level 3 requested that the commission mandate that cities cannot terminate CTPs' ROW rights if disputes arise that relate to issues being addressed in the proceeding.

McLeodUSA requested the commission make explicit that a city may not deny a CTP access to public ROWs, and may not delay or deny issuance of permits to a CTP to work in public ROWs, on the basis of a claim for money owed to the city, so long as the CTP is current in its Chapter 283 per-access-line fee payments to the city.

McLeodUSA posited that, in addition to setting forth the fees, a CTP is obligated to pay a city for use of its ROWs. McLeodUSA contended that Chapter 283 limits a municipality's ability to deny a CTP's permit requests. McLeodUSA cited §283.056(d), and argued that under the plain language of this provision, a city is required to promptly process a CTP's applications for permits provided that they are valid and administratively complete. McLeodUSA contended that the fact that a CTP may not agree to pay long distance license fees under license agreements that the CTP genuinely believes to have been terminated pursuant to Chapter 283 does not make the CTP's permit applications any less valid or administratively complete. McLeodUSA asserted that a city must not be permitted to hold up a CTP's use of ROW, which may be required in order to conduct necessary provisioning and maintenance work, to gain leverage over the CTP related to a disputed claim for long distance license fees or other monetary claims.

McLeodUSA argued that Chapter 283 does not permit a city to diagnose the type of telecommunications service to be provided through a CTP's use of the public ROWs and to impose separate licensing (and fee) requirements where that use includes long distance service, and that the only regulatory requirements that a city may impose for a CTP's use of public ROWs to provide telecommunications service are the nondiscriminatory issuance of a construction permit and the competitively neutral enforcement of police power regulations to the extent reasonably necessary to protect public health, safety, and welfare.

McLeodUSA requested language for clarification from the commission that a city (1) may not delay or deny a CTP's application for a permit to use public ROWs to provide telecommunications services on the grounds of nonpayment of long distance license fees and (2) may not impose a separate license requirement for a CTP's use of public ROWs within the city, based on the fact that the particular facilities for which the CTP seeks access to the public ROWs will be used, in whole or in part, to provide telecommunications services other than local exchange service.

*Municipalities*

San Antonio requested that any proposed rule relating to penalties specifically recognize the local government's right to deny permits based upon a relevant failure of the CTP to operate lawfully in the public ROW, so long as denials are based upon a uniform, non-discriminatory process. San Antonio agreed that all penalties should be applied uniformly to all CTPs, and anticipated the challenge of determining when it can and cannot deny a ROW use permit as a form of penalty. San Antonio argued that although HB 1777 gives a CTP the "right" to use the ROW, this "right" is limited by the city's ability to police and manage its ROW. San Antonio contended that the ability to rightfully deny a permit based upon a failure of a CTP to abide by city laws, policies or agreements of the city is founded upon the city's ability to manage its ROW. San Antonio discussed that a situation in which it might consider denying a permit as a form of penalty could be when a CTP has failed to abide by a valid license agreement. San Antonio stated that "this begs the following question: if a CTP has an existing valid long distance license agreement and breaches that agreement, can the city deny a ROW use permit to that CTP?"

*Commission Response*

As addressed in the commission's response to comments regarding proposed §26.469, the Legislature expressly reserved to municipalities those police power-based regulations in the management of a public ROW. Please see the commission's response to comments on proposed §26.469 for further elaboration.

*§26.469, Public Right-of-Way Fees and Penalties*

The new §26.469, as proposed, clarified the definition and applicability of fees and penalties as these relate to municipal compensation and ROW management. However, the commission withdraws this section.

GENERAL SUPPORT AND ARGUMENTS FOR §26.469

The following parties filed written comments in support of the commission's proposed new §26.469: State of Texas, TSTCI, WorldCom, Level 3, Verizon, AT&T, CLEC Coalition, and Sprint. WorldCom, Verizon, and AT&T expressed concerns with the proposed language as written.

*State of Texas*

The State of Texas supported the commission's proposed new §26.469 because it clarifies applicability of fees and penalties for use of the ROWs and stated that the provision will promote healthy competition by appropriately addressing the issues of nondiscrimination and the rights of municipalities to manage the public ROW.

*Industry*

TSTCI generally supported the draft rule, as written. TSTCI stated that new §26.469 provides a valuable clarification that will prevent current and future confusion as to what fees and assessments fall under the umbrella of the municipal access line fees.

WorldCom commented that in §26.469(c), "fees" are defined as compensation for the use of the public ROW but that, technically, application fees are not for the use of ROW. Rather, they are to compensate the municipality for the costs of processing the application or registration and are paid whether the ROW is actually used. WorldCom noted that in §26.469(d), application fees are specifically excluded and suggested that the intent of the subsection may be clarified if the definition of "fees" is expanded to include application and registration charges. In addition, WorldCom noted that the defined terms "Fees" and "Penalties" are not capitalized consistently throughout §26.469. WorldCom suggested modification to §26.469(d)(1), line 1, to change the term "any compensation" to "fees" and to add "registration" to the list of prohibited fees. The commission understands WorldCom's comment to suggest that §26.469(d)(1) would then read that a municipality may not require a CTP to pay fees other than the per- access-line franchise fee authorized by Texas Local Government Code §283.055, for the right to use a public right-of-way to provide telecommunications services in the municipality. In accordance with Texas Local Government Code §283.056, such prohibited fees include, but are not limited to, application, franchise, license, permit, approval, excavation, inspection, registration, or other similar fees or charges.

With regard to §26.469(d)(2), WorldCom recommended that in line 2, "for municipally owned poles" be added after "pay pole rental fees." As well, WorldCom expressed concern that it is not clear as to what the term "special assessments" includes in the context of §26.469(d)(2). WorldCom commented that in §26.469(e), penalties do not go far enough in establishing guidelines, and the company recommended that basic due process requirements should be included in all penalty sections. Although WorldCom did not provide any suggested language to be added to the rule text, it did provide an example: "before a penalty is assessed there should be written notice describing what action or failure to act gave rise to the proposed penalty. There should be an opportunity to cure as well as a stated right to an administrative appeal. The description of the alleged breaches or defaults which gave rise to the penalties must be clear and unambiguous and the penalties must be reasonable and appropriate to the breach or default."

Level 3 incorporated by reference those comments filed by the company on November 29, 2000, and reiterated its concern over the manner in which Texas cities have interpreted HB 1777. Level 3 supported §26.469, believing that the commission's proposed rule clarifies the obligations and rights of the parties and will eliminate many disputes concerning the use of the public ROW. Level 3 wanted access to their networks protected even if disputes arise with cities. Level 3 asked that the commission prohibit municipalities from terminating CTPs' ROW rights if disputes arise that relate to issues being addressed in this proceeding. Level 3 stated that CTPs have invested vast amounts of capital constructing their networks and must be assured access to those networks and related ROW, that CTPs must have commercial certainty of the operating environment in the state of Texas, and that if an impasse occurs between a city and a CTP, the CTP must be guaranteed the opportunity to bring the issue before the commission for resolution without fear that access to the municipal ROW, and indirectly its network, is in any way impaired.

Verizon reiterated comments made in their November 29, 2000 filing, stating that criminal or civil penalties for violation of the ROW management ordinances may conflict with HB 1777's "full payment" requirement to cities for use of the public ROW as provided in Texas Local Government Code §283.056, which states that the compensation paid under this chapter constitutes full compensation to a municipality for all of a CTP's facilities located within a public ROW. On the other hand, Verizon argued that if it is determined that criminal or civil penalties can be assessed, these penalties could only be assessed when a municipality's policy is written and publicly available. Section 26.469 was proposed by the commission to state that to the extent elsewhere authorized by law, a municipality may assess penalties against a CTP for violations of a municipality's public right-of-way management ordinance or other written municipal policy. Verizon suggested adding to subsection (e)(1): "that are reasonably necessary to protect the public's health, safety and welfare and are not unreasonable or discriminatory." Verizon stated that this language is contained in Texas Local Government Code §283.056(c) and should be the minimum threshold for adoption of any ROW management ordinance or other rules by a municipality.

AT&T supported §26.469, but stated that the proposed rule fails to limit the amount of penalties that can be assessed against an alleged violator, which have ranged from $500 to $1000 per day for even the slightest and most harmless infraction of a ROW management ordinance. AT&T suggests it would be beneficial if the rule provided guidance to municipalities on the maximum level of penalties and the types of infractions for which penalties are reasonable and justified. AT&T suggested that a $500 to $1000 per day penalty for an administrative oversight infraction, such as providing 28 days notice instead of 30 days notice, is unduly burdensome and unlawful. AT&T stated the rule also fails to provide guidance as to when a violator has a right to due process of law or when such rights should be observed. AT&T noted that many municipal ROW management ordinances do not require the officials to provide the alleged violator notice of the alleged violation, an opportunity to cure the alleged defect, or an opportunity to be heard prior to assessing the fine or penalty. AT&T noted that the by-product of such discretion increases the likelihood and potential for the arbitrary and capricious application of fines and penalties, which could lead to expensive litigation and numerous complaints to the commission. AT&T recommended the rule require municipalities to provide alleged violators: (1) reasonable notice of the alleged violation; (2) a reasonable opportunity to be heard; (3) a reasonable opportunity to cure the alleged violation; and (4) the right to appeal a fine or penalty after it has been assessed. AT&T stated that such requirements would protect the integrity of the ROW management process and would promote better relations between the ROW user and the governing municipality.

The CLEC Coalition urged the commission to adopt the proposed amendment to §26.469, stating that it is consistent with Texas Local Government Code, Chapter 283, it provides clarification, and will serve to avoid future confusion concerning fees and penalties. The CLEC Coalition suggested that the term "franchise" be deleted from proposed §26.469(d)(1) and (e)(3).

Sprint commented that the new §26.469 represents a fair standard in which to interpret the intent of HB 1777, makes clear which access lines are subject to the provisions of HB 1777 and fairly identifies what fees and penalties can and cannot be assessed by cities. Sprint asserted that the proposed rule strikes a fair balance between municipal interests and the enhancement of competition.

GENERAL OPPOSITION AND ARGUMENTS AGAINST §26.469

The following parties filed written comments in general opposition to the commission's proposed new §26.469: SWBT, Coalition of Cities, TML, TCCFUI, Houston, Plano, and Garland.

*Industry*

SWBT requested the commission not adopt proposed new §26.469 because it is neither necessary nor appropriate to implement the policy of Chapter 283, nor is it needed to ensure competitively neutral, non-discriminatory, or reasonable enforcement of requirements enacted by municipalities under their authority to manage the public ROWs. SWBT argued that Chapter 283 does not contain a definition for "fees" or "penalties." Therefore, the commission's action in assigning definitions to these terms could result in an inadvertent expansion of the municipal authority that is granted by Chapter 283. SWBT suggested that proposed new §26.469 actually endorses municipalities' intent to view the term "penalties" broadly, thereby resulting in assessment of additional fees for a CTP's presence in the public ROWs. SWBT recommended that because this is an inappropriate topic under implementation of HB 1777, and because authority to assess any such penalties would be based upon other areas of the law outside of Chapter 283, the commission should not adopt §26.469.

SWBT referenced Texas Local Government Code §283.053 which describes the items that shall not be included in the calculation of a municipality's "base amount," including "pole rental fees, special assessments, and taxes of any kind, including ad valorem or sales and use taxes, or other compensation not related to the use of a public right-of-way." SWBT asserted that just because these items are not to be included in the "base amount," it does not automatically provide the commission with the jurisdiction to grant municipalities the right to require payment of these fees, as stated in proposed §26.469(d)(2). SWBT made three points: (1) to the extent municipalities have the right to exact any of these stated fees, the right exists elsewhere in the law and is not the subject of Chapter 283; (2) Chapter 283 does not authorize the commission to sanction municipal penalties, and to the extent a municipality is authorized to impose penalties for non-compliance with municipal ordinances, the authority exists elsewhere in the law and is not a proper subject for commission rules; and (3) §26.469(e), as proposed, expands on the limitations of §283.056(c). Therefore, SWBT argued that the commission should not adopt §26.469. Rather, SWBT urged that both the penalties and the enforcement of the penalty against a CTP, as well as all ROW management regulations, must be lawful and reasonable, as well as competitively neutral and nondiscriminatory.

*Municipalities*

The Coalition of Cities agreed with and adopted the comments as filed by the TML, TCCFUI, Plano, Garland, and San Antonio in their opposition to the new proposed §26.469. The Coalition of Cities asserted that the proposed rule is outside the scope and intent of HB 1777, that the commission was not granted any jurisdiction over cities in HB 1777 to authorize or not authorize such penalties - nor to set standards for penalties. The Coalition of Cities stated that most of the proposed rule is simply a repeat of the current statute and therefore unnecessary. The Coalition of Cities stated that it was specifically opposed to the entire subsection (e), as it seems to equate "compensation," as referred to in HB 1777, with "penalties." The Coalition of Cities stated that "penalties" are not in any way a form of compensation for use of the ROW and argued that HB 1777 only addresses compensation for ROW use. The Coalition of Cities asserted that Chapter 283 does not even allude to penalties and that penalties are imposed by cities under other specific statutory authority such as Texas Local Government Code, Chapter 54, Enforcement of Municipal Ordinances, and under general police powers authority. The Coalition of Cities gave several examples of when a city may impose a penalty on a provider and the form a penalty may take.

The Coalition of Cities stated that they know of none of their members who charge prohibited fees. The Coalition of Cities argued that, as the access line fee is structured to replace any franchise fees or permit fees that were charged for "use of the public rights- of-way" prior to Chapter 283 and as the Base Amount for municipalities excluded "pole rental fees, special assessments, taxes of any kind, including ad valorem or sales and use taxes, or other compensation not related to the use of the public right-of-way," those fees and compensation may still be charged. The Coalition of Cities asserted that this statutory language is reflected in the proposed rule at subsection (d)(2), and that it agrees with this provision. The Coalition of Cities maintained that the prohibited fees do not bar generally applicable fees that would generally apply to either private property or public property construction. The Coalition of Cities argued that, in light of these provisions, Austin continues to assess an annual "environmental review" fee. The Coalition of Cities asserted that federally mandated environmental standards require the City of Austin to stringently enforce rules enacted to protect the watershed from runoff associated with excavation on private and public property, and that this environmental review is required regardless of whether excavations are performed on public or private property. The Coalition of Cities maintained that this fee has no association with a CTP's "use of the ROW" and that this fee helps defray the cost of enforcing these environmental regulations and is also intended to pay for City staff time used in the development of environmental regulations compliance strategies with construction entities. The Coalition of Cities contended that, as a "cost recovery" tool, the environmental review fee was never a part of the "compensation received for use of the ROW" equation established under HB 1777. The Coalition of Cities also stated that a fee may be charged for the service of expediting the permitting process.

The Coalition of Cities argued that cities may also recover cost from contractors or owners for any damage to public property arising due to construction in the ROW, all in accordance with the indemnity sections of §283.057. The Coalition of Cities asserted that some cities have considered, and may be implementing, charges to recover additional costs to the city caused by all street utility cuts for repaving the streets. The Coalition of Cities maintained that, while no one would argue that if a street cut is not done properly, the city could require that the CTP repair it or in the event they did not repair it, the city could repair it itself and receive a reimbursement from the CTP for this repair cost. The Coalition of Cities contended that the same holds true if a street has multiple street cuts on it and needs to be repaved earlier than expected. The Coalition of Cities argued that those additional costs for the repaving may be recovered from those who caused it, and that Chapter 283 does not prohibit such cost recovery. The Coalition of Cities stated that while it did not agree with all reasons given by SWBT in its opposition to the proposed §26.469, it did agree with SWBT's comments that Chapter 283 does not refer to the application of penalties, that such a topic of penalties is not an appropriate topic under implementation of HB 1777, and that the commission should refuse to adopt the new §26.469. The Coalition of Cities stated that it disagreed with the comments filed by AT&T, WorldCom, and Verizon that the commission should establish more details and further restrictions on cities as to penalties.

TML argued that proposed §26.469 would accomplish little or no purpose. TML argued that subsections (a)-(c), (d)(2), and (e)(4) merely re-state legal principles or definitions already contained in the law or Chapter 283. TML contended that subsection (e)(1) purports to grant authority to cities to impose penalties that the cities already have by statute. TML asserted that all of proposed §26.469 should be deleted except proposed subsection (d)(1). TML supported subsection (d)(1) as clearly stating its position that a municipality may not charge fees for the right to use ROWs other than access line fees for the right to use ROWs to provide telecommunications services in the municipality. TML argued that this is the correct interpretation of HB 1777 and that the converse is that a city may charge fees other than access line fees for the right to use ROWs by entities that do not provide telecommunications services in the city.

TML argued that proposed §26.469 demonstrates a lack of experience with municipal issues, and may exceed the commission's authority. TML argued that subsection (e)(2) seems to reverse the federal and state statutory requirements for competitive neutrality and non-discrimination respecting restrictions on the use of public ROWs. TML asserted that subsection (e)(2) apparently requires misconduct in the public ROW by CTPs to be competitively neutral and non-discriminatory in order that cities may sanction them accordingly, because a city's imposition of sanctions for misconduct provides specific and general punishment for past actions and deterrence against future misconduct. TML argued that "Such penalties will, and must, single out the perpetrator for discriminatory treatment. To suggest that cities must impose penalties on a non- discriminatory and competitively ignores and reverses the purpose of imposing penalties."

TCCFUI argued that proposed §26.469 is unnecessary, and that, although it may be designed to support the assessment of penalties by municipalities, it instead opens the possibility for future erroneous arguments that the commission intended to change the meaning of the statute and expand the role of the commission. TCCFUI contended that the law does not require or support the provisions of the new rule. TCCFUI maintained that proposed §26.469(e)(1) exceeds the commission's authority by purporting to grant sanction power to the cities that the cities already have by statute. TCCFUI contended that §26.469(e)(2) perverts the federal and state statutory requirements for competitive neutrality and non-discrimination respecting restrictions on the use of the public ROWs into a requirement that sanctions for misuse of the public ROW or for misconduct by CTPs in the public ROW be competitively neutral and non-discriminatory. TCCFUI asserted that this approach ignores the fact that as a matter of law, in the exercise of its police powers after adequate due process, a city can and should impose sanctions for misconduct by CTPs that are intended to provide specific and general deterrence as to future misconduct, as well as compensation for past misconduct and that any such sanctions will inevitably, and justifiably, single out the miscreant for discriminatory treatment and could make it difficult or even impossible for the wrong-doer to compete in the future.

TCCFUI requested that §26.469 not be adopted. TCCFUI urged the commission not to diminish or take away local control of ROW management, which TCCFUI argued is the only way a ROW can be properly managed. TCCFUI contended that HB1777 confirmed local management of the ROW as a state policy, and the complexity and variety found in Texas localities demands local solutions to unique problems. TCCFUI asserted that, to the extent the commission wishes to support the ability of local governments to manage the ROW and assess penalties for violations of ROW ordinances, a simple statement of support would be preferable. To the extent not inconsistent herein, TCCFUI supports the positions of TML and the Coalition of Cities.

Houston stated the proposed new §26.469 appears unnecessary and in its current form provides no new guidance toward implementation of HB 1777 that is not already clearly present in HB 1777. Houston suggested that the proposed new §26.469 be deleted in its entirety.

Plano asserted that proposed new §26.469 is unnecessary, as the language of the proposed rule that addresses fees is merely a restatement, almost verbatim, of the provisions of Texas Local Government Code §283.056, and does not set any "standards for fees" as stated in the preamble to the proposed rules. Plano further asserted that the language of the proposed rule that addresses the assessment of penalties by a municipality is unnecessary and does not implement any portion of HB 1777. Plano argued that HB 1777 governs compensation for use of public ROWs and not the payment of penalties for the violation of city ordinances. Plano asserted that while it has been authorized to adopt rules implementing HB 1777, the commission has not been authorized to adopt rules addressing the ability of a municipality to enforce its ordinances. Plano argued that Texas Local Government Code §54.001 provides general enforcement authority for rules, ordinances, and police regulations to all municipalities including the imposition of penalties for violations of ordinances. Plano opined that there is no need for a commission rule authorizing municipalities to enforce any ROW management ordinances and impose penalties therefor. Plano supported the comments of TCCFUI that, if the commission desires to support the ability of municipalities to manage the ROWs and assess penalties for violations of ROW management ordinances, a simple statement of support is preferable.

Garland agreed with the comments filed regarding the proposed new rule that such rule is both unnecessary and unnecessarily confusing. Garland supported the comments filed in this respect by TML, TCCFUI, Coalition of Cities, San Antonio, and Plano. Garland suggested that §26.469(c) requires some clarification in order to avoid confusion. Specifically, Garland contended that, as the Texas Attorney General recently opined, Texas Local Government Code, Chapter 283 applies only to municipal regulations and fees imposed on and collected from CTPs. Garland, therefore, endorsed that the proposed rule be clarified to only apply to access line fees imposed on CTPs. Garland expressed concern that this proposed section, as written, could be interpreted to require municipalities to impose uniform fees on CTPs, electric providers, gas providers, cable television companies, and water and sewer companies. Garland suggested adding language so that the provision would read, "Fees - Compensation from CTPs to a municipality for the use of public ROW. Fees are uniformly applied to all similarly- situated CTP ROW users." Garland also stated the proposed rule is not necessary in order to give municipalities the authority to impose penalties for violations of municipal ordinances, as such authority already exists independently of HB 1777 and the rules adopted thereunder. Garland states, however, that since there are potential conflicting interpretations of municipalities' authority in this regard, the city supports §26.469(e) regarding the imposition of penalties on CTPs for violation of ROW management ordinances and other written municipal policies. Garland submitted that any municipal ordinance qualifies as a "written municipal policy" under this provision, and penalties are assessable against CTPs for any violation of any municipal ordinance.

*Commission Response*

Based on comments, the commission chooses not to adopt §26.469. The goal of the proposed rule was to address the issue of competitive neutrality and unreasonable or discriminatory regulation. In attempting to distinguish "fees" from "penalties," the commission sought to define previously undefined terms. As the comments reflect, there is a wide range of interpretation of these terms. To the extent elsewhere authorized by law, a municipality may exercise its police power-based regulation. Chapter 283 did not change that existing authority.

The commission in no way intended to diminish or take away local management of the public ROWs, as suggested by TCCFUI's comments. Moreover, the expressed concern of municipalities that §26.469 would have this unintended result is sufficient reason for the commission to withdraw §26.469 at this time. Therefore, the commission does not adopt §26.469.

UNIFORM PUBLIC ROW MANAGEMENT ORDINANCE

In the April 6, 2001 issue of the *Texas Register*, comments were solicited as to whether the commission should promulgate rules or create guidelines for a uniform public ROW ordinance to be adopted by municipalities in Texas.

GENERAL SUPPORT OF A UNIFORM PUBLIC ROW ORDINANCE

The following parties filed written comments in support of the commission promulgating rules or creating guidelines for a uniform public ROW ordinance to be adopted by municipalities in Texas: SWBT, WorldCom, CLEC Coalition, and Level 3.

*Industry*

SWBT asserted its support for uniform guidelines, arguing that such guidelines would be time and resource saving, especially for smaller municipalities; would assist in resolving disputes between municipalities and CTPs regarding the permissible level of ROW management authority; and could provide a forum for education and negotiation between municipalities and CTPs regarding their respective needs and limitations. SWBT disputed the municipalities' opposition to a uniform ordinance or guidelines as causing confusion due to differing authorities and needs. SWBT argued that this position by the municipalities is refuted by the fact that municipalities are sharing management guidelines and entire ordinances. SWBT provided its concept of the municipalities' concern as being who develops the guidelines rather than whether the guidelines exist. SWBT requested the commission to initiate the process to promulgate rules or guidelines to establish the perimeters for ROW management ordinances.

SWBT articulated its position as to the explicit limitations that HB 1777 places on municipalities' power to regulate the use of the public ROW and pointed out that in the same act, the Legislature limited municipal power at the same time it established a uniform mode of compensating municipalities for their administration of a CTP's use of the public ROW. SWBT provided an example to illustrate why it believes that the commission has authority to impose limitations on municipal ordinances through the adoption of commission rules. SWBT clarified in the public hearing that it did not suggest that there should be a uniform ordinance. However, SWBT believed that there are some common issues and that efforts by city staff and by their providers would be aided if the commission were to promulgate guidelines in the form of rules that would be maximums and minimums. SWBT expressed that these would not be compulsory and a city would not have to adopt anything.

WorldCom supported the concept of commission promulgation of rules or creation of guidelines for uniform public ROW ordinances to be adopted by municipalities pursuant to their police powers and consistent with Texas Local Government Code, Chapter 283. WorldCom stated that the promulgation of a uniform ROW management ordinance would eliminate disparate provisions that make it time consuming and complicated for CTPs to install facilities which traverse more than one municipality.

The CLEC Coalition supported the use of public ROW ordinances that are reasonable and that are applicable to all users of the public ROWs. The CLEC Coalition stated that both municipalities and CTPs would benefit if the commission developed certain limited standardized guidelines for ROW use ordinances regarding registration procedures, permit application procedures, evidence of insurance, and submission of as-built plans and if the commission explored the possibility of a centralized repository for evidence of insurance.

Level 3 argued that cities cannot be allowed to determine how much conduit a CTP may put in the ground. Level 3 contended that requiring cities to adopt uniform ROW ordinances will ensure that construction in city ROWs is allowed to proceed in a timely manner and on terms favorable to municipalities and the affected CTP. Level 3 maintained that a commission-ordered ROW ordinance would provide consistency. Level 3 asserted that any ordinance must relate to the city's control or use of its ROW, must not be used to supplement city coffers, and must be non-discriminatory and competitively and technically neutral.

GENERAL OPPOSITION TO A UNIFORM PUBLIC ROW ORDINANCE

The following parties filed written comments in support of the commission promulgating rules or creating guidelines for a uniform public ROW ordinance to be adopted by municipalities in Texas: TML, TCCFUI, Coalition of Cities, Plano, Garland, Houston, and San Antonio. Irving offered verbal comments at the public hearing.

*Municipalities*

TML asserted that the commission should not promulgate rules or create guidelines for a uniform public ROW ordinance to be adopted by cities in Texas. TML argued that any attempt to do so will provide the telecommunications industry with an opportunity to advocate positions and argument that are beyond the commission's authority to decide, will cost cities a great deal of time and expense to address, will burden the commission, and will interfere with the well-established authority of cities that is preserved in HB 1777. TML maintained that the details of ROW ordinances vary significantly from city to city based upon city type, home rule city charter provisions, local ordinances, geography, climate, geology, demographics, traffic considerations, infrastructure conditions, ROW capacity, and myriad other local factors. TML argued that by attempting to arbitrate and draft the ideal uniform ordinance, the commission would place itself in the business of deciding local issues, which it does not have the staff or responsibility to assume.

TCCFUI stated that there is no statutory support for a uniform ROW ordinance, no support from municipalities, and little or no support from telecommunications companies or industry groups for such an ordinance. TCCFUI stated that ROW management is a local concern and to establish a uniform ROW management ordinance would only create an ordinance that would be, at best, meaningless and could even endanger the public safety.

The Coalition of Cities stated that, while member cities have or will adopt individual ROW ordinances as they are beneficial to the cities and those excavating in the city ROW, it would oppose a commission rule requiring a ROW ordinance or guidelines for such an ordinance promulgated by the commission. The Coalition of Cities argued that §§283.001(b)(1), 283.056(c)(1)-(4), and 283.057 clearly preserve and reiterate the historic police powers of municipalities to manage the ROW. The Coalition of Cities contended that the few restrictions as to police power regulations in Chapter 283 are only as to a required business office, restriction on required reports, restriction on the inspection of business records and as to transfers and as to notice on emergency repairs, and that there is also a statutory indemnity. The Coalition of Cities stated that it agrees with the consensus of the comments at the workshop on this rule that there are numerous advantages to both cities and the industry in municipalities adopting ROW management ordinances. The Coalition of Cities maintained that, while it does not agree that the commission has jurisdiction to mandate such ordinances be adopted by cities and the Coalition of Cities would not support a rule requiring such an adoption by a municipality, it would not oppose a commission policy statement that it would be advantageous to both the industry and to cities for cities to adopt such a management of the ROW ordinance.

The Coalition of Cities asserted that, while there may be certain broad common elements in such a ROW ordinance, the details will vary significantly from city to city, as cities are unique across Texas. The Coalition of Cities argued that, if the commission chose to promulgate guidelines or a list of suggested "standard" provisions, those guidelines or that list would be deemed to be an exclusive list of what constituted "reasonable standards." The Coalition of Cities maintained that in the event that a city had additional or different details in its regulations that were not on the commission's "approved" list, such regulations may be challenged using the commission "approved" guidelines as the basis of an argument that the regulation was improper or "unreasonable." The Coalition of Cities stated that some in the industry have suggested that the FTA 96 limits city authority in this area, but that this assertion is not correct. The Coalition of Cities argued that the federal law also preserved the cities' ROW management authority. The Coalition of Cities cited a Dallas federal court case in which the court provided examples of how a city may manage its ROW. The court also commented on municipalities' historic rights to management of the public ROW being preserved in Texas law. The Coalition of Cities asserted that while courts in other jurisdictions have also reviewed these issues under federal law in the few cases where federal law has preempted city ROW ordinances, it has been where they were either vague, allowed unbridled discretion to city officials, or the regulations were unrelated to the ROW usage. The Coalition of Cities added that additional municipal ROW authority is allowed for in Texas Utility Code §181.089. The Coalition of Cities reiterated in the public hearing its opposition to a ROW ordinance or to a standard for ROW ordinances because, while cities do share their ROW ordinances, ordinances are specifically tailored to meet each city's needs, and are always changing to deal with their particular fact situation, particular geography, and particular density.

Plano argued that while there are numerous advantages to cities and industry in adopting ROW management ordinances and that while Plano itself has adopted a ROW management ordinance, Plano does not support a commission rule requiring cities to have a ROW ordinance due to the fact that it does not believe that the commission has jurisdiction to require such an ordinance. Plano contended that the ROW management needs of each city are unique to that city, and regulations that are appropriate for one city are not necessarily appropriate for another city. Plano applauded the commission for indicating on several occasions that it would not dictate the elements of cities' ROW ordinances, because by taking this approach, the commission recognizes the authority of cities to exercise their police power-based regulations in the management of the public ROWs as provided in Texas Local Government Code §283.001 and §283.056.

Garland stated that it believes a ROW ordinance is a reasonable and proper police power based management tool for Texas municipalities. Garland also asserted that the choices and decisions reflected in Garland's ordinance are exclusively within the authority of the City Council of the City of Garland and that nothing in HB 1777 diminished or restricted that authority. Garland concluded that the commission is without authority to either require that a municipality adopt a ROW ordinance or to dictate its contents. On this basis, Garland urged the commission to decline to issue any rules or directives in this regard.

Houston reiterated its opposition to the suggestion of the commission promulgating a standardized ROW ordinance. Houston argued that promulgating such a standardized ROW ordinance would potentially: (1) contradict the purpose of HB 1777; (2) exceed the scope of the commission's mandate to regulate CTPs under HB 1777; (3) create confusion over the interpretation of HB 1777 without contributing finality; and (4) involve the commission in matters outside its jurisdiction and expertise. Houston stated that the legislature provides no mandate for a commission promulgated standardized ROW ordinance within the plain meaning of HB 1777. Rather, Houston maintained municipalities should retain their traditional role as manager of their ROW and better meet the individualized needs of each municipality's unique characteristics. Houston stated that HB 1777 simply does not express a clear legislative intent to expand the commission's responsibility into the area of drafting a standardized ROW ordinance. Houston therefore, opposed any action by the commission that would require municipalities to adopt a commission-promulgated form of standardized ROW ordinance.

San Antonio argued that it does not support the passage of uniform public ROW ordinance rules or guidelines and that these issues are better reserved to the local governments to decide the best practices in managing and policing their ROW. San Antonio contended that both the FTA 96 and HB 1777 specifically recognize ROW management as an issue for local control and cited to *BellSouth Telecommunication v. City of Coral Spring & Town of Palm Beach*, Nos. 98-08232 and 99-14292 (11th Cir., filed May 25, 2001), which, it argued, supports local control of ROW management. San Antonio argued that its ordinance already accomplishes the goal of preserving its ROW management and police powers, while maintaining non-discriminatory treatment of CTPs.

Irving stated that it opposed guidelines.

*Commission Response*

The commission solicited comments regarding whether it should propose rules or guidelines discussing uniform municipal ROW management ordinances. Because municipalities strongly contend that any such rules or guidelines might infringe upon a municipality's police power-based authority, the commission will not issue guidelines regarding municipal ROW management ordinances at this time. The commission agrees that issues regarding ROW usage are both common among municipalities and unique to each municipality. The commission encourages CTPs and municipalities to work together in resolving these issues to mutually satisfactory solutions. The commission notes, however, that any police power-based regulation adopted to implement the provisions of Texas Local Government Code, Chapter 283 must be competitively neutral and may not be unreasonable or discriminatory.

CHALLENGE OF PREAMBLE ASSERTIONS

Leon Valley opined that the determinations offered in the preamble were incorrect because police power-based regulations cannot replace fees for use of ROW where a CTP is authorized by statute to run its cable through a city's ROW free of charge, even though the CTP does not provide end-user services within that city. Leon Valley argued that the retained right of cities to initiate legal action is hardly a useful right in that it suggests that the citizens should bear the double financial burden of having their collective private property taken by corporate entities and then having to pay again for litigation to attempt to regain that which should not have been taken from them in the first place.

Leon Valley stated that the commission offered zero empirical data and made no claim to have sought input from any municipality to use in the development of the determination that the fiscal impact of pass-through lines rests on the expectation of a municipality for a revenue amount rather than on a true impact to that amount.

Leon Valley argued that it is difficult to understand the reasoning of the statement that adoption of the HB 1777 rules will in any way result in a "public benefit" in the nature of "more efficient use of the public ROW" that will come "as a result of enforcing the sections." Leon Valley contended that the commission offered zero empirical data to support the statement that some municipalities and CTPs may even experience an economic benefit due to the clarity, consistency, and uniformity imposed in the amended and new rules.

Plano argued that cities will see an immediate fiscal impact if pass-through lines are assumed to be "paid for" when a CTP pays municipal fees to some city under HB 1777 because some cities are currently, or were previously, receiving compensation for the pass-through lines from providers pursuant to other types of licenses or agreements and the revenue received under those licenses or agreements will simply vanish since it has not been, and will not be, included in cities' base amounts. Plano further maintained that pass-through lines create a burden on cities' ROWs that is not merely an expectation of a revenue amount, in that the construction of lines that pass through the public ROWs often results, just as with lines that will be used to provide local exchange telephone service, in damage to public infrastructure and facilities owned by other utility and telecommunications companies. Plano contended that the municipal fees received by cities represent a portion of the funds used to maintain the public ROWs and public infrastructure, and that by allowing certain CTPs to use public ROWs in certain cities without compensating the cities, the proposed amendment to §26.465 destroys the revenue neutrality, competitive neutrality, and non-discriminatory policies on which HB 1777 was founded.

Plano referenced the preamble statement that the proposed amendment will result in a more efficient use of the public ROWs, but argued that there is no explanation as to what is meant by that phrase or how the proposed amendment to §26.465 will actually accomplish that goal. Plano asserted that any conclusions respecting the impact of the proposed amendment to §26.465 on the efficiency of ROW use are without foundation -- and therefore cannot be relied upon as a justification for the proposed amendment to §26.465 -- in the absence of any analysis of how telecommunication infrastructure installation, maintenance, repairs and other work impact competing uses of ROWs, particularly vehicular and pedestrian traffic and the exercise of the rights of peaceable assembly and free expression.

Plano stated that the proposed amendment to §26.465 would allow CTPs that pass through a city without providing local exchange service to citizens within that city to not compensate that city for the use of its ROWs. Plano asked if a CTP is not providing local exchange telephone service in a city, how could it be providing "greater accessibility to telecommunications services" to the citizens within that city or be "providing greater choice for telecommunications consumers?" Plano maintained that the only result from the adoption of the proposed amendment to §26.465 is that CTPs will be allowed by the commission to burden the cities' ROWs without paying *any* compensation to the city for their use of the ROWs -- which is in direct contradiction to the policy of the state, set out in Texas Local Government Code §283.001. Plano asserted that Chapter 283 leaves ROW regulation policy decisions where they belong, with the cities, and the commission has no authority to interfere with municipal ROW policies so long as the policies are competitively neutral and non-discriminatory. Plano argued that there is no claim that the proposed amendment to §26.465 is necessary to correct city policies that violate federal or state telecommunication law limits on city restrictions regarding the use of ROWs by telecommunications providers. Plano opined that the proposed amendment to §26.465, which is purportedly based on policy considerations that are within the sole purview of cities, would exceed the commission's authority.

TCCFUI cited the statement "The public also benefits through more efficient use of the public ROW" and argued that the proposed change does not make more efficient use of the ROW, just free use by some companies and that no supporting data showing such efficiency is offered. TCCFUI argued that the comments in the preamble to the proposed amendment that cities will receive economic benefit are without merit. TCCFUI cited the statement "some Municipalities and CTPs may even experience an economic benefit due to the clarity, consistency, and uniformity imposed in the amended and new rules" from the preamble and argued that though some companies will experience an economic benefit, cities will not. TCCFUI stated that no city so burdened by construction and deployment of facilities will benefit under the proposed amendment, and that not only does the city not receive payment for the use of the ROW, but the city's citizens do not receive services. TCCFUI argued that the spurious prediction of possible economic benefit contradicts the prediction of the fiscal neutrality in the fiscal note accompanying the amendment's proposal.

TCCFUI cited the statement "as a result of these decreased barriers to entry into the telecommunications market, telecommunications competition is likely to increase, thereby providing greater choice for telecommunication customers in Texas" from the preamble and argued that competition by multiple telecommunications companies was always more an unrealized promise and creature of available market financing. TCCFUI maintained that, except as a financial benefit to telecommunications providers and initial public offering (IPO) insiders, it was never about easy or free access to publicly financed ROWs. TCCFUI stated that the public continued to suffer for increased competition to fill the ROW with fiber, whether services are ever provided. TCCFUI contended that companies digging frequently deprive citizens of utility services due to severing existing facilities in overcrowded ROWs.

In its March 19, 2001 correspondence, TCCFUI expressed its belief that the proposed rule probably has a substantial local fiscal impact requiring a Texas Work Force Commission local employment impact statement as required under Texas Government Code §2001.022. TCCFUI also believed that Texas Government Code §2001.024(a)(4)(A) requires a more detailed and better supported local fiscal impact statement, including discussion of the anticipated major costs of litigating the validity of the new rule. Finally, TCCFUI asserted that the commission staff's March 13, 2001 memorandum is devoid of any factual substantiation of the absence of fiscal impact.

*Commission Response*

The commission finds that comments regarding the preamble statements apply to both the adopted amendment to §26.465 and the previously proposed new §26.469, which is being withdrawn. With this in mind, the commission disagrees with these comments.

The commission disagrees with the assertions of Leon Valley, TCCFUI, and Plano that the proposed amendment will not result in more efficient use of the public ROW or provide public benefit. This efficient use of the public ROW can be divided into two categories: efficiency through reduction of administrative costs and efficiency through optimization of the scarce resource of physical ROW space. In accordance with the Legislature's stated policies and purposes under §283.001, this amendment increases administrative simplicity and clarifies the equitable fee structure thereby reducing barriers to entry for CTPs seeking access to the public ROWs. The clarifying rule amendment informs all stakeholders, including the public, municipalities, and telecommunications providers, about the meaning of the statute. The efficiency gained through consistent interpretation and application of the law in itself constitutes a benefit for the public because it reduces administrative costs to all stakeholders, which includes savings to the rate-paying consumers. Moreover, reduced barriers to entry into the market leads to more CTPs being able to enter the market and use the ROW, thus leading to more efficient use of the scarce resource of physical ROW space due to economies of scale. The public will benefit through increased opportunity of competition in the telecommunications market due to optimization of ROW usage.

In contemplating the issues of economic benefit, the commission considered the various types, sizes, and unique challenges to various municipalities in the State of Texas. The commission specifically used the language "some municipalities . . . may even experience an economic benefit . . ." because "municipalities had various arrangements with CTPs prior to HB 1777" and "because HB 1777 provides uniformity for CTPs to gain access to all public ROW," therefore, "implementation of HB 1777 may have impacts that differ among municipalities." The stated policies and purposes of the statute apply across the entire state of Texas rather than to any particular municipality.

Consistently, the commission's position has been and is that the economic benefit will vary amongst municipalities. Some municipalities will gain revenue because, ultimately, the reduction of barriers to entry as clarified by the amendment to §26.465 will ease the additional deployment of facilities and create greater opportunities for the delivery of local exchange service. The increase in end-use access lines translates into economic benefit in the municipalities where those lines terminate.

The commission disagrees with TCCFUI that the prediction of possible economic benefit contradicts the concept of fiscal neutrality. The concepts are not mutually exclusive. The concept of revenue neutrality is only included in this rule amendment to the extent that the law provides for the municipalities to recover at least their 1998 base amount through the access line compensation regime, insofar as the access line fee multiplied over the number of access lines in each category does not fall below the 1998 level. There is no express promise of revenue neutrality anywhere in statute or rule. The economic benefits discussed by the commission in the proposed preamble are unrelated to the municipal base amount. The commission acknowledges that fiscal neutrality relates to the concept of "competitive neutrality" stated in the Legislature's purpose under §283.001. The base amount established under §283.053 and developed in commission rules incorporates the concept of fiscal neutrality in the calculation based upon 1998 revenues. The commission, therefore, finds that the economic benefit analysis does not contradict the concept of fiscal neutrality.

The Legislature expressly reserved to municipalities the specific authority to manage a public ROW to ensure the health, safety, and welfare of the public. Plano and TCCFUI refer to several burdens that fall upon the municipalities, such as construction, installation, maintenance, and repairs. The commission understands these burdens to be the responsibility of municipalities. The authority for addressing these burdens falls within the purview of municipalities under the police power-based regulations reserved to municipalities in §283.056(c). However, the commission disagrees with Plano's assertion that the statute leaves ROW regulation policy decision solely to the municipalities. The commission disagrees that the adopted amendment to §26.465 in any way exceeds the commission's authority established by the statute.

The commission asserts, again, that the rule amendment to §26.465 does not constitute or promote free use of the public ROW. For detailed analysis, see the commission's response to arguments for and against the adopted amendment to §26.465. The commission disagrees with Leon Valley's implication that the commission expects police power-based regulations to replace ROW compensation. No CTP is using the ROW "free of charge" under Chapter 283. The commission disagrees with Plano's assertion that there will be an immediate fiscal impact to cities when the commission adopts the amendment to §26.465(d). Pass-through lines are fully compensated under the access line compensation regime. There is simply no room in the language of the statute to allow additional compensation to be required for other access lines located in the public ROW under other ordinances or franchise agreements. The total access lines within the city and the total fees are a proxy for the compensation formerly received under the franchise regime. Therefore, a one-to-one correlation between access lines and municipal fees is unnecessary to ensure that a city receives adequate and appropriate compensation for use of the public ROW by CTPs. This is not "free use" of the ROW, but instead usage fully compensated under the HB 1777 regime. Therefore, municipalities will experience no fiscal impact because the concept of full compensation indicates revenue neutrality.

The commission disagrees with Leon Valley's argument that the retained right of cities to initiate legal action is hardly a useful right. Municipal police powers are of paramount benefit to its citizens. The commission notes that the Legislature recognizes the value of a municipality's legal action options. Otherwise, the Legislature would not have expressly retained that power to the municipalities in §283.051. The commission asserts that public ROW is public property, not private property, and that no citizens are experiencing any taking of public property by private entities in this situation, as all CTP usage of ROW for access lines is fully compensated under the access line compensation regime. There is no, nor should there be, double financial burden on citizens.

The commission disagrees with TCCFUI's position in its letter of March 19, 2001 and with Plano's assertion that the construction of lines that pass through the public ROW affects the commission's statement of revenue neutrality. The commission maintains that there will be no effect on local economy or local employment as a result of the rule amendment. The fiscal impact of pass-through lines rests on the expectation of a municipality for a revenue amount rather than on a true impact to that amount. The proposed amendment does not alter a provider's choice as to where infrastructure should be placed. Therefore, this rulemaking will have no impact on the local economy.

The commission maintains that the notice published in the April 6, 2001 issue of the *Texas Register* complied with Texas Government Code §2001.024(a)(4)(A). In compliance, the preamble to the proposed rule amendments stated that staff " . . . determined that for each year of the first five-year period the proposed amendment and proposed new section are in effect, there will be no fiscal implications for the state as a result of enforcing or administering the sections. Because there are at least 1100 diverse municipalities in Texas, fiscal implications may vary. However, because these proposed rules do not alter a municipality's option to exercise its police power-based regulations in accordance with Texas Local Government Code §283.056(c), there should be no fiscal impact on any given municipality. In addition, because Texas Local Government Code §283.051(b) provides that municipalities continue to have the right to initiate legal action against CTPs, there is no fiscal implication regarding remedies available to municipalities."

TCCFUI's suggestion that there will be major costs of litigating the validity of the new rule is misplaced. TCCFUI's comment implied that Texas Government Code §2001.002 requires an analysis of the probability of lawsuits regarding the validity of every rule proposed in the State of Texas because lawsuits affect the local economy. The commission believes that it adopts only valid rules. In this particular instance, the adopted rule amendment follows the text of the statute and is therefore certainly a valid interpretation. Texas Government Code §2001.022 requires the commission to determine the affect a proposed rule will have on the local economy rather than the affect of potential resulting litigation. The possibility that a municipality, person, or entity may challenge the validity of a rule by means of litigation is beyond the speculative scope of the commission. The commission believes that the proposed rule amendment follows and clarifies provisions of the statute, thereby fairly reducing uncertainty and litigation concerning franchise fees in accordance with the stated purpose in Texas Local Government Code §283.001(a)(4). Further, the commission observes that neither HB 1777 nor the proposed rule amendment modifies the stakeholders' option of litigious remedies. Texas Local Government Code §283.051(b) expressly provides that the right of a municipality to initiate legal action against a CTP is not affected. Now, as before the existence of HB 1777, municipalities retain their option to initiate suit against a provider. The commission's proposed rule amendment exercises no control over a municipality's decision to initiate litigation.

In fulfillment of the Texas Government Code §2001.022 requirements, the commission determined that the proposed rule amendment would have no affect on the local economy. Therefore, no local employment impact statement was required of the Texas Employment Commission (now the Texas Workforce Commission). The commission notes that House Bill 1872 of the 77th Texas Legislature, Regular Session (2001) becomes effective September 1, 2001 making the determination the responsibility of each state agency before rule adoption. Therefore, in an abundance of caution, the commission again makes its determination that the proposed amendment and adopted rule do not affect the local economy or employment.

The commission declines to modify the rule amendment in response to TCCFUI's unofficial comment concerns or to official comments.

All written and oral comments, including any not specifically referenced herein, were fully considered by the commission.

This amendment is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2001) (PURA), which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction. The amendment is also adopted under Texas Local Government Code §283.058, which grants the commission jurisdiction over municipalities and CTPs necessary to enforce the provisions of Chapter 283.

Cross Reference to Statutes: Public Utility Regulatory Act §14.002 and §14.052 and Texas Local Government Code §283.058.

*§26.465. Methodology for Counting Access Lines and Reporting Requirements for Certificated Telecommunications Providers.*

(a) Purpose. This section establishes a uniform method for counting access lines within a municipality by category as provided by §26.461 of this title (relating to Access Line Categories), sets forth relevant reporting requirements, and sets forth certain reseller obligations under the Local Government Code, Chapter 283.

(b) Application. This section applies to all certificated telecommunications providers (CTPs) in the State of Texas.

(c) Definitions. The following words and terms when used in this section, shall have the following meaning, unless the context clearly indicates otherwise.

(1) Customer - The retail end-use customer.

(2) Transmission path - A path within the transmission media that allows the delivery of switched local exchange service.

(A) Each individual circuit-switched service shall constitute a single transmission path.

(B) Where services are offered as part of a bundled group of services, each switched service in that bundled group of services shall constitute a single transmission path.

(C) Only those services that require the use of a circuit-switch shall constitute a switched service.

(D) Services that constitute vertical features of a switched service, such as call waiting, caller-ID, etc., that do not require a separate switched path, do not constitute a transmission path.

(E) Where a service or technology is channelized by the CTP and results in a separate switched path for each channel, each such channel shall constitute a single transmission path.

(3) Wireless provider - A provider of commercial mobile service as defined by §332(d), Communications Act of 1934 (47 U.S.C. §151 *et seq.*), Federal Communications Commission rules, and the Omnibus Budget Reconciliation Act of 1993 (Public Law 103-66).

(d) Methodology for counting access lines. A CTP's access line count shall be the sum of all lines counted pursuant to paragraphs (1), (2), and (3) of this subsection, and shall be consistent with subsections (e), (f) and (g) of this section.

(1) Switched transmission paths and services.

(A) The CTP shall determine the total number of switched transmission paths, and shall take into account the number of switched services provided and the number of channels used where a service or technology is channelized.

(B) All switched services shall be counted in the same manner regardless of the type of transmission media used to provide the service.

(C) If the transmission path crosses more than one municipality, the line shall be counted in, and attributed to, the municipality where the end-use customer is located. Pursuant to Local Government Code §283.056(f), the per-access-line franchise fee paid by CTPs constitutes full compensation to a municipality for all of a CTP's facilities located within a public right-of-way, including interoffice transport and other transmission media that do not terminate at an end-use customer's premises, even though those types of lines are not used in the calculation of the compensation.

(2) Nonswitched telecommunications services or private lines.

(A) Each circuit used to provide nonswitched telecommunications services or private lines to an end-use customer, shall be considered to have two termination points, one on each customer location identified by the customer and served by the circuit.

(B) The CTP shall count nonswitched telecommunications services or private lines by totaling the number of terminating points within a municipality.

(C) A nonswitched telecommunications service shall be counted in the same manner regardless of the type of transmission media used to provide that service.

(D) A terminating point shall be counted in, and attributed to, the municipality where that point is located. In the event a CTP is not able to identify the physical location of the terminating point, that point shall be attributed to the municipality identified by the CTP's billing systems.

(E) Where dark (unlit) fiber is provided to an end-use customer who then lights it, the line shall be counted as a private line, by default, unless it is evident that it is used for providing switched services.

(3) Central office based PBX-type services. The CTP shall count one access line for every ten stations served.

(e) Lines to be counted. A CTP shall count the following access lines:

(1) all access lines provided to a retail end-use customer;

(2) all access lines provided as a retail service to other CTPs and resellers for their own end-use;

(3) all access lines provided as a retail service to wireless telecommunication providers and interexchange carriers (IXCs) for their own end-use;

(4) all access lines a CTP provides as employee concession lines and other similar types of lines;

(5) all access lines provided as a retail service to a CTP's wireless and IXC affiliates for their own end-use, and all access lines provided as a retail service to any other affiliate for their own end-use;

(6) dark fiber, to the extent it is provided as a service or is resold by a CTP and shall exclude lines sold and resold by non-CTPs;

(7) any other lines meeting the definition of access line as set forth in §26.461 of this title; and

(8) Lifeline and Tel-assistance lines.

(f) Lines not to be counted. A CTP shall not count the following lines:

(1) all lines that do not terminate at an end-use customer's premises;

(2) lines used by providers who are not end-use customers such as CTP, wireless provider, or IXC for interoffice transport, or back-haul facilities used to connect such providers' telecommunications equipment;

(3) lines used by a CTP's wireless and IXC affiliates who are not end-use customers, for interoffice transport, or back-haul facilities used to connect such affiliates' telecommunications equipment;

(4) lines used by any other affiliate of a CTP for interoffice transport; and

(5) any other lines that do not meet the definition of access line as set forth in §26.461 of this title.

(g) Reporting procedures and requirements.

(1) Who shall file. The record keeping, reporting and filing requirements listed in this section shall apply to all CTPs in the State of Texas.

(2) Reporting requirements. Unless otherwise specified, periodic reporting shall be consistent with this subsection and subsection (d) of this section.

(A) Initial reporting.

*(i)* No later than January 24, 2000, a CTP shall file its access line count using the commission-approved *Form for Counting Access Line or Program for Counting Access Lines* with the commission. The CTP shall report the access line count as of December 31, 1998, except as provided in clause (iii) of this subparagraph.

*(ii)* A CTP shall not include in its initial report any access lines that are resold, leased, or otherwise provided to a CTP, unless it has agreed to a request from another CTP to include resold or leased lines as part of its access line report.

*(iii)* A CTP that cannot file access line count as of December 31, 1998 shall file request for good cause exemption and shall file the most recent access line count available for December, 1999.

*(iv)* A CTP shall not make a distinction between facilities and capacity leased or resold in reporting its access line count.

(B) Subsequent reporting.

*(i)* Each CTP shall file with the commission a quarterly report beginning the second quarter of the year 2000, showing the number of access lines, including access lines by category, that the CTP has within each municipality at the end of each month of the quarter. The report shall be filed no later than 45 days after the end of the quarter using the commission-approved Form for Quarterly Reporting of Access Lines and shall coincide with the payment to a municipality.

*(ii)* The first report shall be due to the commission no later than August 15, 2000 and shall include access line for the second calendar quarter of 2000 and shall coincide with the first payment to a municipality pursuant to the Local Government Code, Chapter 283.

*(iii)* Except as provided in clause (iv) of this subparagraph, on request of the commission, and to the extent available, the report filed under clause (i) of this subparagraph shall identify, as part of the CTP's monthly access line count, the access lines that are provided by means of resold services or unbundled facilities to another CTP who is not an end- use customer, and the identity of the CTPs obtaining the resold services or unbundled facilities to provide services to customers.

*(iv)* A CTP may not include in its monthly count of access lines any access lines that are resold, leased, or otherwise provided to another CTP if the CTP receives adequate proof that the CTP leasing or purchasing the access lines will include the access lines in its own monthly count. Adequate proof shall consist of a notarized statement prepared consistent with subsection (k) of this section.

*(v)* The CTP shall respond to any request for additional information from the commission within 30 days from receipt of the request.

*(vi)* Reports required under this subsection may be used by the commission only to verify the number of access lines that serve customer premises within a municipality.

*(vii)* On request from a municipality, and subject to the confidentiality protections of subsection (j) of this section, each CTP shall provide each affected municipality with a copy of the municipality's access line count.

(h) Exemption. Any CTP that does not terminate a franchise agreement or obligation under an existing ordinance shall be exempted from subsequent reporting pursuant to subsection (g)(2)(B) of this section unless and until the franchise agreement is terminated or expires on its own terms. Any CTP that fails to provide notice to the commission and the affected municipality by December 1, 1999 that it elects to terminate its franchise agreement or obligation under an existing ordinance, shall be deemed to continue under the terms of the existing ordinance. Upon expiration or termination of the existing franchise agreement or ordinance by its own terms, a CTP is subject to the terms of this section.

(i) Maintenance and location of records. A CTP shall maintain all records, books, accounts, or memoranda relating to access lines deployed in a municipality in a manner which allows for easy identification and review by the commission and, as appropriate, by the relevant municipality. The books and records for each access line count shall be maintained for a period of no less than three years.

(j) Proprietary or confidential information.

(1) The CTP shall file with the commission the information required by this section regardless of whether this information is confidential. For information that the CTP alleges is confidential and/or proprietary under law, the CTP shall file a complete list of the information that the CTP alleges is confidential. For each document or portion thereof claimed to be confidential, the CTP shall cite the specific provision(s) of the Texas Government Code, Chapter 552, that the CTP relies to assert that the information is exempt from public disclosure. The commission shall treat as confidential the specific information identified by the CTP as confidential until such time as a determination is made by the commission, the Attorney General, or a court of competent jurisdiction that the information is not entitled to confidential treatment.

(2) The commission shall maintain the confidentiality of the information provided by CTPs, in accordance with the Public Utility Regulatory Act (PURA) §52.207.

(3) If the CTP does not claim confidential treatment for a document or portions thereof, then the information will be treated as public information. A claim of confidentiality by a CTP does not bind the commission to find that any information is proprietary and/or confidential under law, or alter the burden of proof on that issue.

(4) Information provided to municipalities under the Local Government Code, Chapter 283, shall be governed by existing confidentiality procedures which have been established by the commission in compliance with PURA §52.207.

(5) The commission shall notify a CTP that claims its filing as confidential of any request for such information.

(k) Report attestation. All filings with the commission pursuant to this section shall be in accordance with §22.71 of this title (relating to Filing of Pleadings, Documents and Other Materials) and §22.72 of this title (relating to Formal Requisites of Pleadings and Documents to Be Filed With the Commission). The filings shall be attested to by an officer or authorized representative of the CTP under whose direction the report is prepared or other official in responsible charge of the entity in accordance with §26.71(d) of this title (relating to General Procedures, Requirements and Penalties). The filings shall include a certified statement from an authorized officer or duly authorized representative of the CTP stating that the information contained in the report is true and correct to the best of the officer's or representative's knowledge and belief after inquiry.

(l) Reporting of access lines that have been provided by means of resold services or unbundled facilities to another CTP. This subsection applies only to a CTP reporting access lines under subsection (g) of this section, that are provided by means of resold services or unbundled facilities to another CTP who is not an end-use customer. Nothing in this subsection shall prevent a CTP reporting another CTP's access line count from charging an appropriate, tariffed administrative fee for such service.

(m) Commission review of the definition of access line.

(1) Pursuant to the Local Government Code §283.003, not later than September 1, 2002, the commission shall determine whether changes in technology, facilities, or competitive or market conditions justify a modification of the adoption of the definition of "access line" provided by §26.461 of this title. The commission may not begin a review authorized by this subsection before March 1, 2002.

(2) As part of the proceeding described by paragraph (1) of this subsection, and as necessary after that proceeding, the commission by rule may modify the definition of "access line" as necessary to ensure competitive neutrality and nondiscriminatory application and to maintain consistent levels of compensation, as annually increased by growth in access lines within the municipalities.

(3) After September 1, 2002, the commission, on its own motion, shall make the determination required by this subsection at least once every three years.

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 September 25, 2001.

TRD-200105801
Rhonda G. Dempsey
Rules Coordinator
Public Utility Commission of Texas
Effective date: October 15, 2001
Proposal publication date: April 6, 2001
For further information, please call: (512) 936-7308

♦ ♦ ♦

# PART 4. TEXAS DEPARTMENT OF LICENSING AND REGULATION

## CHAPTER 80. LICENSED COURT INTERPRETERS

### 16 TAC §§80.1, 80.10, 80.20, 80.22, 80.24, 80.70, 80.80, 80.90

The Texas Department of Licensing and Regulation adopts new §§80.1, 80.10, 80.20, 80.22, 80.24, 80.70, 80.80, and 80.90 concerning the licensing and regulation of court interpreters for individuals who do not communicate in English. Sections 80.1, 80.10, 80.20, 80.22, 80.24, 80.80, and 80.90 are adopted without changes as published in the August 3, 2001 issue of the *Texas Register* (26 TexReg 5738) and will not be republished. Section 80.70 is adopted with changes to the proposed text as published in the August 3, 2001 issue of the *Texas Register* (26 TexReg 5738).

Section 80.70(c) as proposed required a licensee to notify the department of any change in the information in the licensee's application. The version of §80.70(c) to be adopted requires the licensee to notify the department of any change in the licensee's name, address, or telephone number. This change was made because the Department determined that notification of any other changes in the information in a licensee's application would not be needed.

The adopted rules are to implement the provisions of House Bill 2735, enacted by the 77th Texas Legislature. House Bill 2735 establishes Chapter 57 of the Texas Government Code regarding court interpreters. The court interpreter program will be a new program for the State of Texas, which has not regulated court interpreters in the past.

Subchapter C of Chapter 57 grants the Department authority to license and regulate court interpreters for individuals who do not communicate in English. Subchapter C took effect September 1, 2001, except for §57.049 and §57.050, which will take effect January 1, 2002 and relate to prohibited acts, offenses, and administrative penalties.

The Department drafted and distributed the proposed rules to persons internal and external to the agency, held a focus group meeting concerning the rules on June 29, 2001, met with representatives of the Bexar County Justice Center on July 5, 2001, met with State Court Administrators on July 23, 2001, met with Travis County Municipal Court Judge Evelyn McKee on August 22, 2001, and has received written comments for and against the proposed rules.

The Department wishes to thank all of the persons and organizations who participated in its rulemaking process and submitted comments on the proposed rules. The following discussion summarizes the comments received by the Department, identifies who made the comments, and responds to the comments.

*Comment on proposed rule §80.24*: The Department should not license persons as court interpreters in Texas unless they have passed a Department, federal, or state court-interpreter examination, or unless they are required to pass an examination in the future as a condition of maintaining their license.

This comment or portions of this comment were received from most persons submitting comments, including the Bexar County Justice Center.

*Response to comment*: Disagree.

First, there is the issue of legislative intent and the plain meaning of the language used in House Bill 2735. Section 5 of House Bill 2735 specifically provides that a person practicing as a court interpreter before September 1, 2001 ("practicing court interpreters") may be licensed without examination by submitting proof of experience on an application filed with the Department not later than January 1, 2002. The Department interprets §5 as granting a right to practicing court interpreters to become licensed without examination if they can demonstrate to the Executive Director that they have experience as court interpreters.

Section 80.24(a) of the proposed rules enacts the legislative intent of House Bill 2735 by allowing the Executive Director to issue court interpreter licenses to persons who file their application by January 1, 2002 and who show "acceptable proof" of their experience. "Acceptable proof" is defined in subsection 80.24(b) of the proposed rules to include a written reference from an officer of the court, the results of an examination passed within the preceding two years, or other proof the Executive Director may deem appropriate.

The Department interprets the statutory term "without examination" in House Bill 2735 to refer to any type of examination of court interpreters, whether the examination is administered by the Department or by the federal government or another state. There is nothing in the statute that limits the meaning of "examination" to only those examinations administered by the Department.

Similarly, there is nothing in the statute that indicates that the Legislature wanted to restrict the type of license issued to persons who file their applications on or before January 1, 2002 and who do not take an examination as a condition of licensure. No mention is made in the statute of provisional licenses, contingent licenses, or any other type of limited license. The Department interprets House Bill 2735 as mandating the issuance of full licenses to such persons.

In addition to legislative intent, there also are important policy considerations which support §80.24 as proposed, which are listed below.

(1) Section 80.24 provides greater protection for the public than currently exists. By allowing the Executive Director to examine proof of experience as a condition of licensure, the Department can begin regulating the qualifications and competence of practicing court interpreters for the first time in Texas.

(2)The Department should begin evaluating the qualifications of practicing court interpreters as soon as possible. Requiring the Department to develop and administer examinations before undertaking these evaluations would substantially delay the evaluations and the implementation of the new license program.

(3) The sooner that the licensing program is implemented, the sooner that the public can be protected by the Department's Enforcement Program. This would include protections such as reprimand, suspension, or revocation of a court interpreter's license, the assessment of administrative penalties, agreed orders which address consumers' concerns, injunctive relief, and civil penalties.

(4) The Department should implement the court interpreter program in such a way that it does not interrupt litigation in courts. The Department anticipates that implementation of examinations could take several months, into the year 2002. Therefore, it believes that a requirement that court interpreters must first take an examination before they can continue practicing in 2002 could cause significant delays in litigation in 2002, and should be avoided.

(5) The Department believes that it may reasonably rely on the observations and opinions of active judges, attorneys, and other professionals who have had direct personal experience with the applicants' court interpreting services. The Department believes that it should give substantial weight to the observations and opinions of these persons in making its licensing decisions.

*Comment on proposed rule §80.24*: The Department should give effect to the legislative intent of House Bill 2735, should allow persons to be licensed without examination if they file an application and proof of experience by January 1, 2002, and should not require examinations for them because this would create a shortage of court interpreters in Texas courts.

*Response to comment*: Agree.

*Comment on proposed rule §80.24*: Forcing persons filing an application for a court interpreter license after January 1, 2002 to pass an examination would subject non-English speakers to unfair interpretations because many of these non-English speakers do not speak the "proper" language.

*Response to comment*: Disagree.

There is no evidence to indicate that a person who passes a court-interpreter examination will be less qualified than a person who does not pass the examination to interpret the proper form of a language or other forms of the language. To the contrary, the examination requirement will help ensure that an interpreter can interpret speakers who speak the proper form of a language as well as those who do not.

*Comment on proposed rule §80.24*: The new rules should include a definition of "grandfathering" since this term was used in discussions on the proposed rules.

*Response to comment*: Disagree.

The Department has not included the term "grandfathering" in the rules because the concept to which it refers is already clearly expressed in the rules. That is, "grandfathering" refers to allowing persons already practicing as court interpreters to continue working as court interpreters without having to meet additional substantive requirements, such as examination, that were not in effect at the time they became court interpreters. The grandfathering concept recognizes the industry as it exists by not displacing those persons already established as court interpreters, thereby making a smoother transition to the Department's regulation of the industry.

*Comment on proposed rule §80.24*: The Bexar County Justice Center commented that interpreters should be required to prove that they have 200 hours of court interpreting experience within the preceding two years before they can be licensed without an examination.

*Response to comment*: Disagree.

The Department does not believe that it should require a specific number of hours of court interpreting experience before a person can be licensed under proposed rule §80.24, as it has no basis yet for setting this requirement at 200 hours or any other number of hours. Rather than set an experience requirement on an arbitrary basis, the Department believes that it should evaluate each applicant's experience on a case-by-case basis.

*Comment on proposed rule §80.24*: Requirements for English-Spanish speakers should include a minimum of five years of experience, a written reference exclusively from a state district judge, and at least 40 hours of trial interpretation in civil and criminal cases validated by a district or county judge.

*Response to comment*: Disagree.

The Department does not believe that it should require a specific number of years or hours of court interpreting experience before a person can be licensed under proposed rule §80.24, as it has no basis yet for setting this requirement at five years, 40 hours, or any other number of years or hours. Rather than set an experience requirement on an arbitrary basis, the Department believes that it should evaluate each applicant's experience on a case-by-case basis.

The Department also does not think it should limit professional references to only those received from state district judges. The Department believes that references received from federal judges, state county judges, judges in other countries, hearing officers, attorneys, and other professionals who have direct personal knowledge of an applicant's abilities also should be considered in making its licensing decisions.

*Comment on proposed rules §80.10(2) and (4): The Bexar County Justice Center commented that the rules should include a code of ethics.*

*Response to comment*: Disagree.

The statute and the proposed rules provide for penalties and sanctions for dishonorable and unethical conduct. A more comprehensive code of ethics will need the input of the Licensed Court Interpreter Advisory Board, the members of which have yet to be appointed.

*Comment on proposed rule §80.22*: The Bexar County Justice Center commented that a license to interpret certain uncommon languages should not be required.

*Response to comment*: Disagree.

House Bill 2735 does not give the Department the authority to exempt the interpretation of particular languages from the license requirements.

*Comment on proposed rule §80.22*: Examination fees should be based on language pairs. Language pairs are the language being interpreted from and the language being interpreted into.

*Response to comment*: Agree.

The examinations will test both English and the non-English language that the applicant chooses for his or her endorsement. The examination fee will cover both components of the examination.

*Comment of proposed rule 80.22*: Examinations should include a section on ethics.

*Response to comment: Disagree.*

The statute and the proposed rules provide for penalties and sanctions for dishonorable and unethical conduct. A more comprehensive code of ethics will need the input of the Licensed Court Interpreter Advisory Board, the members of which have yet to be appointed.

*Comment on the rules in general*: The rules should require continuing education as a condition of license renewal.

*Response to comment*: Disagree.

House Bill 2735 does not authorize the Department to require continuing education as a condition of license renewal.

*Comment on the rules in general*: The Department's rules should appear in the Texas Rules of Civil Procedure.

*Response to comment*: Disagree.

Neither House Bill 2735 nor any other statute grants authority to the Department to promulgate Texas Rules of Civil Procedure.

*Comment on the rules in general*: The Department should require a licensed court interpreter to be present throughout the judicial process, including interviews, discovery, pre-trial meetings, jury selection, and trial.

*Response to comment*: Disagree.

House Bill 2735 only mandates the appointment of a licensed court interpreter upon the motion of a party or the request of the witness who desires interpretation. The Department does not have the authority to require persons to be licensed if they perform court interpreting services when such motions or requests have not been made.

*Comment on the rules in general*: The Department should guarantee a revenue increase to interpreters who obtains a license.

*Response to comment*: Disagree.

House Bill 2735 does not give the Department authority to guarantee revenue increases for license holders.

The new rules are adopted under House Bill 2735, enacted by the 77th Texas Legislature in 2001, which establishes Chapter 57 (Court Interpreters), Subtitle D, Title 2, Texas Government Code, and provides the Texas Department of Licensing and Regulation the authority to promulgate and enforce rules and to take action necessary to assure compliance with the intent and purpose of the Act.

The statutory provisions affected by the new rules are those set forth in Chapter 57 of the Texas Government Code and Chapter 51 of the Texas Occupations Code.

*§80.70. Responsibilities of Licensee - General.*

(a) A licensee must provide the following written notification to the court: "Regulated by The Texas Department of Licensing and Regulation, P.O. Box 12157, Austin, Texas 78711, 1-800-803-9202, 512-463-6599." The notification shall also be included on all contracts and invoices for court interpreter services.

(b) A licensee shall present their court interpreter license upon the request of a court or an officer of the court.

(c) A licensee shall notify the Department, in writing, within thirty (30) days of any change in the licensee's name, address, or telephone number.

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 September 28, 2001.

TRD-200105879
William H. Kuntz, Jr.
Executive Director
Texas Department of Licensing and Regulation
Effective date: October 18, 2001
Proposal publication date: August 3, 2001
For further information, please call: (512) 463-7348

♦ ♦ ♦

# TITLE 22. EXAMINING BOARDS

## PART 3. TEXAS BOARD OF CHIROPRACTIC EXAMINERS

### CHAPTER 73. LICENSES AND RENEWALS

#### 22 TAC §73.2

The Texas Board of Chiropractic Examiners adopts an amendment to §73.2(a), relating to renewal of license, without changes to the proposed text as published in the June 15, 2001, issue of the *Texas Register* (26 TexReg 4366) and will not be republished.

By separate rulemaking in the July 27, 2001, issue of the *Texas Register* (26 TexReg 5639), the board adopted an amendment to §75.7, to accept personal or company checks for payment of fees. The adopted amendment to §75.7 permits the use of a personal or company check, money order, cashier or certified check. To discourage checks drawn on insufficient funds, the board is also establishing a fee for a returned check in the amount of $25. The adopted amendment also sets out procedures and requirements for processing an application for which a check has been returned. In conjunction with this rulemaking, the board adopted amendments to §73.2(a), 71.2(b), and 78.1, for consistency and conformity with the adopted amendments to §75.7. By this rulemaking, the board deleted provisions in subsection (a) of §73.2 that are covered in the amended §75.7. See also the separate adopted rulemakings published in the July 27, 2001, issue of the *Texas Register* (26 TexReg 5639).

No comments were received regarding adoption of the amendment.

The amendment is adopted under the Occupations Code, §201.152, which the board interprets as authorizing it to adopt rules necessary for the performance of its duties, the regulation of the practice of chiropractic, and the enforcement of the act, and §201.153, which the board interprets as authorizing it to adopt necessary fees for administration of its programs.

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 October 1, 2001.

TRD-200105906
Gary K. Cain, Ed.D.
Executive Director
Texas Board of Chiropractic Examiners
Effective date: October 21, 2001
Proposal publication date: June 15, 2001
For further information, please call: (512) 305-6709

♦ ♦ ♦

### CHAPTER 74. CHIROPRACTIC FACILITIES

#### 22 TAC §§74.1 - 74.3, 74.5

The Texas Board of Chiropractic Examiners adopts an amendment to Chapter 74, §§74.1 - 74.3 and §74.5, relating to chiropractic facilities, without changes to the proposed text as published in the July 27, 2001, issue of the *Texas Register* (26 TexReg 5567) and will not be republished.

This year, the 77th Legislature passed Senate Bill 145, effective September 1, 2001, amending the Chiropractic Act, Occupations Code §201.312(b), to require an owner of a chiropractic facility to pay a license fee for each place of business. Currently §201.312(b) requires one license and one fee for each facility regardless of the number of facilities owned by a person. The adopted amendments to §74.2 conform the section to this change in law. Applications submitted on or after September 1 for the upcoming year will be processed under the new §201.312(b). Additional amendments were also made to §§74.1 - 74.3 and §74.5 for clarification, consistency with other board rules, and to remove redundant provisions.

No comments were received regarding adoption of the rules.

The amendments are adopted under the Occupations Code, §201.152, which the board interprets as authorizing it to adopt rules necessary for the performance of its duties, the regulation of the practice of chiropractic, and the enforcement of the Chiropractic Act, §201.153, which the board interprets as authorizing it to adopt rules providing fees reasonable and necessary to administer its regulatory program under Chapter 201, and §201.312, which the board interprets as authorizing it to adopt rules providing for licensure for chiropractic facilities.

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 October 1, 2001.

TRD-200105907
Gary K. Cain, Ed.D.
Executive Director
Texas Board of Chiropractic Examiners
Effective date: October 21, 2001
Proposal publication date: July 27, 2001
For further information, please call: (512) 305-6709

♦ ♦ ♦

## PART 9. TEXAS STATE BOARD OF MEDICAL EXAMINERS

### CHAPTER 161. GENERAL PROVISIONS

#### 22 TAC §161.1

The Texas State Board of Medical Examiners adopts an amendment to §161.1, concerning general provisions, without changes to the proposed text as published in the July 20, 2001, issue of the *Texas Register* (26 TexReg 5333).

The amendment will update the Occupations Code cites and clarify responsibilities of certain board committees.

No comments were received regarding adoption of the proposal.

The amendment is adopted under the authority of the Occupations Code Annotated, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §§152.009, 153.005, and 162.001 are affected by the amendment.

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 September 27, 2001.

TRD-200105859
Donald W. Patrick MD, JD
Executive Director
Texas State Board of Medical Examiners
Effective date: October 17, 2001
Proposal publication date: July 20, 2001
For further information, please call: (512) 305-7016

♦ ♦ ♦

## CHAPTER 163. LICENSURE

### 22 TAC §§163.1, 163.9, 163.10

The Texas State Board of Medical Examiners adopts amendments to §§163.1, 163.9, and 163.10, concerning licensure, without changes to the proposed text as published in the July 20, 2001, issue of the *Texas Register* (26 TexReg 5336).

The proposal will update Occupation Code cites and clarify requirements relating to relicensure.

No comments were received regarding adoption of the proposal.

The amendments are adopted under the authority of the Occupations Code Annotated, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §§152.002, 155.051, 156.005, 156.006, and 164.051 are affected by the amendments.

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 September 27, 2001.

TRD-200105860
Donald W. Patrick, MD, JD
Executive Director
Texas State Board of Medical Examiners
Effective date: October 17, 2001
Proposal publication date: July 20, 2001
For further information, please call: (512) 305-7016

♦ ♦ ♦

## CHAPTER 166. PHYSICIAN REGISTRATION

### 22 TAC §§166.2 - 166.4, 166.6

The Texas State Board of Medical Examiners adopts amendments to §§166.2-166.4, and 166.6, concerning physician registration, without changes to the proposed text as published in the July 20, 2001, issue of the *Texas Register* (26 TexReg 5339).

The proposal will update Occupation Code cites and clarify which board committee is responsible for considering a physician's request to return to active status from retired status.

No comments were received regarding adoption of the proposal.

The amendments are adopted under the authority of the Occupations Code Annotated, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §§156.001, 156.002, 156.003, 156.004, 156.005, 156.006, 156.007, 156.008, 156.009, 156.051, 156.052, 156.053, 156.054, 156.055, 164.051, 164.052, and 164.053 are affected by the amendments.

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 September 27, 2001.

TRD-200105861
Donald W. Patrick, MD, JD
Executive Director
Texas State Board of Medical Examiners
Effective date: October 17, 2001
Proposal publication date: July 20, 2001
For further information, please call: (512) 305-7016

♦ ♦ ♦

## CHAPTER 167. REINSTATEMENT AND REISSUANCE

The Texas State Board of Medical Examiners adopts amendments to §§167.1, 167.2-167.8, the repeal and new of §167.3, concerning reinstatement, without changes to the proposed text as published in the July 20, 2001, issue of the *Texas Register* (26 TexReg 5342).

The proposal will update Occupation Code cites and clarify criteria to be considered when determining whether or not to reinstate a medical license following suspension or to reissue a license following revocation.

No comments were received regarding adoption of the proposal.

### 22 TAC §§167.1 - 167.8

The amendments are adopted under the authority of the Occupations Code Annotated, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §§164.003, 164.007, 164.009, 164.101, 164.102, 164.151, 164.152, 164.153, and 164.154 are affected by the amendments.

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 September 27, 2001.

TRD-200105862
Donald W. Patrick, MD, JD
Executive Director
Texas State Board of Medical Examiners
Effective date: October 17, 2001
Proposal publication date: July 20, 2001
For further information, please call: (512) 305-7016

♦ ♦ ♦

**22 TAC §167.3**

The repeal is adopted under the authority of the Occupations Code Annotated, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §§164.003, 164.007, 164.009, 164.101, 164.102, 164.151, 164.152, 164.153, and 164.154 are affected by the repeal.

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 September 27, 2001.

TRD-200105863
Donald W. Patrick, MD, JD
Executive Director
Texas State Board of Medical Examiners
Effective date: October 17, 2001
Proposal publication date: July 20, 2001
For further information, please call: (512) 305-7016

♦ ♦ ♦

# PART 23. TEXAS REAL ESTATE COMMISSION

## CHAPTER 535. PROVISIONS OF THE REAL ESTATE LICENSE ACT

## SUBCHAPTER E. REQUIREMENTS FOR LICENSURE

**22 TAC §535.51**

The Texas Real Estate Commission (TREC) adopts an amendment to §535.51, concerning general requirements for a real estate license, with changes to the proposed text as published in the June 29, 2001, issue of the *Texas Register*(26 TexReg 4822).

Adoption of the amendment is necessary to make the section consistent with House Bill 695, 77th Legislature (2001), which modified the process by which a person becomes licensed as a real estate salesperson. Effective September 1, 2001, House Bill 695 requires a person to file an application for an inactive salesperson license, and a sponsoring broker will not be applying for the license with the salesperson. Before an inactive salesperson may practice real estate brokerage, however, the salesperson must be sponsored by an active real estate broker. The amendment to §535.51 deletes language in the section referring to a sponsoring broker and adopts revised forms used by applicants to obtain an initial salesperson license, to obtain another salesperson license after expiration of a prior license, or to obtain a salesperson license after being previously licensed as a real estate broker. The forms have been revised to reflect the statutory change in procedure regarding sponsorship by a broker. Minor changes also have been made in the forms to make them easier to read and to eliminate unnecessary questions.

No public comments were received regarding the proposal, but TREC staff suggested changes to §535.51 to clarify how online applications are made. The staff suggested that if an individual applicant has provided a photograph and signature, it would not be necessary for the applicant also to file a hard copy of the application after submitting the application online. The commission determined that since the primary purpose of filing the hard copy was for TREC to obtain a photograph and signature for the applicant, the section should be modified as suggested. Language also was added to clarify the photograph and signature of the applicant could be provided before the application for a license is filed, such as when the applicant requests an educational evaluation.

The amendment is adopted under Texas Civil Statutes, Article 6573a, §5(h), which authorizes the Texas Real Estate Commission to make and enforce all rules and regulations necessary for the performance of its duties.

*§535.51. General Requirements.*

(a) A person who wishes to be licensed by the commission must file an application for the license on the form adopted by the commission for that purpose. Prior to filing the application, the applicant must pay the required fee for evaluation of the education completed by the person and must obtain a written response from the commission showing the applicant meets current education requirements for the license.

(b) If the commission develops a system whereby a person may electronically file an application for a license, a person who has previously satisfied applicable education requirements and obtained an evaluation from the commission also may apply for a license by accessing the commission's Internet web site, entering the required information on the application form and paying the appropriate fee in accordance with the instructions provided at the site by the commission. If the person is an individual, the person must provide the commission with the person's photograph and signature prior to issuance of a license certificate. The person may provide the photograph and signature prior to the submission of an electronic application.

(c) The commission shall return applications to applicants when it has been determined that the application fails to comply with one of the following requirements.

(1) The applicant is not 18 years of age.

(2) The applicant does not meet any applicable residency requirement.

(3) An incorrect filing fee or no filing fee is received.

(4) The application is submitted in pencil.

(5) The applicant is not a citizen of the United States or a lawfully admitted alien.

(6) The applicant has not obtained an evaluation from the commission showing the applicant meets education requirements or experience requirements have not been satisfied.

(d) An application is considered void and is subject to no further evaluation or processing when one of the following events occurs:

(1) the applicant fails to satisfy an examination requirement within six months from the date the application is filed;

(2) the applicant, having satisfied any examination requirement, fails to submit a required fee within sixty (60) days after the commission makes written request for payment;

(3) the applicant, having satisfied any examination requirement, fails to provide information or documentation within sixty (60) days after the commission makes written request for correct or additional information or documentation.

(e) The commission adopts by reference the following forms approved by the commission which are published by and available from the Texas Real Estate Commission, P.O. Box 12188, Austin, Texas 78711-2188:

(1) Application for a Real Estate Broker License, TREC Form BL-6;

(2) Application for a Real Estate Broker License by a Corporation, TREC Form BLC-3;

(3) Application for Late Renewal of A Real Estate Broker License, TREC Form BLR-5;

(4) Application for Late Renewal of Real Estate Broker License Privileges by a Corporation, TREC Form BLRC-3

(5) Application for Real Estate Salesperson License, TREC Form SL-7 ;

(6) Application for Late Renewal of Real Estate Salesperson License, TREC Form SLR-6;

(7) Application for Moral Character Determination, TREC Form MCD-2;

(8) Application for Real Estate Broker License by a Limited Liability Company, TREC Form BLLLC-2;

(9) Application of Currently Licensed Real Estate Broker for Salesperson License, TREC Form BSL -3; and

(10) Application for Late Renewal of a Real Estate Broker License by a Limited Liability Company, TREC Form BLRLLC-1.

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 September 25, 2001.

TRD-200105791
Mark A. Moseley
General Counsel
Texas Real Estate Commission
Effective date: October 15, 2001
Proposal publication date: June 29, 2001
For further information, please call: (512) 465-3900

♦ ♦ ♦

## SUBCHAPTER F. EDUCATION, EXPERIENCE, EDUCATIONAL PROGRAMS, TIME PERIODS AND TYPE OF LICENSE

### 22 TAC §535.62

The Texas Real Estate Commission (TREC) adopts an amendment to §535.62, concerning acceptable courses of study, without changes to the proposed text as published in the August 3, 2001, issue of the *Texas Register* (26 TexReg 5739). Section 535.62 establishes the guidelines for TREC's acceptance of core real estate courses from license applicants. The amendment clarifies how the examination must be graded by the instructor or provider and permits the course provider to conduct the examination by use of a computer, thus allowing students to take the course examination online or at a site designated by the provider. Adoption of the amendment is necessary to permit correspondence course providers to employ the same examination alternatives that exist for providers who use alternative delivery systems, such as computers, for their courses. Students taking examinations by computer could avoid travel expense and delay in the completion of courses required to obtain a license from TREC.

No comments were received regarding the proposal.

The amendment is adopted under Texas Civil Statutes, Article 6573a, §5(h), which authorizes the Texas Real Estate Commission to make and enforce all rules and regulations necessary for the performance of its duties.

Filed with the Office of the Secretary of State on September 25, 2001.

TRD-200105795
Mark A. Moseley
General Counsel
Texas Real Estate Commission
Effective date: October 15, 2001
Proposal publication date: August 3, 2001
For further information, please call: (512) 463-3900

♦ ♦ ♦

## SUBCHAPTER G. MANDATORY CONTINUING EDUCATION

### 22 TAC §535.71, §535.72

The Texas Real Estate Commission (TREC) adopts amendments to §535.71, concerning approval of mandatory continuing education (MCE) providers, courses and instructors and §535.72, concerning presentation of courses, advertising and records, without changes to the proposed text as published in the August 3, 2001, issue of the *Texas Register* (26 TexReg 5740).

The amendment to §535.71 clarifies how a course examination must be graded by the instructor or provider and permits the course provider to conduct the examination by use of a computer, thus allowing students to take the course examination online or at a site designated by the provider. Adoption of the amendment also permits correspondence course providers to employ the same examination alternatives that exist for providers who use alternative delivery systems, such as computers. The amendment to §535.71 adopts by reference a revised form, MCE 9-4, Alternative Instructional Methods Reporting Form, which will be used by the provider to report the student's passing of the examination and successful completion of the course. The report form has been rearranged for clarity, and additional language has been added to emphasize the provider's obligation to submit the form to TREC. If the provider administers the examination on line, the section relating to the proctor would not be completed. The amendment to §535.72 updates a reference to the revised reporting form. Adoption of the amendments to §535.71 and to §535.72 is necessary to avoid confusion in the reporting of completion of correspondence courses and to clarify how to report course completion if the course examination is completed by computer. Adoption of the amendment to §535.71 also permits a student to avoid travel and possible delay in obtaining course credit if the course examination is administered online by computer.

No written comments were received regarding the proposal. The Texas Association of Realtors suggested at a meeting of the commission on July 16, 2001, that §535.72 should be amended to permit a provider to report course completion electronically, particularly when the course was being conducted online by the provider, rather than by filing a written report signed by the student. The commission generally supported the concept but determined that since the change had not been addressed in the published proposal, the appropriate response would be to propose the desired amendment after adoption of the original proposal.

The amendments are adopted under Texas Civil Statutes, Article 6573a, §5(h), which authorizes the Texas Real Estate Commission to make and enforce all rules and regulations necessary for the performance of its duties.

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 September 25, 2001.

TRD-200105792
Mark A. Moseley
General Counsel
Texas Real Estate Commission
Effective date: October 15, 2001
Proposal publication date: August 3, 2001
For further information, please call: (512) 465-3900

♦ ♦ ♦

## SUBCHAPTER J. FEES

### 22 TAC §535.101

The Texas Real Estate Commission (TREC) adopts an amendment to §535.101, concerning fees paid by real estate licensees and applicants, without changes to the proposed text as published in the June 29, 2001, issue of the *Texas Register* (26 TexReg 4824).

Adoption of the amendment is necessary to conform the section with H.B. 695, 77th Legislature (2001), increasing from $15 to $20 the fee TREC is required to charge for evaluation of a transcript. Section 535.101 has been amended to reflect the increased fee for requests for evaluations filed on or after September 1, 2001.

No comments were received regarding the proposal.

The amendment is adopted under Texas Civil Statutes, Article 6573a, §5(h), which authorizes the Texas Real Estate Commission to make and enforce all rules and regulations necessary for the performance of its duties.

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 September 25, 2001.

TRD-200105793
Mark A. Moseley
General Counsel
Texas Real Estate Commission
Effective date: October 15, 2001
Proposal publication date: June 29, 2001
For further information, please call: (512) 465-3900

♦ ♦ ♦

# TITLE 30. ENVIRONMENTAL QUALITY

# PART 1. TEXAS NATURAL RESOURCE CONSERVATION COMMISSION

## CHAPTER 7. MEMORANDA OF UNDERSTANDING

### 30 TAC §7.125

The Texas Natural Resource Conservation Commission (TNRCC or commission) adopts new §7.125, Memorandum of Understanding (MOU), among the Office of the Secretary of State (SOS), Railroad Commission of Texas (RRC), Texas Historical Commission (THC), Texas General Land Office (GLO), TNRCC, and Texas Public Utility Commission (PUC) regarding the permitting of natural gas pipelines that cross the border between Texas and Mexico. The SOS, RRC, THC, GLO, TNRCC, and PUC are collectively referred to as "the agencies." The proposal was published in the June 29, 2001 issue of the *Texas Register* (26 TexReg 4830). The new section is adopted *without changes* and will not be republished.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE PROPOSED RULE

During the past year, the RRC and the Mexican Comisión Reguladora de Energía (CRE) discussed issues relating to the development of cross-border projects. Based on comments solicited from companies that had business dealings in Mexico, the RRC focused on two issues in its discussions with the CRE: 1) difficulty in obtaining rights-of-way; and 2) delays in the permitting process. The RRC and CRE agreed to work on two initiatives: 1) a "single window" approach to permitting, with the RRC and CRE serving as "lead agencies" in assisting applicants; and 2) a "corridor concept" under which the two agencies would establish routes for future energy projects that included pre-approvals. The MOU adopted in this rule reflects an agreement among Texas agencies to establish the single window concept. The intent is to provide prospective applicants a single package containing all the necessary permit information with respect to Texas agencies, with RRC as the intermediary in dealing with those agencies. The RRC, in its role as the provider of the single window, may not usurp any of the powers of the other agencies or prevent necessary discussions between individual agencies and the applicant, but will simply serve as a guide for applicants.

SECTION DISCUSSION

New §7.125 describes the roles and responsibilities that the SOS, RRC, THC, GLO, TNRCC, and PUC will or may have in permitting natural gas pipelines that cross the border between Texas and Mexico. The role of the SOS is to assist the other agencies in organizing a permitting process in a manner that reduces the number of agency contacts a potential permittee must make and ensures that the applicant is aware of all the necessary Texas permits. The role of the RRC is to issue hydrostatic test water discharge permits; issue opinions to the United States Army Corps of Engineers (USACE) concerning Clean Water Act, §401, water quality certification; and review of requirements under USACE, Section 10, for navigability clearance. The role of the THC, as the state historic preservation office, is to ensure that adverse effects on historic properties are avoided or minimized. The role of the GLO is to issue easements for portions of the Rio Grande River that have not been deeded to the United States government. The role of the TNRCC is to issue permits to withdraw water, owned by the United States, from the Rio Grande River, its tributaries, and any other Texas stream for hydrostatic testing, and to issue permits for operations of certain pipeline facilities which emit air contaminants. The role of the PUC is to participate in the permitting process if necessary; however, it does not issue permits with respect to building natural gas pipelines that cross the border between Texas and Mexico.

The RRC, THC, GLO, and TNRCC have agreed to prepare an inventory of the various permits each agency may require with respect to building natural gas pipelines that cross the border between Texas and Mexico. The inventory will include a list of each agency's permits identified by name and/or number, and identify the appropriate staff contact person by name, phone number, and e-mail address for each permit.

The RRC, THC, GLO, TNRCC, and PUC also have agreed that the RRC should be designated as the distributor for applicable state permit applications, initial screener of completed applications for completeness, and facilitator among the other parties to the MOU for applicants who wish to build natural gas pipelines that cross the border between Texas and Mexico.

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed the new rule in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and determined that the rule is not subject to §2001.0225. Section 2001.0225 only applies to rules that are specifically intended to protect the environment, or reduce risks to human health from environmental exposure. This new rule is purely procedural. The intent of the rule is to formalize the procedures for cooperation among the TNRCC, SOS, RRC, THC, GLO, and PUC regarding permitting of natural gas pipelines that cross the border between Texas and Mexico, not to protect the environment or human health. Protection of human health and the environment may be a by-product of the rule, but it is not the specific intent of the rule. Furthermore, the rule will not adversely affect, in a material way, the economy, a section of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. Thus, the rule does not meet the definition of a "major environmental rule" as defined in Texas Government Code, §2001.0225(g)(3), and does not require a full regulatory impact analysis.

TAKINGS IMPACT ASSESSMENT

The commission prepared a takings impact assessment for this new rule under Texas Government Code, §2007.043. The following is a summary of that assessment. The specific purpose of this new rule is to set forth the procedures by which the TNRCC, SOS, RRC, THC, GLO, and PUC coordinate on issues related to permitting, licensing, or registration of natural gas pipelines that cross the border between Texas and Mexico. The rule will substantially advance this specific purpose by setting forth detailed procedures for such interaction including initial notification, document exchange, comments, and meetings. The rule does not constitute a takings because it will not burden private real property.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission reviewed the new rule and determined that the rule is neither identified in the Coastal Coordination Act Implementation Rules, 31 TAC § 505.11(b)(2), relating to Actions and Rules Subject to the Texas Coastal Management Program (CMP), nor will it affect any action or authorization identified in the Coastal Coordination Act Implementation Rules, 31 TAC §505.11(a)(6). Therefore, the rule is not subject to the CMP.

HEARING AND COMMENTERS

A public hearing was not held on the proposal, and no comments on the proposal were received.

STATUTORY AUTHORITY

The new section is adopted under Texas Water Code (TWC), §5.103, which authorizes the commission to adopt any rules necessary to carry out its powers and duties. Additionally, the new section is adopted under TWC, §5.104, which authorizes the commission to enter into an MOU with any other state agency but requires the MOU to be adopted by rule.

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 September 27, 2001.

TRD-200105853
Stephanie Bergeron
Division Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 17, 2001
Proposal publication date: June 29, 2001
For further information, please call: (512) 239-5017

♦ ♦ ♦

## CHAPTER 101. GENERAL AIR QUALITY RULES

The Texas Natural Resource Conservation Commission (commission) adopts amendments to §101.1, Definitions, §101.350, Definitions, §101.352, General Provisions, §101,353, Allocation of Allowances, §101.354, Allowance Deductions, §101.356, Allowance Banking and Trading, §101.360, Level of Activity Certification, §101.370, Definitions; §101.372, General Provisions;

§101.373, Protocols; and new §101.363, Program Audits and Reports. The amended and new sections will be submitted to the United States Environmental Protection Agency (EPA) as revisions to the state implementation plan (SIP). Sections 101.1, 101.350, 101.353, 101.354, 101.356, 101.360, and 101.373 are adopted *with changes* to the proposed text as published in the June 15, 2001 issue of the *Texas Register* (26 TexReg 4380). Sections 101.352, 101.363, 101.370, and 101.372, are adopted *without changes* and will not be republished.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

On December 6, 2000, the commission adopted amendments to Chapter 101, General Air Quality Rules, that established a program for the trading of nitrogen oxides ($NO_x$) emission allowances in the Houston/Galveston (HGA) ozone nonattainment area. The trading of these allowances takes place under an area-wide cap on $NO_x$ emissions established under the SIP in order to meet the national ambient air quality standard (NAAQS) for ozone. Each allowance is equal to the emission of one ton of $NO_x$ per year. The program requires incremental reductions in $NO_x$ emissions every year beginning in calendar year 2003 and continuing through calendar year 2007, when the full reductions of the program are to be achieved.

HGA is a severe ozone nonattainment area. When fully implemented the program will place stringent area-wide limits on the emission of $NO_x$ from stationary sources, and the trading program is intended to provide as much flexibility in meeting these limits as possible. Following adoption of the program, the agency continued discussions to determine the most effective way to implement the reduction and trading programs as smoothly and economically as possible while meeting emission reduction goals. The agency also continues to evaluate its own procedures used to implement the program for efficiency and effectiveness. These amendments are the result of these discussions and evaluations and also would correct typographic errors, outdated rule references and citations.

SECTION BY SECTION DISCUSSION

The amendments to §101.1 remove outdated references to §101.29, Emission Banking and Trading, which was repealed on December 6, 2000, and replace them with references to Chapter 101, Subchapter H, Division 1. Section 101.1 is changed from proposal to make minor editorial changes for clarity.

The amendments to §101.350 change the definition of "level of activity" to apply to facilities instead of sources. The amendments also remove the requirement that the units used to determine level of activity have a direct correlation with the economic output and emission rate of the source. The level of activity is only one factor used to determine allowance allocation and is not an emission rate. These changes are adopted to ensure the use of consistent terms and to clarify the current interpretation of the defined term. In response to a comment that the commission clarify the rule concerning level of activity certification for existing facilities, the commission is adding a definition of "existing facility." A description of what would be considered an existing facility was stated in the body of the rule language for the proposal. By including the term in the definitions the commission is able to reduce the volume of rule language and simplify the organization of §101.360. After consideration of another public comment, the commission is including a definition of "adjustment period" to address that period of time from first start-up to establishment of normal operating conditions for a new facility. All definitions have been renumbered to accommodate the two new definitions.

The amendments to §101.352 specify that only an owner or operator of a facility may certify emission reductions from the facility as emission reduction credits (ERCs), if approved by the executive director and the owner or operator meets all the requirements of Chapter 101, Subchapter H, Division 1, Emission Credit Banking and Trading. This language clarifies who may apply for certification.

In consideration of public comments, the commission is modifying the method of determining level of activity for existing facilities not in operation prior to January 1, 1997. This language is found in the equation variables located in the figure in §101.353(a), variable (2)(C). Owners or operators of facilities that are in this category may average any two consecutive years of activity within the first five years of operation. Under extenuating circumstances, the owner or operator may petition the executive director for an additional two calendar years. A principal goal of the cap and trade program is to provide incentive to make emissions reductions. The commission believes that owners or operators who install and operate cleaner equipment should have the opportunity to fully integrate that equipment at a realistic level of operation that is representative of the demands that will be placed on the equipment. The commission believes that a five-year period to establish a baseline will allow this integration.

The amendments to §101.353(a) correct typographical errors in the variables of the allocation equation and replace the term "source" with "facility." The commission used language in several places in the section that described an existing facility. In order to reduce the amount of rule language and better organize the section, the commission is replacing this language with the term "existing facility" which is now defined in §101.350. In response to comments, the commission is including language within the section that allows for a 180-day adjustment period in order to establish facility operating characteristics before the determination of baseline activity. Also in response to comments, the commission is modifying the emission factor variables used to determine the beginning allowances of a facility. As a result of this modification, the level of activity is either determined through the calculated emission factor or the emission specification for attainment demonstration (ESAD), whichever is higher. This change will allow facilities that operate at emission levels lower than those required under the SIP to receive allowances based on their ESAD rate and not be penalized for operating a cleaner facility. Because the attainment demonstration was based on the modeled ESAD rates, any allowance allocated based on the difference between actual emission rates and the ESAD will not jeopardize the demonstration because available allowances will not exceed the ESAD based cap. Based on the stringency of ESAD rates and the expense of controlling emissions below ESAD rates, the commission has concluded that a relatively few, if any, facilities will receive allowances in excess of their actual emissions. The commission has corrected the designation of emission factors, which were incorrectly labeled for years 1998 and 1999, in the equation in variable (A)(2) located in the figure in subsection (a) as a response to public comment.

The amendments to the figure in §101.353(a), variable (3)(A), adjust the factors for allocation of allowances to boilers, auxiliary stream boilers, and stationary gas turbines within an electric power generating system and add a more complete reference to 30 TAC §117.10(13)(A)(iii), Definitions. The commission is also adding language to include duct burners in turbine exhaust ducts as equipment within an electric power exhaust duct for consistency with 30 TAC §117.106(c)(3), Emission Specifications for Attainment Demonstrations. The adjustment would result in the allocation of allowances consistent with the following: 44% reduction beginning April 1, 2003; 88% reduction beginning April 1, 2004; and 90% reduction of $NO_x$ emissions from these facilities by April 1, 2007. These reduction percentages are based on the baseline emissions as reported in the 1997 emissions inventory. The commission's analysis of the air quality situation in the HGA area indicates that this reduction, along with reductions in $NO_x$ from other sources and from grandfathered facilities in east Texas, will result in a fully approvable attainment demonstration which shows attainment in the HGA area by November 2007.

The commission also adopts a new set of factors in a new variable (3)(B) for boilers, auxiliary steam boilers, and stationary gas turbines within an electric power generating system. These factors would become effective if the executive director determines that the science confirms the benefit during the mid-course review process. This process will involve a thorough evaluation of all modeling, inventory data, and other tools and assumptions used to develop the attainment demonstration. It will also include the ongoing assessment of new technologies and innovative ideas to incorporate into the plan. If such benefit is confirmed, then it is the intent of the commission to implement such a program through a SIP revision which will first offset $NO_x$ reductions from industrial sources down to the 80% (535 tons per day (tpd)) level. The commission, in its discretion, may allocate any additional benefit beyond 80% to other SIP strategies and/or to the point source $NO_x$ control strategy. Based upon current analysis, this 80% from utility and non-utility sources would result in a total reduction of not less than 535 tpd of $NO_x$ emissions from industrial sources in the HGA area. This alternative schedule would provide for overall reductions of $NO_x$ emitted from these facilities by 44% by April 1, 2003, and 88% by April 1, 2004. These reduction percentages are based on the baseline emissions as reported in the 1997 emissions inventory.

The amendments to §101.353(a) in variable (3)(C) of the figure adjust the allowance allocation schedule for non-utility facilities by requiring annual reductions in allowances to be spread over a five-year period, thus requiring smaller annual reductions. The commission adopts this adjustment to allow the affected industries more options for planning and implementing incremental reductions in emissions. The amendments do not affect the April 1, 2007 date of final allocation levels, nor increase final allocations or change the final emission reductions as required by the SIP. The formulas in §101.353(a), variable (3)(C) provide for overall reductions of $NO_x$ emitted from non-utility facilities by 35% by April 1, 2004; 60% by April 1, 2005; 70% by April 1, 2006; and 90% by April 1, 2007. These reduction percentages are based on the baseline emissions as reported in the 1997 emissions inventory.

The commission also adopts a new set of factors in a new variable (3)(D) in the figure in §101.353(a) for non-electric utility facilities. These factors become effective if the executive director determines that the science confirms the benefit during the mid-course review process. This process will involve a thorough evaluation of all modeling, inventory data, and other tools and assumptions used to develop the attainment demonstration. It will also include the ongoing assessment of new technologies and innovative ideas to incorporate into the plan. If such benefit is confirmed, then it is the intent of the commission to implement such a program through a SIP revision which will first offset $NO_x$ reductions from industrial sources down to the 80% (535 tpd) level. The commission, in its discretion, may allocate any additional benefit beyond 80% to other SIP strategies and/or to the point source $NO_x$ control strategy. Based upon current analysis this 80% from utility and non-utility sources would result in a total reduction of not less than 535 tpd of $NO_x$ emissions from industrial sources in the HGA area. This alternative schedule would provide for overall reductions of $NO_x$ emitted from non-utility facilities by 35% by April 1, 2004; 60% by April 1, 2005; 70% by April 1, 2006; and 75% by April 1, 2007. These reduction percentages are based on the baseline emissions as reported in the 1997 emissions inventory. The amendments to the figure in §101.353(a), variable (6) correct references to concurrently adopted rule citations in Chapter 117.

The amendments to §101.353(g) allow the executive director to give owners/operators up to an additional two years to establish a baseline of activity that better represents normal operation. The previous rule required the request to be submitted to the executive director by June 30, 2001. The amendment extends this option for owners or operators of facilities that have not completed two calendar years of activity by June 30, 2001, so that new facilities may also have this option.

Owners or operators applying for extenuating circumstances will be limited to an additional two calendar years to establish normal baseline activity for new or modified facilities if the first two calendar years of historical activity were not complete by June 30, 2001. Under the amendment, requests for this additional time must be submitted no later than 90 days from completion of the first two calendar years of actual activity.

The commission concludes that any allowances added to a facility to represent normal operation will not exceed the number of allowances subtracted from the cap due to the difference between allowances issued to new facilities based on allowable emissions and the number of allowances issued to those same facilities based on actual emissions once a two-year baseline is established. A review of emission inventory records shows that a majority of facilities operate well below their allowable emissions which supports the commission's conclusion that facilities which obtain allowances which represent normal operation will not increase the cap beyond the level modeled in the attainment demonstration. The commission will reconcile the total number of allowances during annual reports and audits of the program to ensure that the program is meeting its expected goals.

The amendments to §101.354(a) add language clarifying that established protocols in 30 TAC Chapter 117 should be used when quantifying actual emissions for facilities subject to the cap and trade program unless the executive director approves the use of the existing formula in §101.354(a) or another method. This establishes a protocol to demonstrate compliance that has been reviewed and approved by the EPA and thus satisfies the EPA concerns relating to using an EPA- approved protocol for a regulation which is a SIP requirement. In response to public comment, the commission is modifying §101.354(a) to include specific references to those sections of Chapter 117 that address monitoring and testing protocols used in the cap and trade program.

The commission is adding a new §101.354(b) that provides a procedure which may be followed to determine actual emissions in the event the data required under §101.354(a) is missing or unavailable. The procedure establishes the order of missing data methods that must be used as follows: continuous monitoring; periodic monitoring; stack or vent testing data; manufacturer's emissions data; and *EPA Compilation of Air Emission Factors* (AP-42). These methods must be demonstrated to most accurately represent actual emissions. The figure that was located in subsection (a) has been moved to subsection (b).

The commission is adding a new §101.354(c) to establish consistency between the protocols used to allocate and deduct allowances. This will ensure that allowances are not deducted from compliance accounts at a higher or lower rate than they were allocated. For example, if the allocation of the allowances was based on assumed emission factors, and the facility subsequently installs a continuous emission monitoring system (CEMS) which shows a lower actual emission rate, the facility could state that it had achieved emission reductions simply by changing its method of measurement. Additionally, if a facility originally based its throughput on hours of operation, but changed the method of measurement to fuel consumption in order to use a more accurate measurement, the resulting difference in activity level may alter the number of allowances allocated because allowances are based on level of activity. The new subsection provides the executive director the discretion to determine the consistency between allocation and deduction protocols. It is the intent of the commission that the reductions achieved under the cap and trade program are real and not based solely on differences of measurement. All subsequent subsections are redesignated.

The amendment to the newly designated §101.354(f) requires that a site hold a quantity of allowances in its compliance account on March 1 that is equal to or greater than the total $NO_x$ emissions for the prior control period. This extends the date one month from February 1, which is currently required. This allows site owners or operators the entire month of January to complete trades of allowances to reconcile their compliance accounts for the prior control period as was the original intent of the commission. Because trades are required under §101.356(f) to be submitted to the executive director at least 30 days prior to being approved and deposited into compliance or broker accounts, trades requested on or after February 1 will not be reflected in the compliance determination for the prior control period.

The amendments to §101.356 add a new subsection (c) that allows the owner or operator of a site receiving allowances on an annual basis to permanently sell those rights to any person to eliminate the need to make an annual transaction. All subsequent subsections are redesignated. The commission also deletes subsection (g), which concerns program audits and places those requirements into the new §101.363.

The amendment to §101.356(f) states that the executive director will review trades of allowances for approval. This language is added to clarify that trades of allowances are not complete until approval by the executive director.

The amendments to §101.356(g) add two steps to the devaluation, in respect to emission allowances, of banked discrete emission reduction credits (DERCs) and extend for two years the date at which DERCs are devalued to a ratio of ten DERCs to one allowance. Use of DERCs will continue to be limited to 10,000 per year beginning January 1, 2005, under §101.356(g)(7). The commission extends this flexibility to preserve as much credit as possible for those industries that have made early emission reductions while still achieving the anticipated environmental benefits of the cap by 2007. Any substitution of DERCs for allowances is subject to the approval of the executive director. The commission notes that the EPA has indicated in the *Federal Register*, when proposing approval of this division as an amendment to the SIP, that it will not approve the use of DERCs or mobile discrete emission reduction credits (MDERCs) in lieu of allowances until such time that Chapter 101, Subchapter H, Division 4, Discrete Emission Credit Banking and Trading, is approved as a SIP amendment. The EPA has also indicated to the commission that it anticipates approval of Division 4 well before January 2003. The EPA has indicated that if an owner or operator wished to use DERCs or MDERCs in lieu of allowances prior to approval that this could take place as a site-specific SIP revision. Based on the timeline for approval as indicated by the EPA and based on the fact that this date is in advance of the first annual reporting requirement of the cap and trade program, the commission does not anticipate a significant number of site-specific requests if required by the EPA.

In response to public comment, the commission is adding a new §101.356(h) to expand the use of emission credits, whether DERCs or ERCs, as allowances. The expanded use of emission credits allows the conversion of ERCs to a yearly allocation of allowances if the ERCs were generated prior to December 1, 2000. The ERCs generated prior to that date were included in the attainment demonstration modeling for the HGA on the assumption that the credited emissions would reappear once the ERC was sold or transferred. These ERCs would therefore not affect achievement of the final $NO_x$ cap for the HGA area, so this will not be an attainment demonstration issue. The commission does not have the same level of confidence concerning the effect of ERCs generated after December 1, 2000, on the HGA $NO_x$ cap and is not including these ERCs as eligible for conversion. The commission will continue to evaluate their potential effect on the cap. The commission notes that the EPA has indicated that the use of ERCs will be treated similarly to the use of DERCs and MDERCs as explained in the previous paragraph.

The amendments to §101.360 clarify that owners or operators certifying their levels of activity will need to include emission factors in their report which will be used, along with level of activity, to establish the number of allowances the site will receive. The commission is revising the language in §101.360(b) for consistency with the method of determining activity level for existing facilities not in operation prior to January 1, 1997.

The commission adds a new §101.360(c), which requires the owner or operator of a site which becomes subject to the cap and trade program after April 1, 2001, to certify the site's level of activity no later than 90 days from the date the site becomes subject to the division. The commission adopts this subsection to include those sites that currently have facilities with a collective design capacity of less than ten tons per year of $NO_x$, that at some future date add facilities or capacity that brings the collective design capacity to ten tons or more. In response to public comment, the commission has reorganized this subsection for clarity.

The new §101.363 incorporates the audit requirements of the previous §101.356(g) which the commission is repealing, and adds a requirement for an annual program audit report from the executive director to be made available to the EPA and the public. The audit procedures remain unchanged. The procedures require the executive director to evaluate the effectiveness of the cap and trade program as implemented by Chapter 101, Subchapter H, Division 3, Mass Emissions Cap and Trade Program, on the ozone attainment demonstration. The audit includes the availability and cost of allowances and compliance by participants. The executive director will recommend measures to remedy problems with the program, including the cessation of allowances, emission reduction credit, and discrete emission reduction credit trading. The new requirement for an annual report includes information on allowance allocation and trading by account and on the total number of allocations and trades completed. This report would be made available by June 30 after the end of each control period. The provision for an annual report is included in response to a request by the EPA.

The amendments to §101.370 state that the definitions of "activity" and "level of activity" apply to facilities instead of sources. The amendments remove the requirement that the units used to determine level of activity have a direct correlation with the economic output and emission rate of the source. The level of activity is only one factor used to determine allowance allocation and is not an emission rate. The commission is amending the definition of "strategy emission rate" to state that this term is the emission rate during a DERC generation period. The commission is adopting these changes to ensure the use of consistent terms and to clarify the current interpretation of the defined terms.

The amendment to §101.372(b)(2) removes the requirement that a MDERC be surplus when it is used, because MDERCs are not certified until after the reduction has actually occurred. This certification results from an evaluation of the MDERC, which is not perpetual, at the time of certification and removes the need for another evaluation at the time of use.

The amendment to §101.373(c)(1)(A) adds temporary shutdown of a source to the list of activities that cannot generate a DERC. This clarifies the existing DERC regulations that do not allow generation of DERCs from temporary curtailments. In order to allow greater credit for the generation of DERC fractions, the commission is revising §101.373(d)(1)(A) to state that the generation of DERCs will be rounded up to the nearest tenth of a ton.

The amendment to §101.373(f)(3) deletes the reference to the expiration of DERCs, because DERCs do not expire until used. The amendments to §101.373(f)(6)(C) and (D) correct rule citations. In order to give more flexibility to the use of DERCs, the commission is revising §101.373(f)(8)(C) to allow the rounding up of DERCs needed to comply with 30 TAC §117.223, relating to Source Cap, to the nearest tenth of a ton.

The amendments to §101.373(g) require that an application to use DERCs be submitted to the executive director and that approval shall be received prior to use of the DERC. This allows the executive director to confirm that the DERC use complies with regulations. Several changes are made in the subsection to remove the term "notice of intent to use" and replace with "application of intent to use." These changes clarify that approval is required before a DERC is used.

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 rules do not meet the definition of "major environmental rule." A "major environmental rule" means a rule, the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure, and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. The commission intends these amendments to provide additional planning options to affected industries during the five-year period in which allocations under the cap and trade program are reduced to their final levels. The schedule for full implementation and the final level of allocations would be unaffected. The amendments would allow participants in the program additional options for the permanent sale of allowances, an extension of the period to request deviations from allocation methods, and additional time to make final trade reports after the end of a control period. The amendments do not increase the stringency of the program and will not 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.

In addition, Texas Government Code, §2001.0225, only applies 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. This rulemaking is not subject to the regulatory analysis provisions of §2001.0225(b), because the rules do not meet any of the four applicability requirements. Specifically, the emission banking and trading requirements within this rulemaking were developed in order to meet the ozone NAAQS set by the EPA under the Federal Clean Air Act (FCAA), §109, as codified in 42 United States Code (USC), §7409, and therefore meet 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.

TAKINGS IMPACT ASSESSMENT

The commission completed a takings impact assessment for the adopted rules. The following is a summary of that assessment. The commission is adopts these amendments 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 amendments 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 that are the subject of these rules are not property rights. Consequently, these amendments do not meet the definition of a takings under Texas Government Code, §2007.002(5). The purpose of the rules is to provide flexibility in a $NO_x$ control strategy which is necessary for the HGA area to meet the 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, these revisions do not constitute a takings under Texas Government Code, Chapter 2007.

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission determined that 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 reviewed this action for consistency with the CMP goals and policies in accordance with the regulations of the Coastal Coordination Council and 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. The amendments will allow greater compliance flexibility for affected industries while reducing emissions of $NO_x$ in the HGA nonattainment area to a level that would allow attainment of the NAAQS for ozone. No new emissions of air contaminants are authorized by these rules.

The commission solicited comments on the consistency of the proposed rules with the CMP during the public comment peiod, but received no comments.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMITS PROGRAM

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

PUBLIC HEARING AND COMMENTERS

The commission held public hearings on the proposal on June 13, 2001 in Galveston; June 14, 2001 in Rosenberg and in Houston; June 15, 2001 in Austin; and July 2, 2001 in Houston.

BASF Corporation (BASF), BP Amoco (BP), BCCAAG, Enterprise, Environmental Defense (ED), EPA, ExxonMobil, Galveston-Houston Association for Smog Prevention (GHASP), Houston- Galveston Area Council (HGAC), Houston Sierra Club (Sierra), Reliant Energy (Reliant), Reliant Energy Channelview, L.P. (Reliant Channelview), Sempra Energy Resources (SER), Texas Chemical Council (TCC), Texas Industrial Project (TIP), and an individual submitted comments during the public comment period which closed on July 2, 2001. ED, GHASP, and Sierra opposed the proposal. EPA requested clarification of several points. The other commenters generally supported the concept of the proposal but opposed specific provisions.

ANALYSIS OF TESTIMONY

In January 2001, the Business Coalition for Clean Air Appeal Group (BCCAAG) and others filed suit against the commission challenging the December 6, 2000 SIP revision for HGA and five of the ten sets of rules associated with that SIP revision. As part of that lawsuit, the plaintiffs sought a temporary injunction to stay the effectiveness of these five sets of rules and for the commission to withdraw the SIP from EPA consideration; a hearing on this request was held in Judge Margaret Cooper's court, Travis County, Texas, May 14 - 18, 2001. Before that hearing was completed, an agreement in principle was reached to settle the lawsuit, and a Consent Order was entered by Judge Cooper which includes certain specific items included in the SIP revision and rules in Chapters 101 and 117 proposed by the commission on May 30, 2001 (26 TexReg 4380 and 4400). In support of its position that certain testimony in that hearing establishes the infeasibility of the $NO_x$ reduction and that the air dispersion modeling used by the commission is not reliable, BCCAAG submitted the transcript from the hearing as comments on these proposals. The hearing transcript included testimony from BCCAAG's witnesses, as well as the commission's witnesses, and therefore presents both sides of, or two different opinions on, some of the issues. Many of the documents introduced as exhibits in the hearing predate the rule changes and SIP revision proposed by the commission in the June 15, 2001 issue of the *Texas Register* and do not specifically address these rule changes and SIP revision. In addition, BCCAAG submitted as comments its First Amended Petition in the lawsuit and BCCA's comments from the earlier SIP, both of which were created before the settlement in principle was reached. While BCCAAG supports the substitution of new ESADs and other rule language from the Consent Order, it is not clear as to what other specific changes to the SIP and rules should be considered in this adoption in response to these particular comments.

As discussed earlier in this preamble, BCCAAG submitted the entire transcript of the May 14 - 18, 2001 temporary injunction hearing held before Judge Margaret Cooper, Travis County District Court, concerning the lawsuit styled BCCA Appeal Group, et al v. TNRCC. A witness, Jess McAngus (McAngus), testified that he does not believe that the cap and trade market will develop because, based on his conversations with companies, "no one expects to be able to overcontrol," and any companies that generate credits have "indicated that they're going to keep them for themselves for a margin of error." McAngus testified that the credits will "be too valuable to the company for them to sell" to someone else. Another witness, Doug Deason testified that ExxonMobil does not expect to have any excess credits from overcontrol.

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 alternative control techniques (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 selective catalytic reduction (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 retrofitted to levels below the existing ESADs and further details of the technical feasibility of the ESADs can be found elsewhere in this preamble and in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)). 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 contemplated in the preamble to the Chapter 117 proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275). Although the number of SCRs is expected to be unprecedented, the ultimate number installed is almost 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 existing rules gives 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.

ED and GHASP objected to the addition of another step in the emission reduction schedule in §101.353. ED stated that the revised schedule is not as expeditious as practicable and that there is no compelling reason for the revised schedule.

The commission adopted this change to allow the affected industries more options for planning and implementing incremental reductions in emissions. This schedule is practicable given the financial and technical resources necessary for individual companies and all sources in the HGA ozone nonattainment area to comply with the required emission reductions. The amendment would not affect the March 31, 2007 final compliance date, would not increase final emission rates, and would still achieve the final emission reductions as required by the SIP. The revised compliance schedule was provided by BCCAAG as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described earlier in this preamble.

BASF commented that the proposed cap and trade rules combined with new source review (NSR) will limit the ability of industry to make changes at sites because reductions will be required beyond those required to show attainment with the ozone standard. BASF and TIP recommended the use of Plant-wide Applicability Limits (PALs) instead of netting or revision of §101.352(d) to allow the use of allowances for project netting.

The commission is not revising the rule in response to this comment. Federal rules require that an offset be applied to major new or modified projects. The offset includes a ratio which varies depending on the attainment status of an area. The ratio is intended to provide a net benefit in the form of emissions reduction to the airshed with the approval of each project. Until such time that the commission and the EPA determine that the benefits of the cap and trade program are equivalent to the benefits of requiring offsets, both programs will be enforced.

BASF, BCCAAG, Enterprise, and TIP commented that §101.353(a)(2)(A) should be revised to properly designate the variables for 1998 and 1999 emission factors.

The commission is revising the rule to correct the designation errors.

BCCAAG, Enterprise, and TIP commented that there should be no trading restrictions on unused allowances from unmodified facilities under a flexible permit and that facilities should not be treated differently for the allocation of allowances based on the type of NSR authorization. The Flexible Permit Guidance (FPG) issued by the commission provides that all facilities subject to the permit are considered modified when any facility subject to the permit is modified. This prohibits trading and banking of allowances for all facilities under the permit. TIP cited the preamble to final rules adopting the flexible permit program where the commission states "...the permit is not reopened with respect to facilities for which an amendment, revision, or modification is not sought...." This was in response to a comment that reopening of flexible permits should be limited to a review of the facility affected by the change. TIP stated that the policy should include an allowable for a modified facility, based on the modification, that can be used by any facility covered by the flexible permit. This allowable could not be used by facilities at the site which are not covered by the flexible permit, nor could the allowable be traded to another site. BCCAAG, Enterprise, and TIP commented that the FPG also constitutes a rule subject to the Administative Procedures Act (APA) because it alters §101.353(a)(2)(B).

The commission is not revising the rules in response to these comments. The commission's intent when allocating allowances to a new or modified facility is to provide sufficient allowances based on the facility's authorized allowables until such time the facility can establish a baseline. This intent also includes projects where modifications may include reductions and shutdowns of other facilities. Therefore, when the entire modification project is completed, the owner or operator can operate the affected facilities in their final configuration for a two-year period to establish the baseline. When determining which facilities are new or modified, the commission's intent is to use the same criteria as used in NSR. In the case of facilities under a flexible permit cap, anytime that the cap is increased or otherwise modified, all facilities under the cap are also considered modified. This decision is based on the fact that at anytime an individual facility has a potential to increase emissions, change the method of controls, or change the characteristics of its emissions, it is considered modified. For example, when a flexible permit cap is increased, any individual facility under the cap can potentially increase its own emissions. In response to the language in the preamble for the regulations that authorized flexible permits, the commission stated that when a flexible permit is opened for modification, that a full review only be applied the facilities physically being changed. This was intended to eliminate retroactive best available control technology (BACT) reviews for all facilities under the cap every time the flexible permit was amended. The language in the preamble was not intended to imply that facilities under a flexible permit which was amended are not modified. For these reasons, the commission intends to consider all of the facilities under a capped portion of a flexible permit to be modified if any facility under that cap is new or modified. Consequently, all facilities under the capped portion of a flexible permit will receive allowances based on allowables if the cap includes any new or modified facility. These facilities will continue to receive allowances on this basis until such time that all construction as represented in the permit application (administratively complete prior to January 2, 2001) is complete and the affected facilities have established a new two-year baseline.

BCCAAG, Enterprise, and TIP commented that a 180-day shakedown period should be incorporated into the formula for allowance allocation. The two-year baseline for the allocation of allowances should not include this period because emissions during shakedown often are not representative of normal operations.

The commission is revising the rule in response to these comments. It was not the intent of the original rule to include any start-up period when establishing the two-year baseline period, and the commission is adding language to clarify this point.

Reliant Channelview commented that sources that have been modified to emit at less than an ESAD rate should be allocated allowances based on the higher emission rate modeled for the SIP. This will ensure that the modified unit, which will be more efficient and cleaner, will have sufficient allowances to operate at maximum capacity.

The commission is revising §101.353 in response to this comment to allow facilities that emit at below the ESAD rate to use the ESAD rate as their baseline for determining the allocation of allowances.

BCCAAG, Enterprise, and TIP commented that they support the addition of §101.353(g) concerning extenuating circumstances for allowance allocation, but they are greatly concerned about the guidance issued by the commission for the application of this policy. No conditions are imposed on the executive director on the exercise of his discretion in granting a timely application. The procedure restricts consideration to five limited circumstances. TIP objected particularly to the requirement that a facility demonstrate a 25% site-wide activity difference. This policy penalizes facilities that may meet the required activity drop but are co-located with facilities that do not. The result is an allocation of allowances for the site that is well below the emissions expected if both facilities were operating at a normal authorized rate. BCCAAG, Enterprise, and TIP contended that the Extenuating Circumstances Guidance (ECG), if enforced, is a rule for which the commission has not complied with the APA. The ECG does not just provide factors to be considered before granting extenuating circumstances but limits the application of executive director discretion. In effect the ECG revises §101.353(g) without formal rulemaking procedures as required under the APA.

The commission is not changing the rule in response to these comments. The guidance mentioned by the commenters lists several factors that the executive director will consider in making a decision concerning extenuating circumstances for alternate level of activity certification. These factors include the 25% activity difference for an alternate period, as stated by TIP. Because of the importance of maintaining the emissions cap in the HGA area, the commission intends that qualification for an alternate level of activity period be a rigorous and well documented activity. The executive director will consider the factors in the guidance, but these factors do not limit the exercise of his discretion to consider all extenuating circumstances.

ExxonMobil commented that §101.353(g), concerning extenuating circumstances, is unnecessarily restrictive and can have the net effect of reducing maximum effect capacity for the life of some facilities. ExxonMobil recommended that less restrictive guidance be developed which allows the agency to consider market conditions during the 1997 - 1999 baseline period as a valid reason to use a different three-year period to establish the baseline. ExxonMobil also recommended that the baseline should be adjustable in future years. ExxonMobil stated that the commission should also issue guidance to allow facilities to set activity levels necessary to meet capacity needs of the future.

The commission is not changing the rule in response to this comment. Section 101.353(g) gives the executive director discretion to deviate from the allowance allocation requirements, including the determination of a baseline of activity in the future. The section does limit the executive director to allowing no more than two additional years for establishing a baseline for new or modified facilities. This section only limits the dates when an owner or operator of a facility may apply for extenuating circumstances. In addition, this section does not specify what requirements the applicant must meet to request extenuating circumstances. The executive director has established guidelines for the general consideration of applications for extenuating circumstances; however, the guidance is not regulatory and does not limit the executive director's discretion to grant extenuating circumstances in cases that deviate from the guidance.

The commission requested comments on alternative methods for allocating allowances to new boilers, auxiliary steam boilers, and stationary gas turbines within an electric power generating system. ExxonMobil, SER, and TCC responded to this request. SER commented that a two-year extension for baseline determination is preferable to the current cap and trade base, but may not be sufficient to allow new power plants serving a high growth area such as Montgomery County to accumulate sufficient operation time to determine a representative baseline. This could force the higher efficiency new units into a situation where they must either limit operation and defer to older and dirtier units or purchase allowances. This is not consistent with promoting environmental benefits and energy reliability. SER preferred a seven year extension, but recommended that the commission adopt a program that allows facilities to receive allowances equal to actual emissions scaled up to full capacity with the limitation that allowances not used in the year they were allocated could not be banked. SER expressed the belief that this policy will encourage the maximum use of high efficiency generating stations, such as those proposed by SER for Montgomery and Liberty Counties, with the resulting $NO_x$ reductions. Sierra opposed the seven-year option. SER opposed a program where the commission retains allowances and makes them available to new units because of the difficulty in determining annual needs for a new facility. TCC commented that allowances for any new or modified facilities should be established permanently on the allowables and should not be based on the two-year baseline. ExxonMobil stated that they support all four options listed in the proposal with the comment that if a hold back of allowance for new facilities is chosen, it not be limited to only utilities but extended to all point sources which have a similar need to operate with a high degree reliably. An individual opposed any grace period for industrial sources to establish a baseline of activity.

The initial allocation of allowances based on allowable emissions for new facilities is intended to provide the facilities sufficient allowances to operate until they have established a baseline. The allocation is not intended to provide allowances that will be perpetually greater than actual emissions as this would give new facilities an unfair advantage over existing facilities whose allowances are based on an established baseline and not on capacity. However, a principal goal of the cap and trade program is to provide incentive to make emissions reductions. The commission believes that owners or operators who install and operate cleaner equipment should have the opportunity to fully integrate that equipment at a realistic level of operation that is representative of the demands that will be placed on the equipment. The commission believes that a five-year period to establish a baseline will allow this integration. In order to provide flexibility, the commission is revising §101.353 to allow the averaging of any two consecutive years in the first five years of operation of a new or modified facility as a baseline and will allow the owner or operator, under extenuating circumstances, to obtain a further two-year extension with executive director approval.

BCCAAG, Enterprise, and TIP commented that a reference to Chapter 117 in §101.354(a) be made more specific and refer to section numbers.

The commission is revising the rule in response to this comment to include specific references to the sections of Chapter 117 concerning monitoring and compliance protocols.

EPA commented that §101.354(a) should be revised to state what data will be used if Chapter 117 monitoring is not available, and that this data must be approved by the executive director and EPA. EPA stated that this rule should also be revised to state that missing monitoring data will be addressed in protocol revisions. BCCAAG, Enterprise, and TIP commented that the formula in §101.354(a) for deducting allowances should be deleted and replaced with a requirement that the deduction will be based on actual emissions reported to the commission for a control period. They also stated that not all emissions are determined using emission factors and §101.359 allows other emission determination methods.

The commission is revising the rule in response to these comments to clarify that the monitoring protocols in Chapter 117 will be used if such data is available and to specify a hierarchy of data to be used in the absence of Chapter 117 protocols. This hierarchy is: continuous monitoring data; periodic monitoring data; testing data; manufacturer's data; and *EPA Compilation of Air Pollution Emission Factors* (AP-42). The rule has also been revised to state that, in addition to the approval of the executive director for the use of alternative protocols, the information concerning the protocols will be made available to the EPA which will have 30 days to disapprove. The commission is retaining the formula as an additional option to Chapter 117 protocols, but its use is not mandatory.

ExxonMobil commented that §101.354(e) which extends the date by which a site must hold sufficient $NO_x$ allowances in its compliance account for the prior calendar year from February 1 to March 1 is a move in the right direction but still creates a tight schedule for industry to meet. ExxonMobil recommended that the date be extended to April 1 or preferably to May 1. BP and TCC recommended extending the reconciliation period to March 31 (a full calendar quarter).

The commission is not changing the rule in response to these comments. The commission believes that it is reasonable for owners and operators to track their emissions throughout the control period so that they will have a close approximation of the number of allowances they will require throughout a control period. The reconciliation period is intended to allow companies to quantify their last few weeks of emissions and to balance compliance accounts where a relatively limited number of allowances are needed. The reconciliation period is not intended to provide a period of time for large allowance deficits to be corrected. With these assumptions, the commission believes that the reconciliation period as proposed is sufficient time to determine actual emission and purchase any additional allowances.

Reliant supported the use of emission credits and transfer of surplus allowances to add additional flexibility to the cap and trade program.

The commission appreciates this support.

BP and TCC generally supported the language in §101.356 that allows owners or operators of a site to permanently sell their rights to allowances. BP and TCC stated that this will eliminate the requirements of completing annual transactions thus reducing the paperwork burden.

The commission appreciates this support.

Reliant commented that the commission should calculate allowables for modified facilities with respect to the new activity and not the facility as a whole. Thus the trading restriction in §101.356(c) would only apply to unused allowances generated by the modified activity. The remainder of a facility's allowances could then be transferred to other units as needed.

The commission is not revising the rule in response to this comment. The executive director participated in numerous meetings with stakeholders and evaluated many options on how to allocate allowances to new and modified facilities. The option described by Reliant was discussed in detail. However, in order to be most fair to all affected facilities, and due to the complexity of separating a single facility into separate allocation methodologies and tracking the use of allowances under these methodologies, the commission chooses not to adopt this option.

BASF, BCCAAG, Enterprise, and TIP commented that §101.356 should be revised to allow the conversion of ERCs into allowances. BASF commented that the restriction against this conversion lacks reasoned justification.

The commission is revising the rule in response to these comments by adding a new §101.356(h). The commission agrees that ERCs generated prior to December 1, 2000, were evaluated and included in the HGA attainment demonstration. Therefore, these ERCs, if converted into a stream of allowances would not increase emissions beyond those levels modeled that demonstrated compliance with the NAAQS for ozone. The new §101.356(h) to allows these ERCs to be used as allowances subject to approval of the executive director. The commission has evaluated the use of ERCs generated after December 1, 2000, and has concerns that these ERCs could be detrimental on the final level of the $NO_x$ mass emissions cap. These concerns include the use of ERCs generated from mobile sources and from stationary sources which are not covered under the cap and trade program. The executive director will continue to evaluate the conversion of ERCs generated after December 1, 2000, into a stream of allowances and will make a recommendation to the commission concerning future rulemaking.

ExxonMobil commented that the wording in §101.360(a) - (c) be consistent and that the language should be clarified as to what information is required in the certification.

The commission is revising the rule in response to this comment. The commission has reorganized the section and added a definition for existing facility for clarity and to reduce the length of the section. The information specified in the section is intended to be an example of the minimum information required. The commission may require additional information to support the application form and has intentionally left this discretion to the executive director because each facility will require a case-by-case determination.

BCCAAG, Enterprise, and TIP commented that a three-year audit of the cap and trade program is too infrequent to determine the program's effectiveness in providing cost-effective compliance and flexibility. They suggested an annual audit.

The commission is not revising the rule in response to these comments. The commission believes that a comprehensive audit will be sufficient to evaluate the program fully. The commission will compile data annually for the annual report, as required in §101.363, which will allow the commission as well as other interested stakeholders to evaluate the effectiveness of the program.

HGAC supported the review of the cap and trade program to allow for growth as new technologies are introduced.

The commission appreciates the support.

GHASP commented that the cap and trade program could have potential environmental justice issues as it relates to volatile organic compounds (VOCs) emissions. The commission should demonstrate that this program will not harm communities due to cumulative emissions. Sierra commented that the cap and trade program allows some industry to avoid reductions which will affect specific areas creating an environmental justice issue. Sierra also opposes the cap and trade rules in general and a system of command and control.

The commission has not revised the rule in response to these comments. The cap and trade program is a $NO_x$ reduction program and does not affect rule or emission limits for VOCs. The commission's $NO_x$ reduction strategy is regional and is intended to achieve a target level of reduced regional $NO_x$ and subsequently a reduction in ozone. The commission believes that this strategy will lead to public health benefits for the entire region. The program does allow the trading of emission allowances for compliance flexibility, but the purchase of allowances does not allow individual emission limitations in permits or other authorizations to be exceeded. When establishing permit limits, the commission reviews the permitted emissions limits for off-property health effects.

ED commented that the proposal backslides from the December 2000 adoption by delaying the schedule by which DERCs are devalued. ED recommended that the commission adopt a schedule at least as expeditious as the one originally adopted in December 2000.

The commission has not revised the rule in response to this comment. The delay in devaluation of DERCs will not jeopardize achievement of the final emissions cap or the 2007 compliance deadline. DERCs are created by a voluntary reduction in emissions beyond that required under rules. While the commission recognizes the importance of achieving the $NO_x$ emissions cap in the HGA area, the commission also believes that rewarding voluntary reductions is consistent with a market-based emission reduction program like the mass emission cap and trade program. The commission therefore believes that it is appropriate to maintain the value of DERCs as long as this is consistent with achievement of the regional emissions cap.

BP commented that allowances based on allowables should not be prohibited from trading pending establishment of a two-year historical baseline. BP acknowledged the commission's concerns for not allowing this trading but expressed the belief that some trading would provide the needed flexibility for industry.

The commission is not revising the rule in response to this comment. Allowances based on allowables are intended to provide new facilities the ability for initial operation under the cap and trade program. The allocation is not intended to provide allowances that will be perpetually greater than actual emissions because this action would give new facilities an unfair advantage over existing facilities that have allowances based on an established baseline and not on capacity. Even though the commission modeled the allowable emissions from new sources, this was done to model a worst-case scenario and was not the intended to continue to provide allowances based on maximum design capacity.

BP and TCC commented that the commission should clarify that the reasonably available control technology (RACT) final control plan is invalidated once the mass cap and trade program becomes effective. They commented that it will be confusing and complex if the commission requires compliance with both the RACT control plan and cap and trade.

No changes were proposed to §117.215(e), Final Control Plan Procedures for Reasonably Available Control Technology, which requires that the $NO_x$ RACT final control plan be updated with any emission compliance measurements submitted for units using CEMS or predictive emissions monitoring system (PEMS) and complying with an emission limit on a rolling 30-day average. The $NO_x$ RACT final control plan was due by November 15, 1999, for sources in BPA and HGA, and final compliance with the RACT requirements for these sources was required by November 15, 1999. Implementation of the Chapter 101 mass emissions cap and trade program will begin on January 1, 2002. However, the emission reductions required by the mass emissions cap and trade program will not be fully implemented until April 1, 2007. The commission agrees that updates to the $NO_x$ RACT final control plan are no longer necessary after that date in HGA. The commission notes that guidance on the final control plans is available on the commission's website at: *http://www.tnrcc.state.tx.us/oprd/forms/fcp.html*. Changes that could trigger a revision to a final control plan include construction of new units with the same product output as units complying with the source cap, and changes to maximum rated capacities, applicable limits, or assigned limits.

BP and TCC commented that the NSR should be streamlined. BP commented that the commission should work with industry to clarify necessary changes in the NSR program, which would simplify permitting.

This rulemaking does not address the issuance of NSR permits. The commission continues to examine methods of making NSR permitting more efficient and will consider specific recommendations from affected industries concerning changes to the permitting process.

BASF, BCCAAG, Enterprise, and TIP commented that the rules should be revised to state that emissions should be based on the best data available at a given time. BASF stated that if new emission measuring technology is established that it should not have to be retroactively applied.

The commission is not revising the rules in response to these comments. Implementation of the commenters' suggestions could result in the individual allocation of allowances that is consistently higher than those needed to operate the source. The commission believes that this would remove the incentive to make actual emission reductions or result in a continuous surplus of allowances, giving the owner of those allowances a competitive advantage.

EPA commented that the commission should clarify in response to comments that Texas Water Code (TWC), §7.051 and §7.052 allow the commission to impose penalties where every day of a long term violation is a separate violation.

EPA's interpretation of these statutes is correct; each day of noncompliance is a separate violation. Thus, everyday that the annual cap is exceeded can be considered as a separate violation.

EPA commented that the commission should clarify in response to comments that information from regulated sources that is exempt from public disclosure cannot be used to perform emission calculations. EPA also requested that any exemptions from disclosure be noted in the annual compliance report to EPA.

The commission agrees with EPA that emissions data cannot be held confidential. It is the Office of the Attorney General that makes such a determination in specific cases. Attorney General Opinion No. H-539 (February 26, 1975) ruled that emissions data supplied to the state may not be treated as confidential. Emissions data has been interpreted to include information on the nature and amounts of emission from a facility. The commission will include any notice of exemptions from disclosure in the annual report.

EPA commented that the commission should indicate, in its response to comments, that it will notify metropolitan planning organizations (MPOs) each time MDERCs are used until such time this responsibility is placed on the credit generator.

The commission agrees that MPOs should be made aware of mobile emission reduction credit (MERC) and MDERC generation projects because of the necessity to avoid double count reductions that may be banked and also be assumed to occur as part of the SIP.

EPA requested that the commission clarify how Alternate Emission Limits (AELs) may be used without exceeding the $NO_x$ emissions cap.

The commission is not revising the rule in response to this comment. The cap and trade program uses ESADs as listed in §117.106 and §117.206, Emissions Specifications for Attainment Demonstrations, and §117.475, Emissions Specifications, when calculating the number of allowances to allocate. AELs may not be used or requested in lieu of ESADs as specified in §117.106(e)(3) - (4) and §117.206(f)(4). There is no provision in the commission rules to allow for a variance from the Chapter 117 requirements. The commission recognizes that facilities with a capacity factor of 0.0383 have an ESAD of 0.060 lb $NO_x$/MMBtu regardless of facility type, as allowed in §§117.106(c)(4), 117.206(c)(17), or 117.475(c)(6). This ESAD is not an "AEL" but simply an assigned ESAD for facilities that are rarely utilized.

EPA commented that the commission should clarify that emissions offsets must be obtained for the life of the NSR source.

The commission agrees that offsets must be provided by the owner or operator of a facility for the life of that facility. The commission also agrees that, in order for reductions from a facility which is subject to the cap and trade program to be used as offsets, the owner or operator must permanently retire the rights to the allowances associated with that facility. This, in effect, generates ongoing credits which can be used as offsets for the life of a facility. The commission wished to clarify that Chapter 101 does not address permitting, and NSR permits issued under Chapter 116 that involve offsets must be issued with the requirement that offsets be obtained for the life of the permitted facility. This requirement is found in §116.150, New Major Source or Major Modification in Ozone Nonattainment Areas. The banking rules do not modify or supersede that requirement. Chapter 101 does require that new facilities which are subject to Division 3 obtain allowances on an annual basis equal to their actual $NO_x$ emissions in addition to obtaining offsets for the ratio portion of their allowable emissions. The commission also wishes to clarify that allowances which are obtained by these new facilities are not issued by the state, but are obtained from the existing number of allowances available to existing facilities. The total number of allowances under the cap remains finite.

BASF, BCCAAG, Enterprise, and TIP commented that a mechanism should be incorporated into the rules to allow facilities without ESADs to opt into the $NO_x$ cap and trade program.

The commission is not revising the rules in response to these comments. Emission reductions from non-ESAD facilities can be certified and banked as DERCs, which can then be converted and used as allowances. The executive director is evaluating the addition of a provision allowing voluntary participation by non-ESAD facilities in the cap and trade program and may make a recommendation to the commission on the need for future rulemaking.

## SUBCHAPTER A. GENERAL RULES

### 30 TAC §101.1

STATUTORY AUTHORITY

The amendment is adopted under Texas Health and Safety Code, Texas Clean Air Act (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.

*§101.1. Definitions.*

Unless specifically defined in the TCAA or in the rules of the 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.

(1) Account -- For those sources required to be permitted under Chapter 122 of this title (relating to Federal Operating Permits), all sources which are aggregated as a site. For all other sources, any combination of sources under common ownership or control and located on one or more contiguous properties, or properties contiguous except for intervening roads, railroads, rights-of-way, waterways, or similar divisions.

(2) Acid gas flare -- A flare used exclusively for the incineration of hydrogen sulfide and other acidic gases derived from natural gas sweetening processes.

(3) Ambient air -- That portion of the atmosphere, external to buildings, to which the general public has access.

(4) Background -- Background concentration, the level of air contaminants that cannot be reduced by controlling emissions from man-made sources. It is determined by measuring levels in non-urban areas.

(5) Capture system -- All equipment (including, but not limited to, hoods, ducts, fans, booths, ovens, dryers, etc.) that contains, collects, and transports an air pollutant to a control device.

(6) Captured facility -- A manufacturing or production facility that generates an industrial solid waste or hazardous waste that is routinely stored, processed, or disposed of on a shared basis in an integrated waste management unit owned, operated by, and located within a contiguous manufacturing complex.

(7) Carbon adsorber -- An add-on control device which uses activated carbon to adsorb volatile organic compounds (VOC) from a gas stream.

(8) Carbon adsorption system -- A carbon adsorber with an inlet and outlet for exhaust gases and a system to regenerate the saturated adsorbent.

(9) Coating -- A material applied onto or impregnated into a substrate for protective, decorative, or functional purposes. Such materials include, but are not limited to, paints, varnishes, sealants, adhesives, thinners, diluents, inks, maskants, and temporary protective coatings.

(10) Cold solvent cleaning -- A batch process that uses liquid solvent to remove soils from the surfaces of metal parts or to dry the parts by spraying, brushing, flushing, and/or immersion while maintaining the solvent below its boiling point. Wipe cleaning (hand cleaning) is not included in this definition.

(11) Combustion unit -- Any boiler plant, furnace, incinerator, flare, engine, or other device or system used to oxidize solid, liquid, or gaseous fuels, but excluding motors and engines used in propelling land, water, and air vehicles.

(12) Commercial hazardous waste management facility -- Any hazardous waste management facility that accepts hazardous waste or polychlorinated biphenyl compounds for a charge, except a captured facility which disposes only waste generated on-site or a facility that accepts waste only from other facilities owned or effectively controlled by the same person.

(13) Commercial incinerator -- An incinerator used to dispose of waste material from retail and wholesale trade establishments. (See incinerator.)

(14) Commercial medical waste incinerator -- A facility that accepts for incineration medical waste generated outside the property boundaries of the facility.

(15) Component -- A piece of equipment, including, but not limited to, pumps, valves, compressors, and pressure relief valves, which has the potential to leak VOCs.

(16) Condensate -- Liquids that result from the cooling and/or pressure changes of produced natural gas. Once these liquids are processed at gas plants or refineries or in any other manner, they are no longer considered condensates.

(17) Construction-demolition waste -- Waste resulting from construction or demolition projects.

(18) Control system or control device -- Any part, chemical, machine, equipment, contrivance, or combination of same, used to destroy, eliminate, reduce, or control the emission of air contaminants to the atmosphere.

(19) Conveyorized degreasing -- A solvent cleaning process that uses an automated parts handling system, typically a conveyor, to automatically provide a continuous supply of metal parts to be cleaned or dried using either cold solvent or vaporized solvent. A conveyorized degreasing process is fully enclosed except for the conveyor inlet and exit portals.

(20) Criteria Pollutant or Standard -- Any pollutant for which there is a National Ambient Air Quality Standard established under 40 Code of Federal Regulations (CFR) Part 50.

(21) Custody transfer -- The transfer of produced crude oil and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

(22) De minimis impact -- A change in ground level concentration of an air contaminant as a result of the operation of any new major stationary source or of the operation of any existing source which has undergone a major modification, which does not exceed the following specified amounts.

Figure: 30 TAC §101.1(22) (No change.)

(23) Domestic wastes -- The garbage and rubbish normally resulting from the functions of life within a residence.

(24) Emissions banking -- A system for recording emissions reduction credits so they may be used or transferred for future use.

(25) Emissions reduction credit (ERC) -- Any stationary source emissions reduction which has been banked in accordance with Chapter 101, Subchapter H, Division 1 of this title (relating to Emission Credit Banking and Trading).

(26) Emissions reduction credit certificate -- The certificate issued by the executive director which indicates the amount of qualified reduction available for use as offsets and the length of time the reduction is eligible for use.

(27) Emissions unit -- Any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the FCAA.

(28) Exempt solvent -- Those carbon compounds or mixtures of carbon compounds used as solvents which have been excluded from the definition of volatile organic compound.

(29) 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.

(30) Federal motor vehicle regulation -- Control of Air Pollution from Motor Vehicles and Motor Vehicle Engines, 40 CFR Part 85.

(31) Federally enforceable -- All limitations and conditions which are enforceable by the EPA administrator, including those requirements developed under 40 CFR Parts 60 and 61, requirements within any applicable state implementation plan (SIP), any permit requirements established under 40 CFR §52.21 or under regulations approved pursuant to 40 CFR Part 51, Subpart I, including operating permits issued under the approved program that is incorporated into the SIP and that expressly requires adherence to any permit issued under such program.

(32) Flare -- An open combustion unit (i.e., lacking an enclosed combustion chamber) whose combustion air is provided by uncontrolled ambient air around the flame, and which is used as a control device. A flare may be equipped with a radiant heat shield (with or without a refractory lining), but is not equipped with a flame air control damping system to control the air/fuel mixture. In addition, a flare may also use auxiliary fuel. The combustion flame may be elevated or at ground level. A vapor combustor is not considered a flare.

(33) Fuel oil -- Any oil meeting The American Society for Testing and Materials (ASTM) specifications for fuel oil in ASTM D 396-86, Standard Specifications for Fuel Oils. This includes fuel oil grades 1, 2, 4 (Light), 4, 5 (Light), 5 (Heavy), and 6.

(34) Fugitive emission -- Any gaseous or particulate contaminant 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.

(35) Garbage -- Solid waste consisting of putrescible animal and vegetable waste materials resulting from the handling, preparation, cooking, and consumption of food, including waste materials from markets, storage facilities, and handling and sale of produce and other food products.

(36) Gasoline -- Any petroleum distillate having a Reid Vapor Pressure (RVP) of four pounds per square inch (27.6 kPa) or greater which is produced for use as a motor fuel and is commonly called gasoline.

(37) Hazardous waste management facility -- All contiguous land, including structures, appurtenances, and other improvements on the land, used for processing, storing, or disposing of hazardous waste. The term includes a publicly or privately owned hazardous waste management facility consisting of processing, storage, or disposal operational hazardous waste management units such as one or more landfills, surface impoundments, waste piles, incinerators, boilers, and industrial furnaces, including cement kilns, injection wells, salt dome waste containment caverns, land treatment facilities, or a combination of units.

(38) Hazardous waste management unit -- A landfill, surface impoundment, waste pile, boiler, industrial furnace, incinerator, cement kiln, injection well, container, drum, salt dome waste containment cavern, or land treatment unit, or any other structure, vessel, appurtenance, or other improvement on land used to manage hazardous waste.

(39) Hazardous wastes -- Any solid waste identified or listed as a hazardous waste by the administrator of the EPA under the federal Solid Waste Disposal Act, as amended by RCRA, 42 United States Code (USC), §§6901 et seq., as amended.

(40) Heatset (used in offset lithographic printing) -- Any operation where heat is required to evaporate ink oil from the printing ink. Hot air dryers are used to deliver the heat.

(41) High-bake coatings -- Coatings designed to cure at temperatures above 194 degrees Fahrenheit.

(42) High-volume low-pressure (HVLP) spray guns -- Equipment used to apply coatings by means of a spray gun which operates between 0.1 and 10.0 pounds per square inch gauge air pressure.

(43) Incinerator -- An enclosed combustion apparatus and attachments which is used in the process of burning wastes for the primary purpose of reducing its volume and weight by removing the combustibles of the waste and which is equipped with a flue for conducting products of combustion to the atmosphere. Any combustion device which burns 10% or more of solid waste on a total British thermal unit (Btu) heat input basis averaged over any one-hour period shall be considered an incinerator. A combustion device without instrumentation or methodology to determine hourly flow rates of solid waste and burning 1.0% or more of solid waste on a total Btu heat input basis averaged annually shall also be considered an incinerator. An open-trench type (with closed ends) combustion unit may be considered an incinerator when approved by the executive director. Devices burning untreated wood scraps, waste wood, or sludge from the treatment of wastewater from the process mills as a primary fuel for heat recovery are not included under this definition. Combustion devices permitted under this title as combustion devices other than incinerators will not be considered incinerators for application of any regulations within this title provided they are installed and operated in compliance with the condition of all applicable permits.

(44) Industrial boiler -- A boiler located on the site of a facility engaged in a manufacturing process where substances are transformed into new products, including the component parts of products, by mechanical or chemical processes.

(45) Industrial furnace -- Cement kilns, lime kilns, aggregate kilns, phosphate kilns, coke ovens, blast furnaces, smelting, melting, or refining furnaces, including pyrometallurgical devices such as cupolas, reverberator furnaces, sintering machines, roasters, or foundry furnaces, titanium dioxide chloride process oxidation reactors, methane reforming furnaces, pulping recovery furnaces, combustion devices used in the recovery of sulfur values from spent sulfuric acid, and other devices the commission may list.

(46) Industrial solid waste -- Solid waste resulting from, or incidental to, any process of industry or manufacturing, or mining or agricultural operations, classified as follows.

(A) Class 1 industrial solid waste or Class 1 waste is any industrial solid waste designated as Class 1 by the executive director as any industrial solid waste or mixture of industrial solid wastes that because of its concentration or physical or chemical characteristics is toxic, corrosive, flammable, a strong sensitizer or irritant, a generator of sudden pressure by decomposition, heat, or other means, and may pose a substantial present or potential danger to human health or the environment when improperly processed, stored, transported, or otherwise managed, including hazardous industrial waste, as defined in §335.1 of this title (relating to Definitions) and §335.505 of this title (relating to Class 1 Waste Determination).

(B) Class 2 industrial solid waste is any individual solid waste or combination of industrial solid wastes that cannot be described as Class 1 or Class 3, as defined in §335.506 of this title (relating to Class 2 Waste Determination).

(C) Class 3 industrial solid waste is any inert and essentially insoluble industrial solid waste, including materials such as rock, brick, glass, dirt, and certain plastics and rubber, etc., that are not readily decomposable as defined in §335.507 of this title (relating to Class 3 Waste Determination).

(47) 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.

(48) Leak -- A VOC concentration greater than 10,000 parts per million by volume (ppmv) or the amount specified by applicable rule, whichever is lower; or the dripping or exuding of process fluid based on sight, smell, or sound.

(49) Liquid fuel -- A liquid combustible mixture, not derived from hazardous waste, with a heating value of at least 5,000 Btu per pound.

(50) Liquid-mounted seal -- A primary seal mounted in continuous contact with the liquid between the tank wall and the floating roof around the circumference of the tank.

(51) Maintenance area -- A geographic region of the state previously designated nonattainment under the FCAA Amendments of 1990 and subsequently redesignated to attainment subject to the requirement to develop a maintenance plan under FCAA, §175A, as amended. The following are the maintenance areas within the state: Victoria Ozone Maintenance Area (60 FR 12453) - Victoria County.

(52) Maintenance Plan -- A revision to the applicable SIP, meeting the requirements of FCAA, §175A.

(53) Marine vessel -- Any watercraft used, or capable of being used, as a means of transportation on water, and that is constructed or adapted to carry, or that carries, oil, gasoline, or other volatile organic liquid in bulk as a cargo or cargo residue.

(54) Mechanical shoe seal -- A metal sheet which is held vertically against the storage tank wall by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(55) Medical waste -- Waste materials identified by the Texas Department of Health as "special waste from health care-related facilities" and those waste materials commingled and discarded with special waste from health care related facilities.

(56) Metropolitan Planning Organization (MPO) -- That organization designated as being responsible, together with the state, for conducting the continuing, cooperative, and comprehensive planning process under 23 USC, §134 and 49 USC, §1607.

(57) Mobile emissions reduction credit (MERC) -- The credit obtained from an enforceable, permanent, quantifiable, and surplus (to other federal and state regulations) emissions reduction generated by a mobile source as set forth in Chapter 114, Subchapter E of this title (relating to Low Emission Vehicle Fleet Requirements) or Chapter 114, Subchapter F of this title (relating to Vehicle Retirement and Mobile Emission Reduction Credits), and which has been banked in accordance with Chapter 101, Subchapter H, Division 1 of this title.

(58) Motor vehicle -- A self propelled vehicle designed for transporting persons or property on a street or highway.

(59) Motor vehicle fuel dispensing facility -- Any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

(60) Municipal solid waste -- Solid waste resulting from, or incidental to, municipal, community, commercial, institutional, and recreational activities, including garbage, rubbish, ashes, street cleanings, dead animals, abandoned automobiles, and all other solid waste except industrial solid waste.

(61) Municipal solid waste facility -- All contiguous land, structures, other appurtenances, and improvements on the land used for processing, storing, or disposing of solid waste. A facility may be publicly or privately owned and may consist of several processing, storage, or disposal operational units, e.g., one or more landfills, surface impoundments, or combinations of them.

(62) Municipal solid waste landfill -- A discrete area of land or an excavation that receives household waste and that is not a land application unit, surface impoundment, injection well, or waste pile, as those terms are defined under 40 CFR §257.2. A municipal solid waste landfill (MSWLF) unit also may receive other types of RCRA Subtitle D wastes, such as commercial solid waste, non-hazardous sludge, conditionally exempt small-quantity generator waste, and industrial solid waste. Such a landfill may be publicly or privately owned. An MSWLF unit may be a new MSWLF unit, an existing MSWLF unit, or a lateral expansion.

(63) National Ambient Air Quality Standard (NAAQS) -- Those standards established under FCAA, §109, including standards for carbon monoxide (CO), lead (Pb), nitrogen dioxide ($NO_2$), ozone ($O_3$), inhalable particulate matter ($PM_{10}$ and $PM_{2.5}$), and sulfur dioxide ($SO_2$).

(64) Net ground-level concentration -- The concentration of an air contaminant as measured at or beyond the property boundary minus the representative concentration flowing onto a property as measured at any point. Where there is no expected influence of the air contaminant flowing onto a property from other sources, the net ground level concentration may be determined by a measurement at or beyond the property boundary.

(65) New source -- Any stationary source, the construction or modification of which was commenced after March 5, 1972.

(66) Nonattainment area -- A defined region within the state which is designated by EPA as failing to meet the National Ambient Air Quality Standard for a pollutant for which a standard exists. The EPA will designate the area as nonattainment under the provisions of FCAA, §107(d). For the official list and boundaries of nonattainment areas, see 40 CFR Part 81 and pertinent Federal Register notices. The following areas comprise the nonattainment areas within the state:

(A) Carbon monoxide (CO). El Paso (ELP) CO nonattainment area (56 FR 56694)--Classified as a Moderate CO nonattainment area with a design value less than or equal to 12.7 parts per million. Portion of El Paso County. Portion of the city limits of El Paso: That portion of the City of El Paso bounded on the north by Highway 10 from Porfirio Diaz Street to Raynolds Street, Raynolds Street from Highway 10 to the Southern Pacific Railroad lines, the Southern Pacific Railroad lines from Raynolds Street to Highway 62, Highway 62 from the Southern Pacific Railroad lines to Highway 20, and Highway 20 from Highway 62 to Polo Inn Road. Bounded on the east by Polo Inn Road from Highway 20 to the Texas-Mexico border. Bounded on the south by the Texas-Mexico border from Polo Inn Road to Porfirio Diaz Street. Bounded on the west by Porfirio Diaz Street from the Texas-Mexico border to Highway 10.

(B) Inhalable particulate matter ($PM_{10}$). El Paso (ELP) $PM_{10}$ nonattainment area (56 FR 56694)--Classified as a Moderate $PM_{10}$ nonattainment area. Portion of El Paso County which comprises the El Paso city limit boundaries as they existed on November 15, 1990.

(C) Lead. Collin County lead nonattainment area (56 FR 56694)--Portion of Collin County. Eastside: Starting at the intersection of south Fifth Street and the fence line approximately 1,000 feet south of the Gould National Batteries (GNB) property line going north to the intersection of south Fifth Street and Eubanks Street; Northside: Proceeding west on Eubanks to the Burlington Railroad tracks; Westside: Along the Burlington Railroad tracks to the fence line approximately 1,000 feet south of the GNB property line; Southside: Fence line approximately 1,000 feet south of the GNB property line.

(D) Nitrogen Dioxide ($NO_2$). No designated nonattainment areas.

(E) Ozone.

*(i)* Houston/Galveston (HGA) ozone nonattainment area (56 FR 56694)--Classified as a Severe-17 ozone nonattainment area. Consists of Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties.

*(ii)* El Paso (ELP) ozone nonattainment area (56 FR 56694)--Classified as a Serious ozone nonattainment area. Consists of El Paso County.

*(iii)* Beaumont/Port Arthur (BPA) ozone nonattainment area (61 FR 14496)--Classified as a Moderate ozone nonattainment area. Consists of Hardin, Jefferson, and Orange Counties.

*(iv)* Dallas/Fort Worth (DFW) ozone nonattainment area (63 FR 8128)--Classified as a Serious ozone nonattainment area. Consists of Collin, Dallas, Denton, and Tarrant Counties.

(F) Sulfur Dioxide ($SO_2$). No designated nonattainment areas.

(67) Nonreportable upset -- Any upset that is not a reportable upset as defined in this section.

(68) Opacity -- The degree to which an emission of air contaminants obstructs the transmission of light expressed as the percentage of light obstructed as measured by an optical instrument or trained observer.

(69) Open-top vapor degreasing -- A batch solvent cleaning process that is open to the air and which uses boiling solvent to create solvent vapor used to clean or dry metal parts through condensation of the hot solvent vapors on the colder metal parts.

(70) Outdoor burning -- Any fire or smoke-producing process which is not conducted in a combustion unit.

(71) Particulate matter -- Any material, except uncombined water, that exists as a solid or liquid in the atmosphere or in a gas stream at standard conditions.

(72) Particulate matter emissions -- All finely-divided solid or liquid material, other than uncombined water, emitted to the ambient air as measured by EPA Reference Method 5, as specified at 40 CFR Part 60, Appendix A, modified to include particulate caught by impinger train; by an equivalent or alternative method, as specified at 40 CFR Part 51; or by a test method specified in an approved SIP.

(73) 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.

(74) $PM_{10}$ -- Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers as measured by a reference method based on 40 CFR Part 50, Appendix J and designated in accordance with 40 CFR Part 53, or by an equivalent method designated with that Part 53.

(75) $PM_{10}$ emissions -- Finely-divided solid or liquid material with an aerodynamic diameter less than or equal to a nominal ten micrometers emitted to the ambient air as measured by an applicable reference method, or an equivalent or alternative method specified in 40 CFR Part 51, or by a test method specified in an approved SIP.

(76) Polychlorinated biphenyl compound (PCB) -- A compound subject to 40 CFR Part 761.

(77) Process or processes -- Any action, operation, or treatment embracing chemical, commercial, industrial, or manufacturing factors such as combustion units, kilns, stills, dryers, roasters, and equipment used in connection therewith, and all other methods or forms of manufacturing or processing that may emit smoke, particulate matter, gaseous matter, or visible emissions.

(78) Process weight per hour -- "Process weight" is the total weight of all materials introduced or recirculated into any specific process which may cause any discharge of air contaminants into the atmosphere. Solid fuels charged into the process will be considered as part of the process weight, but liquid and gaseous fuels and combustion air will not. The "process weight per hour" will be derived by dividing the total process weight by the number of hours in one complete operation from the beginning of any given process to the completion thereof, excluding any time during which the equipment used to conduct the process is idle. For continuous operation, the "process weight per hour" will be derived by dividing the total process weight for a 24-hour period by 24.

(79) Property -- All land under common control or ownership coupled with all improvements on such land, and all fixed or movable objects on such land, or any vessel on the waters of this state.

(80) Reasonable further progress (RFP) -- Annual incremental reductions in emissions of the applicable air contaminant which are sufficient to provide for attainment of the applicable national ambient air quality standard in the designated nonattainment areas by the date required in the SIP.

(81) Remote reservoir cold solvent cleaning -- Any cold solvent cleaning operation in which liquid solvent is pumped to a sink-like work area that drains solvent back into an enclosed container while parts are being cleaned, allowing no solvent to pool in the work area.

(82) Reportable quantity (RQ) -- Is as follows:

(A) for individual air contaminant compounds and specifically listed mixtures, either:

*(i)* the lowest of the quantities:

*(I)* listed in 40 CFR §302, Table 302.4, the column "final RQ";

*(II)* listed in 40 CFR §355, Appendix A, the column "Reportable Quantity"; or

*(III)* listed as follows:

(-a-) butanes (any isomer)--5,000 pounds;
(-b-) butenes (any isomer, except 1,3-butadiene)--5,000 pounds;
(-c-) ethylene--5,000 pounds;
(-d-) carbon monoxide--5,000 pounds;
(-e-) pentanes (any isomer)--5,000 pounds;
(-f-) propane--5,000 pounds;
(-g-) propylene--5,000 pounds;
(-h-) ethanol--5,000 pounds;
(-i-) isopropyl alcohol--5,000 pounds;
(-j-) mineral spirits--5,000 pounds;
(-k-) hexanes (any isomer)--5,000 pounds;
(-l-) octanes (any isomer)--5,000 pounds;
(-m-) decanes (any isomer)--5,000 pounds; or

*(ii)* if not listed in clause (i) of this subparagraph, 100 pounds;

(B) for mixtures of air contaminant compounds:

*(i)* where the relative amount of individual air contaminant compounds is known through common process knowledge or prior engineering analysis or testing, any amount of an individual air contaminant compound which equals or exceeds the amount specified in subparagraph (A) of this paragraph;

*(ii)* where the relative amount of individual air contaminant compounds in subparagraph (A)(i) of this paragraph is not known, any amount of the mixture which equals or exceeds the amount for any single air contaminant compound that is present in the mixture and listed in subparagraph (A)(i) of this paragraph;

*(iii)* where each of the individual air contaminant compounds listed in subparagraph (A)(i) of this paragraph are known to be less than 0.02% by weight of the mixture, and each of the other individual air contaminant compounds covered by subparagraph (A)(ii) of this paragraph are known to be less than 2.0% by weight of the mixture, any total amount of the mixture of air contaminant compounds greater than or equal to 5,000 pounds; or

(iv) where natural gas excluding methane and ethane, or air emissions from crude oil are known to be in an amount greater than or equal to 5,000 pounds or associated hydrogen sulfide and mercaptans in a total amount greater than 100 pounds, whichever occurs first;

(C) for opacity, an opacity which is equal to or exceeds 15 additional percentage points above the applicable limit, averaged over a six-minute period. Opacity is the only reportable quantity applicable to boilers or combustion turbines fueled by natural gas, coal, lignite, wood, or fuel oil containing hazardous air pollutants at a concentration of less than 0.02% by weight;

(D) for facilities where air contaminant compounds are measured directly by a continuous emission monitoring system providing updated readings at a minimum 15-minute interval an amount, approved by the executive director based on any relevant conditions and a screening model, that would be reported prior to ground level concentrations reaching at any distance beyond the closest facility property line:

*(i)* less than one half of any applicable ambient air standards; and

*(ii)* less than two times the concentration of applicable air emission limitations.

(83) Reportable upset -- Any upset which, in any 24-hour period, results in an unauthorized emission of air contaminants equal to or in excess of the reportable quantity as defined in this section.

(84) Rubbish -- Nonputrescible solid waste, consisting of both combustible and noncombustible waste materials. Combustible rubbish includes paper, rags, cartons, wood, excelsior, furniture, rubber, plastics, yard trimmings, leaves, and similar materials. Noncombustible rubbish includes glass, crockery, tin cans, aluminum cans, metal furniture, and like materials which will not burn at ordinary incinerator temperatures (1,600 degrees Fahrenheit to 1,800 degrees Fahrenheit).

(85) Sludge -- Any solid or semi-solid, or liquid waste generated from a municipal, commercial, or industrial wastewater treatment plant; water supply treatment plant, exclusive of the treated effluent from a wastewater treatment plant; or air pollution control equipment.

(86) Smoke -- Small gas-born particles resulting from incomplete combustion consisting predominately of carbon and other combustible material and present in sufficient quantity to be visible.

(87) Solid waste -- Garbage, rubbish, refuse, sludge from a waste water treatment plant, water supply treatment plant, or air pollution control equipment, and other discarded material, including solid, liquid, semisolid, or containerized gaseous material resulting from industrial, municipal, commercial, mining, and agricultural operations and from community and institutional activities. The term does not include:

(A) solid or dissolved material in domestic sewage, or solid or dissolved material in irrigation return flows, or industrial discharges subject to regulation by permit issued under the Texas Water Code, Chapter 26;

(B) soil, dirt, rock, sand, and other natural or man-made inert solid materials used to fill land, if the object of the fill is to make the land suitable for the construction of surface improvements; or

(C) waste materials that result from activities associated with the exploration, development, or production of oil or gas, or geothermal resources, and other substance or material regulated by the Railroad Commission of Texas under the Natural Resources Code, §91.101, unless the waste, substance, or material results from activities associated with gasoline plants, natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants and is hazardous waste as defined by the administrator of the EPA under the federal Solid Waste Disposal Act, as amended by RCRA, as amended (42 USC, §§6901 et seq.).

(88) Sour crude -- A crude oil which will emit a sour gas when in equilibrium at atmospheric pressure.

(89) Sour gas -- Any natural gas containing more than 1.5 grains of hydrogen sulfide per 100 cubic feet, or more than 30 grains of total sulfur per 100 cubic feet.

(90) Source -- 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.

(91) Special waste from health care related facilities -- A solid waste which if improperly treated or handled may serve to transmit infectious disease(s) and which is comprised of the following: animal waste, bulk blood and blood products, microbiological waste, pathological waste, and sharps.

(92) Standard conditions -- A condition at a temperature of 68 degrees Fahrenheit (20 degrees Centigrade) and a pressure of 14.7 pounds per square inch absolute (101.3 kPa). Pollutant concentrations from an incinerator will be corrected to a condition of 50% excess air if the incinerator is operating at greater than 50% excess air.

(93) Standard metropolitan statistical area -- An area consisting of a county or one or more contiguous counties which is officially so designated by the United States Bureau of the Budget.

(94) Submerged fill pipe -- A fill pipe that extends from the top of a tank to have a maximum clearance of six inches (15.2 cm) from the bottom or, when applied to a tank which is loaded from the side, that has a discharge opening entirely submerged when the pipe used to withdraw liquid from the tank can no longer withdraw liquid in normal operation.

(95) Sulfur compounds -- All inorganic or organic chemicals having an atom or atoms of sulfur in their chemical structure.

(96) Sulfuric acid mist/sulfuric acid -- Emissions of sulfuric acid mist and sulfuric acid are considered to be the same air contaminant calculated as $H_2SO_4$ and shall include sulfuric acid liquid mist, sulfur trioxide, and sulfuric acid vapor as measured by Test Method 8 in 40 CFR Part 60, Appendix A.

(97) Sweet crude oil and gas -- Those crude petroleum hydrocarbons that are not "sour" as defined in this section.

(98) Total suspended particulate -- Particulate matter as measured by the method described in 40 CFR Part 50, Appendix B.

(99) Transfer efficiency -- The amount of coating solids deposited onto the surface or a part of product divided by the total amount of coating solids delivered to the coating application system.

(100) True vapor pressure -- The absolute aggregate partial vapor pressure (psia) of all VOCs at the temperature of storage, handling, or processing.

(101) Unauthorized emission -- An emission of any air contaminant except carbon dioxide, water, nitrogen, methane, ethane, noble gases, hydrogen, and oxygen which exceeds any air emission

limitation in a permit, rule, or order of the commission or as authorized by TCAA, §382.0518(g).

(102) Upset -- An unscheduled occurrence or excursion of a process or operation that results in an unauthorized emission of air contaminants.

(103) Utility boiler -- A boiler used to produce electric power, steam, or heated or cooled air, or other gases or fluids for sale.

(104) Vapor combustor -- A partially enclosed combustion device used to destroy VOCs by smokeless combustion without extracting energy in the form of process heat or steam. The combustion flame may be partially visible, but at no time does the device operate with an uncontrolled flame. Auxiliary fuel and/or a flame air control damping system, which can operate at all times to control the air/fuel mixture to the combustor's flame zone, may be required to ensure smokeless combustion during operation.

(105) Vapor-mounted seal -- A primary seal mounted so there is an annular space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the tank wall, the liquid surface, and the floating roof or cover.

(106) Vent -- Any duct, stack, chimney, flue, conduit, or other device used to conduct air contaminants into the atmosphere.

(107) Visible emissions -- Particulate or gaseous matter which can be detected by the human eye. The radiant energy from an open flame shall not be considered a visible emission under this definition.

(108) Volatile organic compound (VOC) -- Any compound of carbon or mixture of carbon compounds excluding methane; ethane; 1,1,1-trichloroethane (methyl chloroform); methylene chloride (dichloromethane); perchloroethylene (tetrachloroethylene); trichlorofluoromethane (CFC-11); dichlorodifluoromethane (CFC-12); chlorodifluoromethane (HCFC-22); trifluoromethane (HFC-23); 1,1,2-trichloro-1,2,2-trifluoroethane (CFC-113); 1,2-dichloro-1,1,2,2-tetrafluoroethane (CFC-114); chloropentafluoroethane (CFC-115); 1,1,1-trifluoro-2,2-dichloroethane (HCFC-123); 2-chloro-1,1,1,2-tetrafluoroethane (HCFC-124); pentafluoroethane (HFC-125); 1,1,2,2-tetrafluoroethane (HFC-134); 1,1,1,2-tetrafluoroethane (HFC-134a); 1,1-dichloro-1-fluoroethane (HCFC-141b); 1-chloro-1,1-difluoroethane (HCFC-142b); 1,1,1-trifluoroethane (HFC-143a); 1,1-difluoroethane (HFC-152a); parachlorobenzotrifluoride (PCBTF); cyclic, branched, or linear completely methylated siloxanes; acetone; 3,3-dichloro-1,1,1,2,2-pentafluoropropane (HCFC-225ca); 1,3-dichloro-1,1,2,2,3-pentafluoropropane (HCFC-225cb); 1,1,1,2,3,4,4,5,5,5-decafluoropentane (HFC 43-10mee); difluoromethane (HFC-32); ethylfluoride (HFC-161); 1,1,1,3,3,3-hexafluoropropane (HFC-236fa); 1,1,2,2,3-pentafluoropropane (HFC-245ca); 1,1,2,3,3-pentafluoropropane (HFC-245ea); 1,1,1,2,3-pentafluoropropane (HFC-245eb); 1,1,1,3,3-pentafluoropropane (HFC-245fa); 1,1,1,2,3,3-hexafluoropropane (HFC-236ea); 1,1,1,3,3-pentafluorobutane (HFC-365mfc); chlorofluoromethane (HCFC-31); 1,2-dichloro-1,1,2-trifluoroethane (HCFC-123a); 1-chloro-1-fluoroethane (HCFC-151a); 1,1,1,2,2,3,3,4,4-nonafluoro-4-methoxybutane; 2-(difluoromethoxymethyl)-1,1,1,2,3,3,3-heptafluoropropane; 1-ethoxy-1,1,2,2,3,3,4,4,4-nonafluorobutane; 2-(ethoxydifluoromethyl)-1,1,1,2,3,3,3-heptafluoropropane; methyl acetate; carbon monoxide; carbon dioxide; carbonic acid; metallic carbides or carbonates; ammonium carbonate; and perfluorocarbon compounds which fall into these classes:

(A) cyclic, branched, or linear, completely fluorinated alkanes;

(B) cyclic, branched, or linear, completely fluorinated ethers with no unsaturations;

(C) cyclic, branched, or linear, completely fluorinated tertiary amines with no unsaturations; and

(D) sulfur-containing perfluorocarbons with no unsaturations and with sulfur bonds only to carbon and fluorine.

(109) VOC water separator -- Any tank, box, sump, or other container in which any VOC, floating on or contained in water entering such tank, box, sump, or other container, is physically separated and removed from such water prior to outfall, drainage, or recovery of such water.

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 September 28, 2001.

TRD-200105868
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 18, 2001
Proposal publication date: June 15, 2001
For further information, please call: (512) 239-3048

♦ ♦ ♦

## SUBCHAPTER H. EMISSIONS BANKING AND TRADING
## DIVISION 3. MASS EMISSIONS CAP AND TRADE PROGRAM

### 30 TAC §§101.350, 101.352 - 101.354, 101.356, 101.360, 101.363

STATUTORY AUTHORITY

The amendments and new section 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 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.

*§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) Adjustment period -- A period of time, beginning on the first day of operation of a facility and ending no more than 180 consecutive days later, used to make corrections and adjustments to achieve normal technical operating characteristics of the facility.

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

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

(4) 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."

(5) 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.

(6) 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.

(7) 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.

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

(9) Existing Facility -- A new or modified facility that either has submitted an application for a permit under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) 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 of this title (relating to Permits by Rule) and commenced construction before January 2, 2001.

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

(11) Level of activity -- The amount of activity at a facility measured in terms of production, fuel use, raw materials input, or other similar units.

(12) 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.

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

*§101.353. Allocation of Allowances.*

(a) Allowances will be deposited into compliance accounts according to the following equation except as provided in subsection (b) or (h) 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 (relating to Control of Air Pollution by Permit for New Construction of Modification), 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 (relating to Permits by Rule) 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(g) of this title (relating to Allowance Banking and Trading).

(c) If actual emissions of nitrogen oxides ($NO_x$) during a control period exceed the amount of allowances held in a compliance account on March 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; and

(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) The owner or operator of a facility may, due to extenuating circumstances, request up to two additional calendar years to establish a baseline period more representative of normal operation as determined by the executive director. Applications for extenuating circumstances must be submitted by the owner or operator of the facility to the executive director:

(1) no later than June 30, 2001;

(2) for facilities whose baseline as described variable (2)(C) listed in the figure contained in subsection (a) of this section is not complete by June 30, 2001, no later than 90 days after completion of the baseline period; or

(3) at any time as authorized by the executive director.

(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 monitoring and testing protocols established in §§117.114, 117.214, and 117.479 of this title (relating to Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration; and Monitoring, Recordkeeping, and Reporting Requirements).

(b) In the event that the monitoring and testing data required under subsection (a) of this section is missing or unavailable, the facility may report actual emissions for that period of time using the following equation or other listed methods in the following order to determine actual emissions: continuous monitoring data; periodic monitoring data; testing data; manufacturer's data; and *EPA Compilation of Air Pollution Emission Factors* (AP-42). When reporting actual emissions as required under this subsection, the facility must also submit the justification for not using the methods in subsection (a) of this section and the justification for the method used.
Figure: 30 TAC §101.354(b)

(c) If the protocol used to show compliance with this section differs from the protocol used by the commission to establish the allocation of allowances under §101.353 of this title (relating to Allocation of Allowances), the executive director may recalculate the number of allowances allocated per year for consistency between the methods.

(d) 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.

(e) 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.

(f) On March 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 nitrogen oxides 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 (d) of this section.

(c) The owner or operator of a site receiving allowances on an annual basis may permanently sell those rights to any person. This request for transfer of ownership shall be completed by the executive director following the submission of a completed ECT-4 Form, Application for Permanent Transfer of Allowance Ownership. The executive director will issue a letter to the purchaser and seller reflecting this transaction. The transaction will be considered finalized upon issuance of this letter.

(d) Allowances not used for compliance during a control period which were allocated in accordance with the variables in (2)(B) and (3)(B) listed in the figure contained in §101.353(a) of this title (relating to Allocation of Allowances) may not be banked for future use or traded.

(e) Only authorized account representatives may trade allowances.

(f) Trades will be reviewed for approval 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.

(g) 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) - (9) 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) - (9) of this subsection provided that 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, 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) DERCs generated prior to January 1, 2005 may be used in lieu of allowances for compliance with this division for the control period beginning January 1, 2005 through December 31, 2005 at a ratio of four DERCs for one allowance.

(4) DERCs generated prior to January 1, 2005 may be used in lieu of allowances for compliance with this division for the control period beginning January 1, 2006 through December 31, 2006 at a ratio of seven DERCs for one allowance.

(5) DERCs generated prior to January 1, 2005 may be used in lieu of allowances for compliance with this division for the control period beginning January 1, 2007 and all subsequent control periods at a ratio of ten DERCs for one allowance.

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

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

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

(9) 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.

(h) Emission reduction credits (ERCs) may be converted into a yearly allocation of allowances at the rate of one ERC to one allowance per year only if they were generated prior to December 1, 2000 and provided that:

(1) the ERC is quantifiable, real, surplus, enforceable, and permanent as required in §101.302 of this title (relating to General Provisions) at the time the ERC is converted;

(2) the ERC was generated in the HGA area;

(3) the ERC was generated from a reduction in $NO_x$;

(4) the ERC has not expired; and

(5) the owner of the ERC has prior approval from the executive director.

*§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, emission factors, 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 allowable 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 used to determine its baseline activity, the actual level of activity and actual emission factors for those two years 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.

(c) Owners or operators of a site that becomes subject to this division on or after April 1, 2001 by virtue of adding facilities subject to the emission specifications under §§117.106, 117.206, and 117.475 of this title (relating to Emission Specifications for Attainment Demonstrations; and Emission Specifications) shall certify the level of activity for existing facilities in accordance with subsections (a) and (b) of this section, except such certification shall be submitted no later than 90 days from the date the site becomes subject to this division, as determined by the executive director.

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 September 28, 2001.

TRD-200105869
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 18, 2001
Proposal publication date: June 15, 2001
For further information, please call: (512) 239-0348

♦ ♦ ♦

## DIVISION 4. DISCRETE EMISSION CREDIT BANKING AND TRADING

### 30 TAC §§101.370, 101.372, 101.373

STATUTORY AUTHORITY

The amendments 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 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.

*§101.373. Protocols.*

(a) All discrete emission credit source categories must use an 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 shutdown or 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) (No change.)

(A) The amount of DERCs generated must be rounded down to the nearest tenth of a 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 shutdown 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 or withdrawn.

(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(g) of this title (relating to Allowance Banking and Trading).

(D) compliance with §115.950 and §117.570 of this title (relating to Use of Emissions 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 non-road 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) (No change.)

(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) (No change.)

(C) The amount of discrete emission credits needed must be rounded up to the nearest tenth of a 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) Application of intent to use. An application 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 applicant has submitted the notice and received executive director approval;

(2) the application 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 application 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 application 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 application 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.

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 September 28, 2001.

TRD-200105870
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 18, 2001
Proposal publication date: June 15, 2001
For further information, please call: (512) 239-3048

♦ ♦ ♦

# CHAPTER 114. CONTROL OF AIR POLLUTION FROM MOTOR VEHICLES
## SUBCHAPTER H. LOW EMISSION FUELS
## DIVISION 2. LOW EMISSION DIESEL

### 30 TAC §§114.314, 114.318, 114.319

The Texas Natural Resource Conservation Commission (commission) adopts amendments to §114.314, Registration of Diesel Producers and Importers and §114.319, Affected Counties and Compliance Dates; and new §114.318, Alternative Emission Reduction Plan. The commission adopts the amendments and new section to Chapter 114 and corresponding revisions to the state implementation plan (SIP) in order to control ground-level ozone in the Houston/Galveston (HGA) ozone nonattainment area as well as the other affected areas in the state and implement House Bill (HB) 2912, Article 15, of the 77th Legislature, 2001. Sections 114.314, 114.318, and 114.319 are adopted *with changes* to the proposed text as published in the June 15, 2001 issue of the *Texas Register* (26 TexReg 4388).

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 Federal Clean Air Act (FCAA) as codified in 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 §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas, such as HGA. The HGA area, defined as 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 several 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 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 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, the EPA policy regarding SIP elements and timelines went through changes. Two national initiatives in particular resulted in changing deadlines and requirements. The first of these initiatives was a program conducted by 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 the OTAG program, and OTAG 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 was 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, the one-hour 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 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-1999 ROP plan by December 31, 2000; and to perform a mid-course review by May 1, 2004.

The emission reduction requirements included as part of the December 2000 SIP revision represented 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.

A SIP revision for HGA was adopted by the commission on December 6, 2000 and was submitted to the EPA by December 31, 2000. The December 2000 SIP revision contained rules, enforceable commitments, and photochemical modeling analyses in support of the HGA ozone attainment demonstration. In addition, this SIP contained Post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contained 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.

In order for the HGA area to have an approvable attainment demonstration, the EPA 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 HGA ozone nonattainment area will need to ultimately reduce $NO_x$ more than 750 tons per day (tpd) to reach attainment of 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 amendments will contribute to attainment and maintenance of the one-hour ozone standard in the HGA area.

The 77th Legislature, 2001, passed HB 2912, Article 15, which amended Texas Clean Air Act (TCAA), §382.039(g) - (i). Subsection (g) was amended to restrict the commission's authority, before January 1, 2004, to regulate the fuel content for clean motor vehicle fuel for any area of the state that is more stringent or restrictive than the EPA standard for that area, except as provided in subsection (h), unless the fuel is specifically authorized by the legislature. New subsection (h) restricts the commission from requiring the distribution of Texas LED as described in revisions to the SIP for control of ozone air pollution prior to February 1, 2005. Subsection (i) allows the commission to consider, as an alternative method of compliance with subsection (h), fuels to achieve equivalent emissions reductions. This rulemaking action implements the changes required by HB 2912, Article 15.

These rules are one element of the control strategy for the HGA Attainment Demonstration SIP that reduce $NO_x$ emissions necessary for the HGA nonattainment area to be able to demonstrate attainment with the ozone NAAQS. Additional benefits will be achieved in the Beaumont/Port Arthur (BPA) and Dallas/Fort Worth (DFW) ozone nonattainment areas, and the 95- county central and eastern Texas region. The purpose of these amendments is to modify the LED air pollution control strategy to provide additional flexibility in the rules to allow for alternative emission reduction plans; to delay the implementation date from May 1, 2002 to April 1, 2005 to allow producers sufficient time to complete refinery modifications to comply with the LED requirements; and to reduce the coverage area of the rules from statewide to those counties that have previously been included in the regional air pollution control strategy for the HGA nonattainment area.

These amendments to the LED rules would no longer require LED for on-road use statewide, but would continue to require LED fuel for both on-road and non-road use in the eight-county HGA ozone nonattainment area; the four-county DFW ozone nonattainment area, which includes Collin, Dallas, Denton, and Tarrant Counties; the three-county BPA ozone nonattainment area, which includes Hardin, Jefferson, and Orange Counties; and 95 additional central and eastern Texas counties, which include 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 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 affected areas meets the specifications stated in these rules. The amendments and new section delay the LED requirements from May 1, 2002 until April 1, 2005. The requirements specify that diesel fuel produced for delivery and ultimate sale to the consumer (which may ultimately be used to power a diesel fueled compression-ignition engine in a motor vehicle or in non-road equipment in the affected counties) does 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.

The LED fuel ozone control strategy requires diesel fuel content limits more restrictive than federal diesel fuel regulations. The current federal regulations governing diesel fuel quality are found 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). Section 80.29 establishes 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 recently adopted federal regulations governing diesel fuel quality in 40 CFR §80.520 (What are the standards and dye requirements for motor vehicle diesel fuel?) will limit on-road diesel sulfur to 15 ppm beginning June 1, 2006. The state's adopted LED regulations limit both on-road and non-road diesel to 500 ppm sulfur, 10% aromatic hydrocarbons, and a 48 cetane minimum in the HGA, DFW, BPA ozone nonattainment areas and 95 central and eastern Texas counties in 2005 and further limits on-road and non-road diesel sulfur to 15 ppm in the coverage area in 2006. However, 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 the authority to place controls on the fuel content of non-road diesel fuel. 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. The commission does not believe that a waiver is needed for the non-road portion of these rules.

Modeling performed for the commission assessing the benefits of this $NO_x$ emission reduction strategy demonstrated that significant emission reductions could be achieved from 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 $NO_x$ emissions from on-road vehicles and non-road equipment in the regional coverage area by 16.32 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 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 regional area 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. The amendments and new section 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 ensuring the ability of the fuel industry to comply with the LED program.

SECTION BY SECTION DISCUSSION

The amendments to §114.314 revise the dates by which producers and importers are required to register from December 1, 2001, or after May 31, 2002 for those entities that begin to produce or import LED after that date, to December 1, 2004 and April 30, 2005 respectively, in order to reflect the changes to the implementation dates in §114.319. Language has been revised to clarify that the April 30, 2005 date is intended to discourage entities from attempting to register after the December 1, 2004 deadline by not allowing entities to produce or import LED in the first 30 days starting April 1, 2005.

The new §114.318 establishes an alternative method of compliance with the requirements of Chapter 114, Division 2, for producers that submit an alternative emission reduction plan by January 2003 which is approved by the executive director and the EPA no later that May 2003. The emission reduction plan must demonstrate the market share the producer supplies, demonstrate the reductions associated with compliance with this division attributable to the market share, specify a substitute fuel strategy that will achieve equivalent reductions, and contain adequate enforcement provisions. This section will allow equivalent emission reductions to be achieved while providing additional flexibility to producers and importers. The section also clarifies that the executive director may consider early reductions in the determination of equivalency. Additionally, the section provides the executive director with some discretion to accept late plans in order to allow, for example, for new producers which come into the market after the deadline. In addition, the compliance dates in the proposed §114.318 were amended at adoption from January 2003 to January 31, 2003; May 2003 to May 31, 2003; and January 2003 to January 31, 2003; respectively, to provide clarification.

The amendments to §114.319 will revise subsection (a) to delay the implementation date from May 1, 2002 to April 1, 2005, and to limit the coverage area to those counties listed in subsection (b). These amendments will allow producers and importers additional time to complete refinery modifications to comply with the LED requirements, but will also implement the LED requirement in sufficient time to achieve the emission reductions needed to demonstrate attainment. The reduction in coverage area will reduce the cost burden upon areas of the state that would not benefit as much from the use of LED as those counties that have previously been included in regional air pollution control strategies for the HGA nonattainment area. Additionally, limiting LED to the central and eastern region of Texas, rather than requiring on-road LED for the whole state, ensures that there will be sufficient clean diesel for areas of the state where it is most needed. The commission has received information from diesel fuel refiners and suppliers in Texas that a state-wide requirement would exceed the capacity of refiners to provide the clean fuel when it is required, creating the possibility that adequate LED would not be available to achieve the anticipated emission reductions. In addition, §114.319 was amended at adoption to make minor editorial changes.

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 is not subject to §2001.0225 because it does not meet the definition of a "major environmental rule" as defined in that statute. A "major environmental rule" is 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 but will not 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 provide flexibility in the 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. Additionally, §2001.0225 only applies 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.

This rulemaking action does not meet any of these four applicability requirements. Specifically, the LED fuel requirements including 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. 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. While §7410 does not require specific programs, methods, or reductions in order to meet the standard, 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. Thus, while specific measures are not generally required, the emission reductions are required. States are not free to ignore the requirements of §7410 and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule.

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, 1997. 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 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. For these reasons, rules proposed for inclusion in the SIP fall under 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 reductions, such as those 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 obtain $NO_x$ 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 NAAQS established under federal law and authorized under TCAA, §§382.011, 382.012, 382.017, 382.019, 382.037(g) - (i), and 382.039.

The commission invited public comment on the draft RIA determination, and received comments which are addressed in the RESPONSE TO COMMENTS section of this preamble.

TAKINGS IMPACT ASSESSMENT

The commission prepared a takings impact assessment for these rules in accordance with Texas Government Code, §2007.043. The following is a summary of that assessment. The specific purpose of the rulemaking action is to provide flexibility in the 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 to be able to demonstrate attainment with the ozone NAAQS. Promulgation and enforcement of these amended and new rules will not burden private, real property because this rulemaking action does not require an investment in the permanent installation of new refinery processing equipment. Although the amended and new rules do not directly prevent a nuisance or prevent an immediate threat to life or property, the LED program does prevent a real and substantial threat to public health and safety, and partially fulfill a federal mandate under 42 USC, §7410. Specifically, the emission limitations and control requirements within the LED program have been 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 §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 these rules is to provide flexibility in implementing cleaner-burning diesel fuel which is necessary for the HGA ozone nonattainment area to meet the 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 does not constitute a takings under the Texas Government Code, Chapter 2007.

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 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 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 Part 51 (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 comment on the consistency of the proposed rules with the CMP during the public comment period, but received no comment.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following dates and locations: June 13, 2001, Galveston; June 14, 2001, Rosenberg and Houston; June 15, 2001, Austin; and July 2, 2001, Houston. The public comment period closed on July 2, 2001.

The following commenters provided oral testimony and/or submitted written testimony: American Trucking Associations (ATA), Business Coalition for Clean Air (BCCA), Environmental Defense (ED), EPA, Galveston-Houston Association for Smog Prevention (GHASP), Houston Metropolitan Transit Authority (Metro), National Petrochemical and Refiners Association (NPRA), Sierra Club Houston Regional Group (Sierra-Houston), Texas Association of Businesses and Chambers of Commerce (TABCC), Texas Motor Transportation Association (TMTA), Texas Oil and Gas Association (TxOGA), and Texas Petroleum Marketers and Convenience Store Association (TPCA). EPA, Metro, NPRA, and TABCC generally supported the proposal, while ATA, BCCA, ED, GHASP, Sierra-Houston, TMTA, TxOGA, and TPCA generally opposed the proposal. EPA, Sierra-Houston, TMTA, and TxOGA suggested changes to the rule language.

RESPONSE TO COMMENTS

ATA, NPRA, TABCC, TMTA, and TxOGA expressed opposition to all region-specific, patchwork, or boutique fuel control strategy methods and requested that the commission refrain from implementing the proposed rules. TxOGA strongly urged the commission to refrain from adopting the proposed LED requirements and to align the commissions's SIP planning with the federal diesel program. ATA and TMTA expressed strong opposition to the LED rules and supported a single uniform national diesel fuel standard and the use of incentive-based programs to reduce $NO_x$ emission in the HGA area. TxOGA strongly recommended that the commission repeal all portions of these rules, including the rules regarding aromatics and cetane, and refrain from seeking a waiver to regulate diesel in Texas. TPCA opposed the commission's adoption of LED rules. BCCA supported the new national fuel standards as the best way to ensure cleaner-burning fuels at a reasonable costs to consumers and recommended that the regional diesel fuel requirement be removed from the SIP in favor of the national fuel.

The concerns raised by these comments were addressed in the previous rulemaking for the LED rules adopted by the commission on December 6, 2000 and published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 328), and do not specifically address changes to the rules associated with this rulemaking. Therefore, the commission made no changes in the rule language in response to these comments.

ED commented that delaying LED implementation until 2005 is backsliding from the December 2000 SIP. GHASP commented that the implementation delay from May 1, 2002 until April 1, 2005 is unnecessary and will result in less widespread use of catalytic devices to control emissions by 2007, resulting in fewer than 5.7 tpd in $NO_x$ reduction. Sierra-Houston commented that the proposal to delay the diesel fuel regulation from 2002 to 2005 is a mistake. Sierra-Houston opposed the diesel fuel specifications that allow 500 ppm sulfur in diesel fuel from May 1, 2002 to April 1, 2005 because 500 ppm of sulfur will poison, inactivate, and degrade catalysts. Sierra-Houston questioned why is the commission delaying LED fuel until 2005 instead of requiring it by 2002 because the commission admitted in the proposed SIP revision that diesel fuel sulfur level could have a significant impact on aftermarket $NO_x$ reduction systems which are often fouled by exposure to higher sulfur level.

The commission is prohibited from implementing the LED fuel standards until after February 2005 as a result of HB 2912, Article 15, 77th Legislature, 2001. In addition, EPA has expressed an opinion that the 2004 heavy-duty engine emission standards can be met without recourse to $NO_x$ after-treatment devices, therefore, sulfur reductions are not expected to generate further $NO_x$ reductions beyond the engine standards themselves. For these reasons, further sulfur controls to enable the use of catalytic converters are unnecessary until the implementation of the 2007 heavy-duty engine emission standards. The commission made no changes in the rule language in response to these comments.

NPRA and TxOGA commented that the proposed LED rules will have a negative impact on supplies of on-road and non-road diesel fuel for Texas. TABCC commented that the rules would put supply at risk for diesel fuel users by forcing state-specific requirements on the existing Texas diesel manufacturing and distribution system which is currently committed to producing federal diesel fuel. 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 doubt as to whether the distribution system can handle ultra-low sulfur product and maintain the integrity of the sulfur level if higher sulfur products are being shipped in the same system.

The concerns raised by these comments were addressed in the previous rulemaking for the LED rule adopted by the commission on December 6, 2000, and do not specifically address changes to the rules associated with this rulemaking. The commission made no changes in the rule language in response to these comments.

TPCA commented that many of their members would be at risk of losing their business if the commission adopts these changes to Chapter 114, because many of the over-the-road truckers would refuel outside the affected counties. TPCA further commented that every one of the truck stops in the affected counties would be put on an uneven playing field competing with truck stops outside the affected counties that will be purchasing non-LED fuel at $.15 to $.20 per gallon cheaper.

The commission acknowledges that over-the-road trucks have the fuel carrying capacity to travel hundreds of miles between refueling stops and that the price of fuel could play a large part in determining refueling location. Therefore, the possibility of increased out-of-area refueling by diesel truck traffic does exist and has been considered by the commission. The issue would exist whether the program was implemented statewide or in the smaller region as adopted in these amendments. However, as noted in the preamble, the reduction in coverage area will reduce the cost burden upon areas of the state that would not benefit as much from the use of LED as those counties that have previously been included in regional air pollution control strategies for the HGA nonattainment area. The commission has previously received information from diesel fuel refiners and suppliers in Texas that a state-wide requirement would exceed the capacity of refiners to provide the clean fuel when it is required, creating the possibility that adequate LED would not be available to achieve the anticipated emission reductions. Limiting LED to the central and eastern region of Texas, rather than requiring on-road LED for the whole state, ensures that there will be sufficient clean diesel for areas of the state where it is most needed. The commission made no change to the rule language in response to these comments.

ATA and TMTA commented that the proposed rules overstate the environmental benefits derived from the use of LED because they fail to account for economic incentive to purchase noncompliant fuel. ATA and TMTA further commented that the use of federal fuel has not been accounted for because the majority of diesel fueled vehicles are involved in "pass through" activities and would have an economic incentive to refuel outside the control area. This would be especially true when non-LED fuel will be available within a very short distance, i.e., the Texas-Louisiana border is only about 50 miles from the HGA area. Additionally, ATA and TMTA commented that the commission has not considered the cost of purchasing LED because the commission has failed to take into account the fact that some Texas refineries will choose not to produce LED fuel, resulting in tighter supplies and higher prices. ATA and TMTA further commented that trucking companies located inside the affected areas would be at a considerable competitive disadvantage because the higher fuel costs associated with LED could not be passed on to customers due to competition from trucking firms located outside the affected areas.

The concerns raised by these comments were addressed in the previous rulemaking for the LED rules adopted by the commission on December 6, 2000, and do not specifically address changes to the rules associated with this rulemaking. The commission believes that the amendments will ensure participation of more refineries, thus mitigating the problems raised by the commenters. The commission made no changes in the rule language in response to these comments.

TABCC and TxOGA commented that the environmental benefits of the LED are overstated, because the commission's analysis is based on outdated data and ignored more recent data. TxOGA stated that they have serious doubts that these rules will provide the desired benefits in terms of $NO_x$ emission reductions and ambient air quality in the three nonattainment areas. TxOGA stated that the Eastern Research Group analysis is based on a very narrow data set that fails to model the real world. TxOGA quoted EPA's estimates on diesel parameters and commented that if they were assumed correct, the proposed Texas LED will fail to achieve the desired $NO_x$ reductions in the HGA area. TxOGA pointed out that the EPA is studying this very issue.

The concerns raised by these comments were addressed in the previous rulemaking for the LED rules adopted by the commission on December 6, 2000, and do not specifically address changes to the rules associated with this rulemaking. The commission made no changes in the rule language in response to these comments.

ATA, TxOGA, TMTA, and TPCA commented that the investment costs are under estimated.

The concerns raised by these comments were addressed in the previous rulemaking for the LED rules adopted by the commission on December 6, 2000, and do not specifically address changes to the rules associated with this rulemaking. In fact, the amendments adopted in this rulemaking should help to address the concerns expressed by the commenters. The commission made no changes in the rule language in response to these comments.

BCCA commented that they applaud the commission's decision to remove the regional gasoline from the proposed SIP before it was adopted in December 2000. However, they stated a continuing concern about the regional diesel that was adopted at that time, and referred to a detailed discussion of their concerns in their Appendix A (September 2000) comments document.

The concerns raised by these comments were addressed in the previous rulemaking for the LED rules adopted by the commission on December 6, 2000, and do not specifically address changes to the rules associated with this rulemaking. The commission made no changes in the rule language in response to these comments.

NPRA commented that they have serious concerns about the commission's sulfur standards and that a recent report prepared by the Department of Energy, Energy Information Administration, *The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply*, May 2001, concluded that potential diesel fuel supply issues could occur as a result of ultra-low-sulfur diesel fuel requirements as those in the current LED rules. NPRA further commented that the commission should repeal the LED program's ultra-low sulfur standards for highway and non-road diesel fuel because they threaten the commission's need for assurance that there will be sufficient and affordable clean diesel in 2006.

The concerns raised by these comments were addressed in the previous rulemaking for the LED rules adopted by the commission on December 6, 2000, and do not specifically address changes to the rules associated with this rulemaking. In fact, the amendments adopted in this rulemaking should help to address the concerns expressed by the commenter. The commission made no changes in the rule language in response to these comments.

TxOGA commented that the implementation schedule is not practical, and that it is not realistic for Texas to require major fuel property changes in 2005, and then expect the industry to further respond to federal changes in 2006. TABCC commented that the production schedule is impractical given the commitment of Texas refiners to produce federal diesel in 2006.

The commission acknowledges that the implementation schedule may be difficult for some producers to comply with if major refinery modifications are required. However, the 2005 implementation date does not require any further reductions in sulfur than required by current federal regulations and the amended rules allow the producer to use an approved alternative diesel fuel formulation or alternative emission plan if it is equivalent in emission reduction benefits to diesel fuel meeting the rules' aromatic and cetane standards. Additionally these amendments have reduced the area of coverage for this fuel which should decrease the amount of changes that must occur prior to the federal deadline. The commission believes that the industry is already planning refinery changes to meet both the EPA Tier II low sulfur gasoline and the 2006 federal ultra-low sulfur diesel standards and should be able to complete these projects within the framework of the rules' implementation schedule.

Metro-Houston supported the later implementation date and the additional flexibility allowed in the rules, however, they expressed a concern about the potential price fluctuations and the impact the fluctuations would have on their operating budgets. NPRA and TABCC supported the delay the implementation date by three years (from May 1, 2002 to April 1, 2005), the reduction in the coverage area from statewide to 110 central and eastern Texas counties, and the allowing of compliance flexibility for alternative emission reduction plans for individual companies.

The commission appreciates the support for this rulemaking. The commission acknowledges that there could be an estimated $.08 per gallon increase in fuel production costs as a result of these rules and 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 April 2005 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 British Petroleum OATS process, could significantly reduce production costs and could help alleviate concerns about cost and supply availability.

TxOGA commented that federal low-sulfur diesel rules should supercede these rules because the emission benefits are nearly equivalent and the cost to the consumer clearly favors the federal rules.

The concerns raised by these comments were addressed in the previous rulemaking for the LED rules adopted by the commission on December 6, 2000, and do not specifically address changes to the rules associated with this rulemaking. The commission made no changes in the rule language in response to these comments.

TxOGA commented that the application of fuels control measures in attainment areas is not supported for reasons ranging from outright lack of air quality need to a host of legal issues including federal preemption, waiver requirements, and state-level prohibitions. TxOGA further commented that these rules do not need not be statewide.

As noted in the rule preamble, the geographical coverage area of these rules in regard to the on-road use of LED has been reduced from statewide coverage to 110 central and eastern Texas counties. The concerns raised by the comments regarding lack of air quality need and legal issues such as federal preemption, waiver requirements and state-level prohibitions were addressed in the previous rulemaking for the LED rules adopted by the commission on December 6, 2000, and do not specifically address changes to the rules associated with this rulemaking. However, the involvement of regional attainment counties as part of the $NO_x$ emission control strategy is necessary for the HGA area to demonstrate attainment of the ozone NAAQS. This regional coverage will also provide a greater market for diesel fuel producers and importers to provide the fuel required by these regulations and should help alleviate concerns regarding out-of- area refueling practices. The commission made no changes in the rule language in response to these comments.

TxOGA commented that they do not believe that this proposal is legally defensible, and stated concerns which included federal preemption on sulphur controls for diesel fuel, lack of federal authority to require controls in attainment areas, and the availability of alternate (and much less costly) alternatives.

The concerns raised by these comments were addressed in the previous rulemaking for the LED rules adopted by the commission on December 6, 2000, and do not specifically address changes to the rules associated with this rulemaking. As shown in the modeling for the SIP that is associated with this control strategy, the state is requiring no more emission reductions than absolutely required to meet the standard. The SIP submittal included a waiver request which demonstrates that no other alternative strategies are practicable. This waiver has been proposed for approval by the EPA (*Federal Register*, Volume 66, Number 134, Pages 36542 - 36547, July 12, 2001). The commission made no changes in the rule language in response to these comments.

ATA submitted, as part of their comments to these rules, a copy of a letter to EPA requesting the EPA to withdraw its proposed approval of the LED fuel waiver for the DFW SIP.

The commission acknowledges the receipt of this letter to EPA as part of the public record, but does not believe it is appropriate to respond in this rulemaking to comments addressed specifically to EPA regarding an EPA rulemaking.

ATA and TMTA commented that the commission will not be able to obtain a fuel waiver from the EPA because it has failed to demonstrate the need for LED under the FCAA. They also commented that the environmental benefits are overstated because LED is not necessary for attainment. Finally, they stated that the commission failed to explain why more cost-effective measures are unreasonable or impracticable, and failed to consider existing programs implemented in other areas with demonstrated emission reductions, such as California's Carl Moyer Memorial Air Quality Standards Attainment Program.

The commission disagrees with these comments. The commission believes that it has submitted to the EPA sufficient data to substantiate the need for a fuel waiver from the EPA. In addition, the commission has adopted rules to implement the Texas Emission Reduction Plan (TERP) as established by SB 5, 77th Legislature, which provides incentive funding very similar to California's Carl Moyer program. However, as required by SB 5, the emission reductions associated with the TERP will be used to replace the emission reductions attributed to the construction shift and accelerated Tier 2 - Tier 3 engine purchase rules previously adopted by the commission as part of the DWF and HGA control strategies. SB 5 requires the commission to repeal the construction shift and accelerated Tier 2 - Tier 3 engine purchase rules. As shown in the modeling for the SIP that is associated with this control strategy, the state is requiring no more emission reductions than absolutely required to meet the standard. The SIP submittal included a waiver request which demonstrates that no other alternative strategies are practicable. This waiver has been proposed for approval by the EPA (*Federal Register*, Volume 66, Number 134, Pages 36542 - 36547, July 12, 2001). The commission made no changes in the rule language in response to these comments.

ATA, TMTA, and TxOGA commented that the commission's assertion that this rulemaking does not meet the statutory criteria mandating that an RIA be performed is erroneous because the LED rules clearly exceed federal fuel standards.

The LED rules were originally adopted on April 19, 2000, and at that time the commission received comments regarding the requirement to perform an RIA. As stated at that time, the commission held the position that the rules do not exceed a standard set by federal or state law. The federal standard used for comparison is the ozone NAAQS which is a more stringent standard in this case than the federal diesel program. The state is required to demonstrate compliance with this standard under federal law, 42 USC, §7410, and under state law, TCAA, §382.012 and §382.039. As shown in the modeling for the SIP that is associated with this control strategy, the state is requiring no more emission reductions than absolutely required to meet the standard. The SIP submittal included a waiver request which demonstrates that no other alternative strategies are practicable. This waiver has been proposed for approval by EPA (*Federal Register*, Volume 66, Number 134, Pages 36542-36547, July 12, 2001). Therefore, the commission was not required to perform an RIA for these rules when they were originally adopted.

The requirement to perform an RIA on subsequent revisions to the rules would be judged solely on the revisions, not the underlying rules. In this case, the revisions actually add flexibility for the regulated fuel providers by allowing for alternative emission reduction plans; delaying the implementation date from May 1, 2002 to April 1, 2005 to allow producers sufficient time to complete refinery modifications to comply with the LED requirements; and reducing the coverage area of the rules from statewide to those counties that have previously been included in the regional air pollution control strategy for the HGA nonattainment area. Because these revisions provide flexibility instead of promulgating new requirements, it is the commission's position that the revisions are not "major environmental rules" because they do not negatively impact a sector of the economy.

EPA commented that it fully supported the proposed changes to §114.314 and §114.319.

The commission appreciates the support for this rulemaking.

EPA requested that the commission clarify how the proposed §114.318 differs from §114.312(g), which allows for alternative diesel fuel formulations that achieve equivalent or better emissions reductions as that achieved by compliance with LED standards.

Under §114.318, the commission will allow the diesel fuel distributed by a producer who has had a substitute fuel emission reduction plan approved by the executive director to be considered as being in compliance with the requirements of LED program, regardless of the sulfur, aromatic, and cetane properties of the diesel fuel being distributed. This alternative emission reduction plan may involve reductions from an entirely different fuel strategy such as low emission gasoline. The alternative diesel fuel formulation requirements under §114.312(g) require producers to demonstrate that their alternative *diesel fuel* formulations are equivalent to LED in reducing emissions. The difference between the two sections is that §114.318 allows the use of an approved *plan* for an alternative method of reducing emissions from fuels other than diesel in lieu of complying with the LED fuel specification requirements; while §114.312(g) requires the use of a *diesel fuel* with alternative component properties. The commission made no changes in the rule language in response to this comment.

Sierra-Houston opposed the open-ended use of the phase in §114.318 of "deemed to be equivalent" as it allows too much discretion for the commission and could provide industry an incentive to pressure the commission to allow a substitute fuel that is not really equivalent. Sierra-Houston further commented that the commission must define "equivalent."

The commission disagrees that it is necessary to define "equivalent." This term has a commonly understood meaning. The commission will make every effort to ensure emissions equivalency for alternative plans, if approved.

EPA expressed concern about the implementation of provisions in these rules that require that a producer must demonstrate equivalent emission reductions attributable to a producer's "market share" and questioned what would happen if the market share changes significantly after the determination of equivalency is made. EPA requested that the commission clarify what is intended by this "market share" approach, in terms of both the time period during which the market share is estimated and the type of fuel to which it applies. EPA commented that its approval is needed for these alternative compliance plans and that one factor EPA will consider before approval is what safeguards have been included in the enforceable alternative plan to address the issue of market share.

The commission will require producers to submit documentation verifying their market share and to provide the commission with contingency plans to ensure emission reduction equivalency in case of reductions in market share. The commission's approval of an alternative emission reduction plan will be based on whether the plan demonstrates, to executive director satisfaction, that the alternative emission reduction strategy will reduce $NO_x$ emissions equivalent to what would have been reduced through the use of LED during the same time period. The rules do not limit alternative emission reduction plans to only diesel fuel control strategies, but could also include control strategies for other fuels, such as gasoline, aviation fuel, or jet fuel.

EPA requested that the commission clarify the date of compliance for alternative emission reduction plans because substitute fuel strategies must be submitted by January 2003 and approved by May 2003. EPA further requested that the commission clarify for the public its authority to expect early reductions given the statutory prohibition on requiring LED prior to 2005.

The date of compliance for alternative emission reduction plans would be no later than the compliance date for the LED rules, April 1, 2005, however, the compliance date may be earlier if elected by the producer. The commission's authority to expect early reductions from fuel strategies under an alternative emission reduction plan is based in the voluntary nature of this plan. A producer may opt to participate in this plan by providing clean fuel at a date earlier than required by state or federal law. Once the producer chooses this option, the requirement becomes mandatory.

Sierra-Houston commented that records must be kept for five years, like the recordkeeping requirements for upset and maintenance records, and not two years as the current rule requires.

Action regarding recordkeeping is beyond the scope of this rulemaking. The commission made no changes in the rule language in response to this comment.

STATUTORY AUTHORITY

The amendments and new section 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 the Texas Health and Safety Code, TCAA, §382.017, concerning Rules, 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, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.019, concerning Methods Used to Control and Reduce Emissions from Land Vehicles, which authorizes the commission to adopt rules to control and reduce emissions from engines used to propel land vehicles; §382.037(g), concerning Vehicle Emissions Inspection and Maintenance Program, which authorizes the commission to regulate fuel content if it is demonstrated to be necessary for attainment of the NAAQS; and §382.039, concerning Attainment Program, 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. The amendments and new section are also adopted under TCAA, §382.039(g) - (i), as amended by HB 2912, Article 15, which states that the commission may not establish before January 1, 2004, vehicle fuel standards which specify fuel content for any area of the state that are more stringent than EPA standards, unless specifically authorized by the legislature; the commission may not require the distribution of Texas LED as described in the SIP prior to February 1, 2005; and the commission may consider, as an alternative method of compliance, fuels to achieve equivalent emissions.

*§114.314. Registration of Diesel Producers and Importers.*

Each producer and importer that sells, offers for sale, supplies, or offers for supply from its production facility or import facility low emission diesel fuel (LED) which may ultimately be used in counties listed in §114.319 of this title (relating to Affected Counties and Compliance Dates) shall register with the executive director by December 1, 2004 to begin production or importation of LED April 1, 2005. Those producers or importers not registered by December 1, 2004, may not begin production or importation of LED until after April 30, 2005, and registration must occur within 30 days after the first date that such person will produce or import LED. Registration shall be on forms prescribed by the executive director and shall include a statement of acceptance of the standards and enforcement provisions of this division; and shall include a statement of consent by the registrant that the executive director shall be permitted to collect samples and access documentation and records. The executive director shall maintain a listing of all registered suppliers.

*§114.318. Alternative Emission Reduction Plan.*

Diesel fuel which is sold, offered for sale, supplied, or offered for supply by a producer who submits by January 31, 2003 an alternative emission reduction plan, which contains a substitute fuel strategy and which is approved by the executive director and the EPA no later that May 31, 2003, will be considered in compliance with the requirements of this division. In order to be approved, the plan must demonstrate the market share the producer supplies, demonstrate the reductions associated with compliance with this division attributable to the market share, specify a substitute fuel strategy that will achieve equivalent reductions, and contain adequate enforcement provisions. Early reductions may be deemed to be equivalent by the executive director and the EPA. The executive director may allow plans to be submitted after January 31, 2003; however any plan must be approved prior to the use of that plan for compliance with the requirements of this division.

*§114.319. Affected Counties and Compliance Dates.*

(a) Beginning April 1, 2005, affected persons in the counties listed in subsection (b) of this section 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 April 1, 2005, 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 September 28, 2001.

TRD-200105878

Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 18, 2001
Proposal publication date: June 15, 2001
For further information, please call: (512) 239-0348

♦ ♦ ♦

## SUBCHAPTER J. OPERATIONAL CONTROLS FOR MOTOR VEHICLES

## DIVISION 1. MOTOR VEHICLE IDLING LIMITATIONS

### 30 TAC §114.507

The Texas Natural Resource Conservation Commission (commission) adopts an amendment to §114.507, Exemptions. The commission adopts this amendment to Chapter 114, Control of Air Pollution from Motor Vehicles; Subchapter J, Operational Controls for Motor Vehicles; Division 1, Motor Vehicle Idling Limitations; and corresponding revisions to the state implementation plan (SIP). Section 114.507 is adopted *without changes* to the proposed text as published in the June 15, 2001 issue of the *Texas Register* (26 TexReg 4395) 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 1990 Amendments to the Federal Clean Air Act (FCAA) as codified in 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 §7511a(d), requires states to submit ozone attainment demonstration SIPs for severe ozone nonattainment areas such as HGA. The HGA area, defined as 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 several 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 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, the EPA policy regarding SIP elements and timelines went through changes. Two national initiatives in particular resulted in changing deadlines and requirements. The first of these initiatives was a program conducted by 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 the OTAG program, and OTAG 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 standard, the EPA proposed an interim implementation plan (IIP) 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, the one-hour 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 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 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-1999 ROP plan by December 31, 2000; and to perform a mid-course review by May 1, 2004.

The emission reduction requirements included as part of the December 2000 SIP revision represented 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.

A SIP revision for HGA was adopted by the commission on December 6, 2000 and was submitted to the EPA by December 31, 2000. The December 2000 SIP contained rules, enforceable commitments, and photochemical modeling analyses in support of the HGA ozone attainment demonstration. In addition, this SIP contained Post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contained 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.

In order for the HGA area to have an approvable attainment demonstration, the EPA 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 HGA nonattainment area will need to ultimately reduce $NO_x$ more than 750 tons per day (tpd) to reach attainment of the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of this rule amendment to the motor vehicle idling limitation rules will have no effect on the reduction of emissions, because the amendment merely specifies which entity is responsible for compliance in the case of rented or leased vehicles.

The commission adopts these revisions to Chapter 114 and to the SIP to address the concern that the current rule language may hold the owner of a vehicle leasing operation responsible for the actions of the lessee. The changes to the exemption section will clarify that the operator of rented and leased vehicles, not the owner, will be held responsible for complying with these rules, if the operator is not employed by the owner.

The truck leasing industry specifically expressed concern that the current language was similar to idling restrictions adopted in other states which resulted in the owner of a leased vehicle receiving notices of violation in the mail due to the actions of a lessor/operator not employed by the owner. In most cases, the owner of a leased or rented vehicle does not control the direct operation of that vehicle. The adopted changes are designed to clarify who is responsible for complying with the provisions in §114.502 in situations that involve rented or leased vehicles operated by a person not employed by the owner of the vehicle. The amendments to the rule are not expected to have a significant impact on air quality.

The motor vehicle idling limitations as established through the adoption of §§114.500, 114.502, 114.507, and 114.509 on December 6, 2000, states that no person shall cause, suffer, allow, or permit the primary propulsion engine of a motor vehicle to idle for more than five consecutive minutes in the counties listed in §114.509 of this title (relating to Affected Counties and Compliance Dates) when the vehicle is not in motion during the period of April 1 through October 31 of each calendar year. The eight Texas counties affected by these rules are Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties.

SECTION DISCUSSION

The amendments to §114.507 contain a new paragraph (10) which will clarify who is responsible for complying with the provisions in §114.502 in situations that involve a rented or leased vehicle operated by a person not employed by the owner of the vehicle.

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. A "major environmental rule" is one, 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.

In addition, this amendment does 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.

This amendment to Chapter 114 is 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, because it merely clarifies who is held responsible for compliance with the rules in the case of rented or leased vehicles, the owner/lessor or the lessee.

This amendment does not exceed an express standard set by federal law, because it implements requirements of 42 USC. 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. This proposed amendment was 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, 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 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 42 USC. The EPA 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 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 42 USC.

In addition, 42 USC, §7502(a)(2), requires attainment as expeditiously as practicable, and, §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 §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 §7511a(f) exemption from $NO_x$ measures for HGA expired on December 31, 1997. The expiration of the exemption under §7511a(f), was based on the finding that $NO_x$ reductions in HGA are necessary for attainment of the ozone standard. Therefore, the amendment is a necessary component of and consistent with the ozone attainment demonstration SIP for HGA, required by 42 USC, §7410.

During the 75th Legislative Session (1997), 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, this rule amendment does not exceed state requirements, and is 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, 382.039, 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 an RIA as provided in Texas Government Code, §2001.0225.

The commission invited public comment on the draft RIA determination, but received no comment.

TAKINGS IMPACT ASSESSMENT

The commission evaluated this rulemaking action and performed an analysis of whether the amendment is subject to Texas Government Code, Chapter 2007. The following is a summary of that analysis. The specific purposes of the vehicle idling limitation 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 $NO_x$ reasonably available control technology required by 42 USC, §7511a(f) for certain source categories. The specific purpose of the adopted amendment to the vehicle idling limitation rules is to clarify who is responsible for complying with the provisions in §114.502 in situations that involve rented or leased vehicles operated by a person not employed by the owner of the vehicle. Texas Government Code, §2007.003(b)(4), provides that Chapter 2007 does not apply to the vehicle idling limitation rules, because it was an action reasonably taken to fulfill an obligation mandated by federal law. The emission limitations and control requirements within the vehicle idling limitations 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 the vehicle idling limitations rulemaking action was to meet the air quality standards established under federal law as NAAQS. The purpose of this amendment is to clarify a requirement of the vehicle idling limitations rules. Attainment of the ozone standard will eventually require substantial $NO_x$ reductions as well as VOC reductions. Any $NO_x$ reductions resulting from the vehicle idling limitations rulemaking are no greater than what scientific research indicates is necessary to achieve the desired ozone levels. However, the 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 rules and the amendment 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. The vehicle idling limitations rules were developed 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 vehicle idling limitations rules significantly advance the health and safety purpose by reducing ozone levels in the HGA nonattainment area. Consequently, the amended rule meets the exemption in §2007.003(b)(13).

The commission included elsewhere in this preamble its reasoned justification for this strategy and 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 Texas Government Code, §2007.003(b)(4) and (13). For these reasons, the vehicle idling limitations rules and the adopted amendment do not constitute a takings under Chapter 2007 and do not require additional analysis.

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 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 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 as a result of this action. 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 invited public comment on the consistency of the proposed rule amendment with the CMP during the public comment period, but received no comment.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following dates and locations: June 13, 2001, Galveston; June 14, 2001, Rosenberg and Houston; June 15, 2001, Austin; and July 2, 2001, Houston. The public comment period closed on July 2, 2001.

The following commenters provided oral testimony and/or submitted written testimony: American Trucking Associations (ATA); Galveston-Houston Association for Smog Prevention (GHASP); Houston Metropolitan Transit Authority (Metro); Sierra Club Houston Regional Group (Sierra-Houston); Texas Motor Transportation Association (TMTA); and one individual. Metro and GHASP generally supported the proposal, while ATA, Sierra-Houston, TMTA, and one individual generally opposed the proposal. ATA, GHASP, Sierra-Houston, TMTA, and one individual suggested changes to the existing idling rules, but did not suggest changes to the proposed rule language in the section that was open for comment.

RESPONSE TO COMMENTS

Sierra-Houston and one individual stated that due to the idling rules' high personnel requirements, high time commitments, difficulty of enforcement, and relatively low pollution reduction potential the rule will be poorly implemented and become a low priority among the enforcing agencies. These two commenters further stated that the idling rules should be repealed and greater emission reductions found elsewhere. ATA and TMTA commented that the idling rules would not produce significant environmental benefit. While generally supporting the idling rules, GHASP expressed concern in regard to the possible lack of legality of the state's enforcement authority, and would like to see more adequate direction and funding be in place for the enforcement of the idling rules.

The concerns raised by these comments were addressed in the previous rulemaking for the motor vehicle idling limitations rules adopted by the commission on December 6, 2000 and do not pertain specifically to this rulemaking action. Therefore, the commission made no changes to the rule revision language in response to these comments.

ATA and TMTA also commented that they felt that the responsibility for compliance with idling restrictions must be placed upon truck operators rather than the owners.

As noted in the preamble, the commission's reason for this rulemaking was to address this particular issue and the intent of the added language to §114.507 is to clarify that the owner is not responsible for compliance in certain situations. The commission agrees that in the case of rented or leased vehicles that are operated by a person not employed by the owner of the vehicle, that the owner should not be held responsible for compliance of the provisions in §114.502.

STATUTORY AUTHORITY

The amendment is 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, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA. The amendment is also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for protection of the state's air; §382.019, concerning Methods Used to Control and Reduce Emissions from Land Vehicles, which authorizes the commission to adopt rules to control and reduce emissions from engines used to propel land vehicles; and §382.039, concerning Attainment Program, 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 September 28, 2001.

TRD-200105877
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 18, 2001
Proposal publication date: June 15, 2001
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, 117.106 - 117.110, and 117.119, concerning Utility Electric Generation in Ozone Nonattainment Areas; §117.138, concerning System Cap; §§117.203, 117.206, 117.210, 117.213, 117.214, and 117.219, concerning Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas; §§117.471, 117.473, 117.475, 117.478, and 117.479, concerning Boilers, Process Heaters, and Stationary Engines at Minor Sources; and §§117.510, 117.520, 117.534, and 117.570, concerning Administrative Provisions; and corresponding revisions to the state implementation plan (SIP).

Sections 117.10, 117.106 - 117.108, 117.119, 117.203, 117.206, 117.210, 117.213, 117.214, 117.219, 117.473, 117.475, 117.478, 117.479, 117.510, 117.520, 117.534, and 117.570 are adopted *with changes* to the proposed text as published in the June 15, 2001, issue of the *Texas Register* (26 TexReg 4400). Sections 117.101, 117.103, 117.109, 117.110, 117.138, and 117.471 are adopted *without changes* and will not be republished.

The amendments to Chapter 117, concerning Control of Air Pollution from Nitrogen Compounds, and revisions to the SIP require stationary diesel and dual-fuel engines in the Houston/Galveston (HGA) ozone nonattainment area to meet new emission specifications and operating restrictions in order to reduce nitrogen oxides ($NO_x$) emissions and ozone air pollution. The amendments also require new stationary gas turbines and duct burners at minor sources of $NO_x$ in HGA to meet emission specifications in order to reduce $NO_x$ emissions and ozone air pollution. In addition, the amendments improve implementation of the existing Chapter 117 by correcting typographical errors, updating cross-references, clarifying ambiguous language, adding flexibility, amending requirements to achieve the intended emission reductions of the program, and deleting the exemption for small (ten megawatts (MW) or less) electric generating units which are registered under a standard permit. Finally, the amendments revise the emission specifications for attainment demonstrations (ESADs) for electric utilities and landfill gas-fired stationary engines, revise the emission reduction schedule for sources other than electric utilities, and provide for alternate ESADs in the event that the TNRCC's continuing scientific assessment of the causes of and possible solutions to HGA's ozone nonattainment status results in a determination that attainment can be reached with fewer $NO_x$ emission reductions from point sources concurrent with additional emission reduction strategies.

The commission adopts these amendments to Chapter 117 and revisions 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 as codified in 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.

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 as codified in 42 USC, §§7401 et seq., and therefore is required to attain the one-hour ozone standard of 0.12 part 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 as 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 several 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 initiatives in particular resulted in changing deadlines and requirements. The first of these initiatives was a program conducted by 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 the OTAG program, and OTAG 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 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) 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, the one-hour 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-1999 ROP plan by December 31, 2000; and to perform a mid-course review by May 1, 2004.

The emission reduction requirements included as part of the December 2000 SIP revision represented 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.

A SIP revision for HGA was adopted by the commission on December 6, 2000 and submitted to the EPA by December 31, 2000. The December 2000 SIP contained rules, enforceable commitments, and photochemical modeling analyses in support of the HGA ozone attainment demonstration. In addition, this SIP contained Post-1999 ROP plans for the milestone years 2002 and 2005, and for the attainment year 2007. The SIP also contained 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.

In order for the HGA area to have an approvable attainment demonstration, the EPA 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 HGA ozone nonattainment area will need to ultimately reduce $NO_x$ more than 750 tons per day (tpd) to reach attainment of the one-hour standard. In addition, a VOC reduction of about 25% will have to be achieved. Adoption of rules which require stationary diesel and dual-fuel engines in HGA to meet new emission specifications and operating restrictions 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 tpd of $NO_x$ 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. As noted in the January 12, 2001 issue of the *Texas Register* (26 TexReg 526), as part of the December 2000 SIP revision for HGA 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 that issue of the *Texas Register* (26 TexReg 705), 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. Another table in the TABLES AND GRAPHICS section of that issue of the *Texas Register* (26 TexReg 706), 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 Chapter 117 rules adopted in December, 2000.

Based on this analysis, major sources in HGA were found to include 196 stationary emergency diesel engines, representing 5.4 tpd of $NO_x$ emissions. There are an estimated 2,500 additional stationary diesel engines, mostly emergency backup generators, as well as stationary diesel engines at locations such as rock crushers, sand and gravel plants, hot mix asphaltic concrete plants, and oil and gas drilling rigs. The exact number is unknown because many of these sources have not been inventoried as point sources for the emissions inventory. It should be noted that an engine must remain at a location (a single site at a building, structure, facility, or installation) for more than 12 consecutive months to meet the definition of "stationary internal combustion engine" in §117.10. In the softer rock in HGA, as compared to West Texas, for example, oil and gas drilling rigs are unlikely to be on-site for more than 12 consecutive months, according to the Texas Railroad Commission.

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, effective June 17, 1994. Under 40 CFR 89, diesel engines greater than 50 horsepower (hp) must comply with Tier 1 emissions standards that were 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 diesel 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.

Effective October 23, 1998, the EPA revised 40 CFR 89 and adopted more stringent emission standards for $NO_x$, non-methane hydrocarbons (NMHC), and particulate matter (PM) for new non-road diesel 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 diesel 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 117 - Preamble

While the EPA has addressed highway (on-road) and non-road engines, stationary diesel engines have yet to be addressed at the federal level. The adopted Chapter 117 rules will subject new and existing stationary diesel engines in HGA which operate at least 100 hours per year to emission specifications of either 11 grams per horsepower hour (g/hp-hr) (the estimated uncontrolled level) for existing engines or the Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of installation of new engines or modification, reconstruction, or relocation of existing engines. This will ensure that as turnover of older, higher-emitting stationary diesel engines occurs, the replacements will be cleaner engines. Dual-fuel engines at minor sources in HGA will be subject to an emission specification of 5.83 g/hp-hr (the estimated uncontrolled level) to address engines which are both gas- and diesel-fired. In addition, new and existing stationary diesel engines in HGA which operate at least 100 hours per year will be subject to the mass emissions cap and trade program of 30 TAC Chapter 101, Subchapter H, Division 3, concerning Mass Emissions Cap and Trade Program, if they are located at a site where the collective design capacity to emit $NO_x$ is at least ten tons per year (tpy).

New stationary diesel engines which operate less than 100 hours per year will be required to meet the Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of installation, while existing stationary diesel engines which operate less than 100 hours per year but are modified, reconstructed, or relocated will be required to meet the Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of modification, reconstruction, or relocation. Existing stationary diesel engines, if used exclusively in emergency situations, will continue to be exempt from the new emission specifications, but new, modified, reconstructed, or relocated stationary diesel engines placed into service on or after October 1, 2001 will be required to meet the Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of installation, modification, reconstruction, or relocation. This will ensure that as turnover of older, higher-emitting stationary diesel engines occurs, the replacements will be cleaner engines.

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 stationary diesel and dual-fuel engines for testing and maintenance, and delaying the release of $NO_x$ emissions until after noon in HGA, 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 stationary diesel and dual-fuel engines 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. Consequently, the adopted amendments will prohibit stationary diesel and dual-fuel engines in HGA from being started or operated for testing or maintenance between the hours of 6:00 a.m. and noon, beginning April 1, 2002.

SECTION BY SECTION DISCUSSION

The primary purpose of the amendments to Chapter 117 and revisions to the SIP is to establish new emission specifications and operating restrictions for stationary diesel and dual-fuel engines for the HGA ozone attainment demonstration. The current $NO_x$ reasonably available control technology (RACT) limits in §117.105 and §117.205, concerning Emission Specifications for Reasonably Available Control Technology (RACT), apply to certain boilers, process heaters, and stationary engines and stationary gas turbines. The revisions establish emission reduction requirements for stationary diesel engines which are currently exempt from the $NO_x$ RACT limits in §117.105 and §117.205, as well as from the emission specifications for attainment demonstrations in §117.106 and §117.206. The amendments also require new stationary gas turbines and duct burners at minor sources of $NO_x$ in HGA to meet emission specifications in order to reduce $NO_x$ emissions and ozone air pollution. In addition, the amendments improve implementation of the existing Chapter 117 by correcting typographical errors, updating cross-references, clarifying ambiguous language, adding flexibility, amending requirements to achieve the intended emission reductions of the program, and deleting the exemption for small (ten MW or less) electric generating units which are registered under a standard permit. Finally, the amendments revise the ESADs for electric utilities and landfill gas-fired stationary engines, revise the emission reduction schedule for sources other than electric utilities, and provide for alternate ESADs in the event that the TNRCC's continuing scientific assessment of the causes of and possible solutions to HGA's ozone nonattainment status results in a determination that attainment can be reached with fewer $NO_x$ emission reductions from point sources concurrent with additional emission reduction strategies.

The changes to §117.10, concerning Definitions, add definitions of "diesel engine," "emergency situation," and "pyrolysis reactor" and renumber subsequent definitions to accommodate the new definitions. The amendments to §117.10 also revise the definition of "electric generating facility (EGF)" in order to clarify that this definition includes an out-of-state owner that does business in Texas, and revise the lead-in paragraph to §117.10 by adding a sentence which notes that additional definitions for terms used in Chapter 117 are found in 30 TAC §101.1 and §3.2, concerning Definitions. This reference is intended as a courtesy to the reader who may not be familiar with the sections in which some definitions are located. Further, the changes to §117.10(2) revise the definition of "applicable ozone nonattainment area" by replacing the wording "pursuant to" with "under" for consistency with the commission's style guidelines.

In addition, the changes to §117.10 revise the definition of "electric power generating system" to clarify that in HGA, industrial cogeneration units and units owned by independent power producers are subject to §117.210, concerning System Cap, and to bring stationary diesel engines into this system cap for consistency with the changes to §117.210, described later in this preamble. As a result of the changes to the definition of "electric power generating system," the commission made revisions to the emissions banking and trading program of Chapter 101, Subchapter H, Division 3, adopted concurrently in this issue of the *Texas Register*. Specifically, the amendments to the figure in 30 TAC §101.353(a), concerning Allocation of Allowances, revise variable (3)(A) of the reduction factor equation by changing a reference from "§117.10" to a more complete reference to "§117.10(13)(A)(iii)" in order to ensure that non-electric utility EGFs (for example, industrial cogeneration units and units owned by independent power producers) remain on the same compliance schedule as other non-electric utility sources. The changes to the definition of "electric power generating system" further add a reference to duct burners used in turbine exhaust ducts for consistency with the new §117.101(4) and the revised §117.106(c)(3), which make the gas turbine ESAD applicable to duct burners used in turbine exhaust ducts.

The changes to §117.10 also add the word "and" to the definitions of "large DFW system" and "small DFW system" in order to improve the readability of these definitions. In addition, the changes to §117.10 add a reference to minor sources to the definition of "stationary gas turbine" in §117.10(44) for consistency with the change to the definition of "unit" described in the following paragraph.

Finally, the changes to §117.10 also revise the definition of "unit" to broaden its applicability. Currently, this definition includes stationary sources of $NO_x$ at major sources. Because Subchapter D, Division 2, concerning Boilers, Process Heaters, and Stationary Engines at Minor Sources, applies to stationary sources of $NO_x$ at minor sources, the amendments broaden the applicability of the definition of unit to include boilers, process heaters, stationary gas turbines, and stationary engines at minor sources. The current Subchapter D, Division 2, applies to boilers, process heaters, and stationary engines. As noted elsewhere in this preamble, the changes will establish new requirements in Subchapter D, Division 2, for stationary gas turbines (including any duct burner in a turbine exhaust duct), so it is necessary to include stationary gas turbines and duct burners in the definition of unit as it applies to minor sources.

The changes to §117.101, concerning Applicability, revise §117.101(a) to update a reference to the renumbered §117.10(13); and add a new §117.101(4) to clearly specify that duct burners in gas turbine exhaust ducts are included in the applicability of Subchapter B, Division 1 (Utility Electric Generation in Ozone Nonattainment Areas). This will ensure that emissions from a duct burner are subject to the same ESAD in HGA as the associated gas turbine of which the duct burner is an integral part. The new §117.101(4) will only affect units in HGA because §117.106, concerning Emission Specifications for Attainment Demonstrations, does not apply to gas turbines in the Beaumont/Port Arthur (BPA) or Dallas/Fort Worth (DFW) ozone nonattainment areas. Further, although §117.105, concerning Emission Specifications for Reasonably Available Control Technology (RACT), applies to gas turbines in BPA or DFW, §117.103(a)(1) exempts "any new units placed into service after November 15, 1992." The installation of duct burners is a relatively recent phenomenon, and the commission is unaware of any duct burners that were placed into service before November 15, 1992.

The change to §117.103, concerning Exemptions, deletes the exemption for small (ten MW or less) electric generating units which are registered under a standard permit. At the time of adoption of this exemption on December 6, 2000, the standard permit for small electric generating units (November 2000) contained output-based emission limits at least as clean as new central power plants, thereby having a minimal impact on the HGA Attainment Demonstration SIP. Subsequently, the commission has received information that applying output-based emission limits at this level to small electric generating units may not be feasible because of differences in operating efficiency between small (ten MW and less) and larger electric generating units. Therefore, the commission believes it is necessary to delete the exemption to ensure that there is no impact of $NO_x$ emissions on HGA.

The changes to §117.106, concerning Emission Specifications for Attainment Demonstrations, revise §117.106(c)(1)(A) to change the ESAD in HGA for gas-fired utility boilers from 0.010 pound per million British thermal units (lb/MMBtu) to 0.020 lb/MMBtu; and revise §117.106(c)(1)(B) to change the ESAD in HGA for coal-fired or oil-fired utility boilers from 0.030 lb/MMBtu to 0.040 lb/MMBtu. The changes have the effect of reducing the emission reduction requirement for the major HGA electric utility from 93% to 90%, based on its peak 30-day $NO_x$ emissions in 1998. The changes similarly reduce the percentage reduction required of the other Public Utility Commission (PUC)-regulated electric utility in HGA.

The point source $NO_x$ control strategy as adopted on December 6, 2000 had an associated $NO_x$ emission reduction of 595 tpd. While the revisions to the point source $NO_x$ rules are now expected to reduce $NO_x$ by 586 tpd, the effect of this increase is counterbalanced by reductions enacted by the Texas Legislature requiring the permitting of grandfathered facilities in east and central Texas. The legislature requires certain grandfathered sources in this region to reduce emissions of $NO_x$ by approximately 50%. The commission believes that the current rulemaking will provide similar air quality benefits to the December 6, 2000 SIP revision for several reasons. First, $NO_x$ emissions in east and central Texas will be significantly lower overall under the current SIP than under the December 6, 2000 SIP revision. Second, ozone production efficiency at the sources affected by the recent legislation is expected to be very high, based on recently published results from an ozone study conducted in the Nashville, Tennessee area by the Southern Oxidant Study. Results from the Texas 2000 Air Quality Study indicate that ozone production at the Reliant Energy, Incorporated (Reliant) W. A. Parish power plant is three to five times lower than what is expected from the rural grandfathered sources. No data is currently available on ozone production efficiency at other Reliant units, but it is expected to be somewhat higher than that at the Parish facility. Third, the increased $NO_x$ emissions will occur at peaking units, which generate most of their emissions in the afternoon, at least during the ozone season. Modeling has shown that afternoon emissions are less important in ozone formation than are morning emissions.

In any case, the revised ESAD is cost-effective in terms of cost per ton of $NO_x$ compared to the ESADs in the December 6, 2000 SIP revision, and results in a very large reduction in emissions. Detailed modeling will be required to quantitatively assess the overall effect of these two compensating changes to the emissions inventory. The commission will address this issue during the first phase of the mid-course review.

In addition, the changes to §117.106 revise §117.106(c) to clarify that "the lower of any applicable permit limit" refers to limits in any permit issued before January 2, 2001, any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, or any limit in a permit by rule under which construction commenced by January 2, 2001.

The changes to §117.106 also revise §117.106(c)(3) to clearly specify that duct burners in gas turbine exhaust ducts are subject to the same ESAD as stationary gas turbines. This is consistent with the new §117.101(4) for duct burners described earlier in this preamble.

Further, the changes to §117.106 add a new §117.106(c)(5) which specifies that if, and to the extent supported by, the commission's continuing scientific assessment of the causes of and possible solutions to HGA's ozone nonattainment status results in a determination that attainment can be reached with fewer $NO_x$ emission reductions from point sources concurrent with additional emission reduction strategies, then the executive director will develop a SIP revision involving revisions to the utility and non-utility ESADs for consideration at a commission agenda no later than June 1, 2002. In the event that the total $NO_x$ emission reductions from utility and non-utility point sources required for attainment is determined to be 80% from the 1997 emissions inventory baseline, the revised specifications shall be the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the specifications in the subparagraphs of the section. The commission reserves all rights to assign any additional $NO_x$ reduction benefits supported by the science evaluation to the relief of other control measures, including further $NO_x$ point source relief.

As has been EPA's legal position since 1975 and TNRCC's policy, the SIP can be revised to adjust requirements, based upon new information, technology, or science, provided the ultimate goal of the SIP is achieved and all requirements of the federal act are met. The mid-course review is a well defined approach that incorporates this policy. In order to ensure that the HGA area is in attainment by 2007 and that the controls to get there are the most cost-effective technology-based solutions possible, the commission has committed to performing a mid-course review (see the commission's enforceable commitment adopted in April 2000). The mid-course review process has already begun and will continue, ultimately resulting in a SIP revision submitted to EPA by May 1, 2004. There are planned opportunities throughout the process, as described in the SIP, to incorporate the latest information and make decisions. This effort will involve a thorough evaluation of all modeling, inventory data, and other tools and assumptions used to develop the attainment demonstration. It will also include the ongoing assessment of new technologies and innovative ideas to incorporate into the plan. For example, the commission is committed to developing an effective plan to minimize releases of reactive hydrocarbon emissions and the emissions of chlorine. To the extent that the science confirms the benefit from this program, then it is the intent of the commission to implement such a program through a SIP revision which will first offset $NO_x$ reductions from utility and non-utility sources down to the 80% (535 tpd) level. The commission, in its discretion, may allocate any additional benefit beyond 80% to other SIP strategies and/or to the point source $NO_x$ control strategy. Based upon current analysis, this 80% from utility and non-utility sources would result in a total reduction of not less than 535 tpd $NO_x$ emissions from utility and non- utility sources in the HGA area.

The alternate ESADs in §117.106(c)(5)(A)(C) were provided by the Business Coalition for Clean Air (BCCA) Appeal Group as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described later in this preamble in the first paragraph of the ANALYSIS OF TESTIMONY section.

The $NO_x$ control levels in the alternate ESADs for different $NO_x$ point sources vary by source, but are intended to achieve an overall $NO_x$ point source reduction of 535 tpd, which is an approximate 80% reduction from the 1997 emission point source inventory of 668 tpd. The alternate ESADs also include a new category, pyrolysis reactors, that was previously included within the category of process heaters. This agreed reduction, which is contingent upon the outcome of the science evaluation discussed elsewhere in this preamble, was proposed for public comment as a part of that agreement. The commission solicited public comment on the BCCA Appeal Group's proposed alternate ESADs from all interested persons, including all owners and operators of $NO_x$ point sources and other stakeholders who are not members of the BCCA Appeal Group. The commission reserves all rights to assign any additional $NO_x$ reduction benefits supported by the science evaluation to the relief of other control measures, including further $NO_x$ point source relief. Comments received regarding this issue are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

As noted earlier in this preamble, the TABLES AND GRAPHICS section of the January 12, 2001 issue of the *Texas Register* (26 TexReg 705) included a table titled "Potential $NO_x$ Emission Reductions by Point Source Category for Houston/Galveston Nonattainment Area Counties" which indicates the relative proportion of emissions according to equipment category. Another table in the TABLES AND GRAPHICS section of that issue of the *Texas Register* (26 TexReg 706), 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 Chapter 117 rules adopted in December, 2000.

In the TABLES AND GRAPHICS section of this issue of the *Texas Register*, the table titled "Potential $NO_x$ Emission Reductions from Alternate ESADs by Point Source Category for Houston/Galveston Nonattainment Area Counties" indicates the relative proportion of emissions according to equipment category and estimated reductions in the event that the alternate ESADs are implemented, as well as the effect of the revisions to the utility boiler ESADs in §117.106(c)(1) and the new diesel engine ESADs in §117.206(c)(9)(D). The commission uses the term "Tier I" to refer to combustion modifications, "Tier II" to refer to flue gas cleanup (i.e., post-combustion control), and "Tier III" to refer to the combination of Tier I and Tier II controls.

Figure 2: 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 from Alternate ESADs for Houston/Galveston Nonattainment Area Counties," further breaks down the equipment categories and indicates the estimated $NO_x$ emission reductions which would result in the event that the alternate ESADs are implemented.

Figure 3: 30 TAC Chapter 117 - Preamble

In addition, the changes to §117.106 delete the word "boiler," which is a typographical error, in §117.106(d), and correct the references in §117.106(a) and (e)(1)(B) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)).

Finally, the changes to §117.106 revise §117.106(e)(4) by deleting the superfluous word "alternative" and allowing owners or operators of EGFs in the HGA ozone nonattainment area who are required to participate in a system cap under §117.108 to trade emissions with other participating owners or operators of EGFs in the same ozone nonattainment area under the requirements of Chapter 101, Subchapter H, Division 1, 4, or 5, concerning Emission Credit Banking and Trading; Discrete Emission Credit and Trading Program; and System Cap Trading. The change will give the owners and operators of EGFs in HGA additional flexibility in meeting their system caps either through the use of emission reduction credits (ERCs), discrete emission reduction credits (DERCs), or through the transfer of emission allowables among EGFs participating in a system cap that are in the same nonattainment area. This flexibility is already available in DFW.

The changes to §117.107, concerning Alternative System-wide Emission Specifications, revise §117.107(a) to update a reference to the renumbered §117.10(13), spell out the abbreviation for the term "MMBtu" in §117.107(a)(3), and abbreviate the term "lb/MMBtu" in §117.107(b)(1) - (3).

The changes to §117.108 and §117.138, concerning System Cap, revise §117.108(b) and §117.138(b) by updating references to the renumbered §117.10(13). The changes to §117.108 also make revisions within the figure in §117.108(c)(1) to specify January 2, 2001 as the cutoff for administratively complete permit applications under 30 TAC Chapter 116 and start of construction of EGFs under a 30 TAC Chapter 106 permit by rule. This date is consistent with §101.353. The changes within the figure in §117.108(c)(1) also revise the system cap for EGFs in the definition, $H_i$, (B)(i), by allowing the owner or operator to choose any consecutive 30-day period within the third quarter, rather than the system highest 30-day period. This option is also reflected in the definition of $H_i$, (B)(ii). This change will provide flexibility to systems which include both coal- and gas-fired units.

In addition, the changes to §117.108 revise §117.108(c)(1) by modifying the method of determining level of activity for new EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in 30 TAC §101.350, concerning Definitions. The 180-day adjustment period addresses that period of time from first start-up to establishment of normal operating conditions for a new facility.

In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period. A principal goal is to provide incentive to make emissions reductions. The commission believes that owners or operators who install and operate cleaner equipment should have the opportunity to fully integrate that equipment at a realistic level of operation that is representative of the demands that will be placed on the equipment. The commission believes that a five-year period to establish a baseline will allow this integration, while timely establishing the necessary emissions cap. This is consistent with the corresponding revisions to §101.353 which add the option of a five-year period to establish a baseline and the availability of an additional two-year period in extenuating circumstances.

The change to §117.109, concerning System Cap Flexibility, allows owners or operators of EGFs in the BPA and HGA ozone nonattainment areas who are participating in a system cap under §117.108 to trade emissions with other participating owners or operators of EGFs in the same ozone nonattainment area under the requirements of Chapter 101, Subchapter H, Division 1, 4, or 5. The change will give the owners and operators of EGFs in BPA and HGA additional flexibility in meeting their system caps either through the use of ERCs, DERCs, or through the transfer of emission allowables among EGFs participating in a system cap that are in the same nonattainment area. This flexibility is already available in DFW.

The change to §117.110, concerning Change of Ownership - System Cap, clarifies the impact of a change of ownership on a system cap. The current rule language states that in the event that a unit of an electric power generating system is sold or transferred, the unit shall become subject to the transferee's emission cap. The change will clarify that the sentence regarding the value $R_i$ in §117.108(c) based on the unit's status as part of a large or small system as of January 1, 2000 is specific to electric power generating systems in DFW (either a large DFW system, or small DFW system, as defined in §117.10).

The changes to §117.119, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.119(b) and (c) to more accurately direct testing results and notifications of initial demonstration of compliance testing to the proper agency and local program representatives. Specifically, the revisions to §117.119(b) specify that verbal notification of initial demonstration of compliance testing and continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) performance evaluation should be made to the appropriate regional office and any local air pollution control agency having jurisdiction, rather than the executive director. In addition, the revisions to §117.119(c) specify that a copy of the initial demonstration of compliance testing should be provided to the Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction, rather than the executive director. Any testing results sent to the Office of Compliance and Enforcement should include the notation "Engineering Services Team (MC 171)" to help ensure accurate mail delivery. The changes to §117.119 also revise §117.119(e)(5) by replacing the wording "pursuant to" with "in accordance with" for consistency with the commission's style guidelines.

The changes to §117.203, concerning Exemptions, add a reference to the new §117.206(i) described later in this preamble to make all stationary diesel and dual-fuel engines in HGA subject to the maintenance and testing operating schedule restrictions; add a reference to the final control plan requirements of §117.216(a)(5) for units claimed to be exempt from the emission specifications; and add references to the run time meter and recordkeeping requirements of §§117.213(i), 115.214(a)(2), and 117.219(f)(6) for units exempted from the emission specifications due to low annual hours of operation.

In addition, the changes to §117.203 replace the existing exemption in §117.203(a)(6)(A) for stationary gas turbines and engines operated exclusively for firefighting and/or flood control with an exemption for stationary gas turbines and engines used exclusively in emergency situations, as defined in the new §117.10(14). However, operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average. Fifty-two hours per year allows up to one hour per week of maintenance or testing, which is a reasonable upper bound for this type of operation. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service in HGA on or after October 1, 2001 is ineligible for this exemption. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in 30 TAC §116.10, concerning General Definitions, and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in 30 TAC §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account.

New and existing engines will continue to be eligible for exemption under §117.203(a)(6) if they are used for one or more of the following purposes: research and testing; performance verification and testing; solely to power other engines or gas turbines during start-ups; in response to and during the existence of any officially declared disaster or state of emergency; or directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals. The net effect is that existing stationary diesel and dual-fuel engines, if used exclusively in emergency situations, will continue to be exempt from the new emission specifications, but new, modified, reconstructed, or relocated stationary diesel engines placed into service on or after October 1, 2001 will be required to be cleaner diesel engines. Specifically, these new, modified, reconstructed, or relocated stationary diesel engines will be required to meet the federal Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines in effect at the time of installation, modification, reconstruction, or relocation.

The changes to §117.203 also delete a redundant exemption in §117.203(a)(6)(B) for operation of stationary gas engines and turbines which operate less than 850 hours per year. An exemption for these sources in the BPA and DFW ozone nonattainment areas is available under §117.205(h)(9) and the revised §117.206(g)(2) (described later in this preamble). An exemption from RACT is likewise available for these sources in HGA under §117.205(h)(9), but there is no exemption from the ESADs in HGA for stationary gas engines and turbines which operate less than 850 hours per year. Consequently, deletion of §117.203(a)(6)(B) will not result in additional requirements in BPA, DFW, or HGA.

In addition, the changes to §117.203 revise §117.203(a)(10) for consistency with the definition of "diesel engine" and make it specific to engines in BPA and DFW due to the new emission requirements for diesel engines in HGA.

The changes to §117.203 further add a new §117.203(a)(11) to exempt existing stationary diesel engines in HGA (specifically, those placed into service before October 1, 2001) which operate less than 100 hours per calendar year, based on a rolling 12-month average. The new §117.203(a)(11) excludes any modified, reconstructed, or relocated engine placed into service on or after October 1, 2001. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in §116.10 and 40 CFR §60.15, respectively, and the term "relocated" means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account.

The changes to §117.203 also add a new §117.203(a)(12) for new, modified, reconstructed, or relocated stationary diesel engines placed into service in HGA after October 1, 2001 which operate less than 100 hours per calendar year, based on a rolling 12-month average, in non- emergency situations. This allows operation of stationary diesel engines during an emergency situation for as many hours as the emergency situation, as defined in §117.10(14), continues to exist. To qualify for this exemption, the engine must meet the EPA's Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines listed in 40 CFR §89.112(a), Table 1 and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in §116.10 and 40 CFR §60.15, respectively, and the term "relocated" means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account.

In addition, the changes to §117.203 also revise §117.203(b) to eliminate the reference to the exemption in §117.203(a)(6)(B) which, as described earlier in this preamble, was deleted because it is redundant.

Finally, the changes to §117.203 delete the exemption in §117.203(c) for small (ten MW or less) electric generating units which are registered under a standard permit. At the time of adoption of this exemption on December 6, 2000, the proposed standard permit for small electric generating units (November 2000) contained output-based emission limits at least as clean as new central power plants, thereby having a minimal impact on the HGA Attainment Demonstration SIP. Subsequently, the commission has received information that applying output-based emission limits at this level to small electric generating units may not be feasible because of differences in operating efficiency between small (ten MW and less) and larger electric generating units. Therefore, the commission believes it is necessary to delete the exemption to ensure that there is no greater impact of $NO_x$ emissions on HGA.

According to a comment received during previous rulemaking, emergency generators usually do not operate more than 100 hours per year. (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 585)). However, engines which are used to shave peak electric demand tend to operate on hot days that coincide with higher probability of ozone exceedances. Therefore, it is necessary to establish emission specifications for these engines and include them in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3.

The changes to §117.206, concerning Emission Specifications for Attainment Demonstrations, revise §117.206(c) to clarify that "the lower of any applicable permit limit" refers to limits in any permit issued before January 2, 2001, any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, or any limit in a permit by rule under which construction commenced by January 2, 2001, and revise §117.206(c)(2)(B), (3)(B)(ii), and (16)(A) to clarify that a consistent methodology must be used for the ESADs for fluid catalytic cracking units (FCCUs) (including carbon monoxide (CO) boilers, CO furnaces, and catalyst regenerator vents), boilers and industrial furnaces (BIF units), and incinerators which are based on a specific percent reduction from the emission factor used to calculate the June - August 1997 daily $NO_x$ emissions. This is necessary to prevent an owner or operator from using an emission factor which overestimates the June - August 1997 daily $NO_x$ emissions, using an emission factor which more accurately estimates the $NO_x$ emissions, and then claiming credit for the resultant "paper" emission reductions without actually achieving the real emission reductions that the rule is intended to achieve. The changes to §117.206(c)(2)(B), (3)(B)(ii), and (16)(A) are necessary because of, and are consistent with, the new 30 TAC §101.354(b), concerning Allowance Deductions, that the commission added to the emissions banking and trading program of Chapter 101, Subchapter H, Division 3, concurrently in this issue of the *Texas Register*.

The changes to §117.206 also revise §117.206(c)(9)(A) and (B) to establish an ESAD of 0.60 g $NO_x$/hp-hr for stationary engines which are fired on landfill gas. The existing ESADs of 0.17g $NO_x$/hp-hr and 0.50 g $NO_x$/hp-hr for gas- fired rich-burn and lean-burn engines, respectively, are based on use of flue gas cleanup and remain the ESADs for those engines not fired on landfill gas. However, it has come to the commission's attention that landfill gas contains siloxanes which rapidly poison the catalyst of flue gas cleanup controls. The revised ESAD for stationary engines which are fired on landfill gas is based upon combustion modifications and is necessary to ensure that the ESAD for these engines is technically feasible.

Additionally, the changes to §117.206 add a new §117.206(c)(9)(D) which establishes emission specifications for stationary diesel engines which are based on the EPA's Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines listed in 40 CFR §89.112(a), Table 1. Because the Tier 2/Tier 3 standards and some of the Tier 1 standards are expressed in terms of NMHC + $NO_x$, the commission used Table 2 entitled Combined and Pollutant-Specific Emissions Standards for Nonroad Diesel Engines from *Exhaust Emission Factors for Nonroad Engine Modeling -- Compression Ignition, Report No. NR-009A*, (revised June 15, 1998) to split the combined NMHC+$NO_x$ standards into single pollutant emission factors. While Table 2 notes that pollutant-specific components have no regulatory significance within the Tier 2/Tier 3 program and were derived to facilitate modeling analyses, it is necessary for Chapter 117 to use $NO_x$-specific values because the mass emissions cap and trade program of Chapter 101 cannot use emission specifications for multiple pollutants to establish allocations for a single pollutant (i.e., $NO_x$).

30 TAC Chapter 117 - Preamble

Further, the changes to §117.206 add a new §117.206(c)(18) which specifies that if, and to the extent supported by, the commission's continuing scientific assessment of the causes of and possible solutions to HGA's ozone nonattainment status results in a determination that attainment can be reached with fewer $NO_x$ emission reductions from point sources concurrent with additional emission reduction strategies, then the executive director will develop a SIP revision involving revisions to the utility and non-utility ESADs for consideration at a commission agenda no later than June 1, 2002. In the event that the total $NO_x$ emission reductions from utility and non-utility point sources required for attainment is determined to be 80% from the 1997 emissions inventory baseline, the revised specifications shall be the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the specifications in the subparagraphs of the section. The commission reserves all rights to assign any additional $NO_x$ reduction benefits supported by the science evaluation to the relief of other control measures, including further $NO_x$ point source relief.

As has been EPA's legal position since 1975 and TNRCC's policy, the SIP can be revised to adjust requirements, based upon new information, technology, or science, provided the ultimate goal of the SIP is achieved and all requirements of the federal act are met. The mid-course review is a well defined approach that incorporates this policy. In order to ensure that the HGA area is in attainment by 2007 and that the controls to get there are the most cost-effective technology-based solutions possible, the commission has committed to performing a mid-course review (see the commission's enforceable commitment adopted in April 2000). The mid-course review process has already begun and will continue, ultimately resulting in a SIP revision submitted to EPA by May 1, 2004. There are planned opportunities throughout the process, as described in the SIP, to incorporate the latest information and make decisions. This effort will involve a thorough evaluation of all modeling, inventory data, and other tools and assumptions used to develop the attainment demonstration. It will also include the ongoing assessment of new technologies and innovative ideas to incorporate into the plan. For example, the commission is committed to developing an effective plan to minimize releases of reactive hydrocarbon emissions and the emissions of chlorine. To the extent that the science confirms the benefit from this program, then it is the intent of the commission to implement such a program through a SIP revision which will first offset $NO_x$ reductions from utility and non-utility sources down to the 80% (535 tpd) level. The commission, in its discretion, may allocate any additional benefit beyond 80% to other SIP strategies and/or to the point source $NO_x$ control strategy. Based upon current analysis, this 80% from utility and non-utility sources would result in a total reduction of not less than 535 tpd $NO_x$ emissions from utility and non- utility sources in the HGA area.

The alternate ESADs in §117.206(c)(18)(A) - (Q) were provided by the BCCA Appeal Group as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described later in this preamble in the first paragraph of the ANALYSIS OF TESTIMONY section, with the exception of the alternate ESAD for wood-fired boilers which is described later in this preamble under the heading of *ESAD - WOOD-FIRED BOILERS* in the ANALYSIS OF TESTIMONY section.

The $NO_x$ control levels in the alternate ESADs for different $NO_x$ point sources vary by source, but are intended to achieve an overall $NO_x$ point source reduction of 535 tpd, which is an approximate 80% reduction from the 1997 emission point source inventory of 668 tpd. The alternate ESADs also include a new category, pyrolysis reactors, that was previously included within the category of process heaters. This agreed reduction, which is contingent upon the outcome of the science evaluation discussed elsewhere in this preamble, was proposed for public comment as a part of that agreement. The commission solicited public comment on the BCCA Appeal Group's proposed alternate ESADs from all interested persons, including all owners and operators of $NO_x$ point sources and other stakeholders who are not members of the BCCA Appeal Group. The commission reserves all rights to assign any additional $NO_x$ reduction benefits supported by the science evaluation to the relief of other control measures, including further $NO_x$ point source relief. Comments received regarding this issue are addressed in the ANALYSIS OF TESTIMONY section of this preamble.

The changes to §117.206 also correct the reference in §117.206(f)(1)(C) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance" (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)), and revise §117.206(f)(4) to allow an owner or operator to use the alternative methods specified in §117.570 for purposes of complying with the EGF system cap in §117.210. The change will give the owners and operators of EGFs in HGA additional flexibility in meeting their system caps.

In addition, the changes to §117.206 revise §117.206(g)(2) by adding a reference to §117.205(h)(9) to ensure the continued availability of an exemption in BPA and DFW for stationary gas engines and turbines which operate less than 850 hours per year.

The changes to §117.206 also revise §117.206(h) by clarifying the intent of existing language concerning units in HGA which combust fuel or waste streams containing chemical-bound nitrogen and by moving the existing language into a new §117.206(h)(3). A new §117.206(h)(1) adds language to prohibit an owner or operator in HGA from derating equipment to take advantage of a less stringent ESAD in §117.206(c). The language allows derating from the maximum rated capacity on December 31, 2000 provided the TNRCC had received an administratively complete permit application (as determined by the executive director) before January 2, 2001, and the maximum rated capacity authorized by the permit issued on or after January 2, 2001 is no less than the maximum rated capacity represented in the permit application as of January 2, 2001. If the owner or operator increased the rated capacity after December 31, 2000, the higher of the two ratings would be used to determine the applicability of the ESAD in §117.206(c).

The changes to §117.206 also add a new §117.206(h)(2) to specify how units which can be classified as multiple unit types are treated for purposes of applying the ESADs. Specifically, a unit's classification is determined by the most specific classification applicable to the unit as of December 31, 2000. For example, a unit that is classified as a boiler as of December 31, 2000, but subsequently is authorized to operate as a BIF unit, shall continue to be classified as a boiler for the purposes of Chapter 117. In another example, a unit that is classified as a stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, shall be classified as a stationary gas-fired engine for the purposes of Chapter 117. The new §117.206(h)(2) is necessary to ensure that the intended emission reductions of the program are achieved and to clarify how units which can be classified as multiple unit types are treated in Chapter 117.

Finally, the changes to §117.206 revise §117.206(h)(3), which prohibits the owner or operator of units which combust fuel or waste streams containing chemical-bound nitrogen from directing these streams to flares or other units which are not subject to an ESAD. This is necessary to prevent circumvention due to the transfer of emissions associated with chemical-bound nitrogen from a unit under which these emissions would be controlled (i.e., a unit subject to an ESAD) to a unit that is not subject to the mass emissions cap and trade program (i.e., a unit without an ESAD) and therefore is uncontrolled. Section 117.206(h)(3) has been revised to make this intent clear. Also, the current §117.206(h)(3)(A) and (B) were deleted because the mass emissions cap and trade program does not include a provision allowing the opt-in of units to the program.

The changes to §117.206 also add a new subsection (i) which prohibits starting or operating any stationary diesel or dual-fuel engine in HGA for testing or maintenance between the hours of 6:00 a.m. and noon. This requirement will delay the emissions of $NO_x$, a key ozone precursor, until after noon in order to limit ozone formation. Section 117.206(i) allows operation for specific manufacturer's recommended testing requiring a run of over 18 consecutive hours, or to verify reliability of emergency equipment (e.g., emergency generators or pumps) immediately after unforeseen repairs. Routine maintenance such as an oil change is not considered to be an unforeseen repair since it can be scheduled outside the 6:00 a.m. to noon time period.

The changes to §117.210, concerning System Cap, modify the system cap requirements by adding another option to the last two sentences of §117.210(a). The new language excludes each EGF that generates electricity primarily for internal use, but that during 1997 and all subsequent calendar years transferred (or will transfer) that generated electricity to a utility power distribution system at a rate less than 3.85% of its actual electrical generation (which represents two weeks' worth of electrical generation per calendar year). These EGFs are base load units 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, the commission believes it is appropriate to exclude these units from the system cap.

The changes to §117.210 also add language in §117.210(a) to clarify that each EGF in the system cap is subject to the daily cap and appropriate 30-day cap of this section at all times and delete similar language in existing §117.210(c)(3). Additionally, the changes to §117.210 delete the specific emission specifications in the term $R_i$ (which appears in the figure in §117.210(c)(1)) and substitute a reference to the ESADs of §117.206(c). This change will add stationary diesel, gas-fired rich-burn, and gas-fired lean-burn engines to the list of equipment subject to the daily and 30-day system cap emission limitations for EGFs at industrial, commercial, and institutional combustion sources in HGA. In addition, the changes to §117.210 revise the term $H_i$ in the figure in §117.210(c)(1) to specify January 2, 2001 as the cutoff for administratively complete permit applications under Chapter 116 and start of construction of EGFs under a Chapter 106 permit by rule. This date is consistent with §101.353.

The changes to §117.210(c)(1) specify the calculation in this paragraph applies to a rolling 30-day average emission cap applicable during the months of July through September. The changes to §117.210 also revise the rolling 30-day average system cap for non-utility EGFs to take into account those industrial cogeneration units which have a maximum heat input rate in months other than July through September by adding a new §117.210(c)(2) to specify how to calculate a rolling 30-day average emission cap applicable during all months other than July through September. The change allows the owner or operator to substitute the system highest 30-day period in the nine months comprising the highest three consecutive months in each year of the 1997 - 1999 period. The existing §117.210(c)(2) is renumbered to become a new §117.210(c)(3).

In addition, the changes to §117.210 revise the rolling 30-day average emission cap of §117.210(c)(1), applicable during July - September, by modifying the method of determining level of activity for new EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in §101.350. The 180-day adjustment period addresses that period of time from first start-up to establishment of normal operating conditions for a new facility. In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period. A principal goal is to provide incentive to make emissions reductions. The commission believes that owners or operators who install and operate cleaner equipment should have the opportunity to fully integrate that equipment at a realistic level of operation that is representative of the demands that will be placed on the equipment. The commission believes that a five-year period to establish a baseline will allow this integration, while timely establishing the necessary emissions cap. This is consistent with the corresponding revisions to §101.353 which add the option of a five-year period to establish a baseline and the availability of an additional two-year period in extenuating circumstances.

Finally, the changes to §117.210 revise the rolling 30-day average emission cap of §117.210(c)(2), applicable during months other than July - September, by modifying the method of determining level of activity for new EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. For an EGF for which the system highest 30-day period in the first two years of operation occurs in months other than July - September, the owner or operator may substitute the system highest 30-day period in the six months comprising the highest three consecutive months in any two consecutive years in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in §101.350. The 180-day adjustment period addresses that period of time from first start-up to establishment of normal operating conditions for a new facility. In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period. A principal goal is to provide incentive to make emissions reductions. The commission believes that owners or operators who install and operate cleaner equipment should have the opportunity to fully integrate that equipment at a realistic level of operation that is representative of the demands that will be placed on the equipment. The commission believes that a five-year period to establish a baseline will allow this integration, while timely establishing the necessary emissions cap. This is consistent with the corresponding revisions to §101.353 which add the option of a five-year period to establish a baseline and the availability of an additional two-year period in extenuating circumstances.

The changes to §117.213, concerning Continuous Demonstration of Compliance, add a new §117.213(c)(1)(I) which requires installation of a CEMS or PEMS to measure $NO_x$ from FCCUs in HGA. While the commission expects that $NO_x$ emissions from these FCCUs (including CO boilers, CO furnaces, and catalyst regenerator vents) will ultimately be controlled through injection of a chemical reagent, and therefore would already be required under the existing §117.213(c) to install a CEMS or PEMS to measure $NO_x$, the change is necessary to ensure that relatively large $NO_x$ emissions from these sources are monitored for purposes of the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3.

The changes to §117.213 also revise §117.213(i) to change a reference from §117.203(a)(6)(B) to §117.205(h)(2) due to the deletion of the redundant exemption in §117.203(a)(6)(B) for operation of stationary gas engines and turbines which operate less than 850 hours per year, and add a reference to §117.203(a)(11) and (12) due to the addition of these new exemptions based on low annual hours of operation. In addition, the changes to §117.213 specify that any run time meter installed on or after October 1, 2001 must be non-resettable to improve enforceability of the limit on hours of operation under the exemptions. This change will prevent an owner or operator from resetting a run time meter, whether deliberate or inadvertent, and making the actual number of hours of operation difficult to verify. Finally, the changes to §117.213 also revise §117.213(l) by replacing the wording "pursuant to" with "under" for consistency with the commission's style guidelines.

The change to §117.214, concerning Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration, adds a new §117.214(a)(2) which references the run time meter requirements of §117.213(i) for stationary diesel engines claimed exempt using the exemption of §117.203(a)(6)(D), (11), or (12). This change is necessary to facilitate recordkeeping to ensure that operation for testing or maintenance purposes is limited to 52 hours per year, based on a rolling 12-month average, and to document that all other engine operation occurs only during emergency situations, as defined in §117.10. The existing language becomes §117.214(a)(1) as a result of the addition.

The changes to §117.219, concerning Notification, Recordkeeping, and Reporting Requirements, revise §117.219(b) and (c) to more accurately direct testing results and notifications of initial demonstration of compliance testing to the proper agency and local program representatives. Specifically, the revisions to §117.219(b) specify that verbal notification of initial demonstration of compliance testing and CEMS or PEMS performance evaluation should be made to the appropriate regional office and any local air pollution control agency having jurisdiction, rather than the executive director. In addition, the revisions to §117.219(c) specify that a copy of the initial demonstration of compliance testing should be provided to the Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction, rather than the executive director. Any testing results sent to the Office of Compliance and Enforcement should include the notation "Engineering Services Team (MC 171)" to help ensure accurate mail delivery.

In addition, the changes to §117.219 add a new §117.219(f)(10) which requires records of each time a stationary diesel or dual-fuel engine in HGA is operated for testing and maintenance in order to ensure compliance with the restriction on operating hours for testing and maintenance and revise §117.219(f)(6) to add a reference to the engine exemptions of §117.203(a)(6)(D), (11), or (12) described earlier in this preamble. The changes to §117.219 also revise §117.219(f)(6) by adding a requirement that the owner or operator keep records of the purpose of engine operation, and if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation.

The changes to §117.471, concerning Applicability, add stationary gas turbines and associated duct burners to the list of equipment subject to the requirements of Subchapter D, Division 2, at minor sources in HGA, and update a reference to this division to reflect its new title.

The changes to §117.473, concerning Exemptions, revise §117.473(a) by updating a reference to Subchapter D, Division 2, to reflect its new title and by adding a reference to §117.478(c) and §117.479(h) - (j) because these requirements apply to some engines which are otherwise exempt; revise §117.473(a)(2) by changing "engines" to "stationary engines" for clarification; and revise §117.473(a)(2)(A) by changing "50 hp or less" to "less than 50 hp" for consistency with the federal Tier 2/Tier 3 diesel engine standards.

In addition, the changes to §117.473 replace the existing exemption in §117.473(a)(2)(E) for engines operated exclusively for firefighting and/or flood control with an exemption for engines used exclusively in emergency situations, as defined in the new §117.10(14). However, operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average. Fifty-two hours per year allows up to one hour per week of maintenance or testing, which is a reasonable upper bound for this type of operation. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service in HGA on or after October 1, 2001 is ineligible for this exemption. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in §116.10 and 40 CFR §60.15, respectively, and the term "relocated" means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account. New and existing diesel engines will continue to be eligible for exemption under §117.473(a)(2) if they are used for one or more of the following purposes: research and testing; performance verification and testing; solely to power other engines or gas turbines during start-ups; in response to and during the existence of any officially declared disaster or state of emergency; or directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals. In addition, existing engines will be eligible for the exemption for use exclusively in emergency situations, as described earlier in this preamble.

The changes to §117.473 also revise the existing §117.473(a)(2)(H), which exempts engines that operate less than 100 hours per calendar year, to exempt engines that operate less than 100 hours per year, based on a rolling 12-month average, for consistency with the new §117.203(a)(11) described earlier in this preamble. The changes to §117.473(a)(2)(H) also exclude any modified, reconstructed, or relocated diesel engine placed into service on or after October 1, 2001. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in §116.10 and 40 CFR §60.15, respectively, and the term "relocated" means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account. In addition, the changes to §117.473 delete the reference to §117.479(h) in §117.473(a)(2)(H) due to the addition of a reference to §117.479(h) in §117.473(a), as described earlier in this preamble.

The changes to §117.473 also replace the existing exemption for diesel engines in §117.473(a)(2)(I) with an exemption for new, modified, reconstructed, or relocated stationary diesel engines placed into service in HGA after October 1, 2001 which operate less than 100 hours per calendar year, based on a rolling 12-month average. To qualify for this exemption, the engine must meet the EPA's Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines listed in 40 CFR §89.112(a), Table 1 and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this exemption, the terms "modification" and "reconstruction" have the meanings defined in §116.10 and 40 CFR §60.15, respectively, and the term "relocated" means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account.

In addition, the changes to §117.473 add a new §117.473(a)(3) that exempts stationary gas turbines rated at less than 1.0 MW which were in operation on or before October 1, 2001. This exemption is necessary because the ESAD (described later in this preamble) is based on combustion modifications (dry low-$NO_x$ burners (DLN) or water injection) which are not available as retrofits for some older gas turbines rated at less than 1.0 MW. Since these combustion modifications are readily available for new gas turbines rated at less than 1.0 MW, the exemption only applies to these smaller units with an initial start of operation on or before October 1, 2001.

The changes to §117.473 also delete the exemption in §117.473(c) for small (ten MW or less) electric generating units which are registered under a standard permit. At the time of adoption of this exemption on December 6, 2000, the proposed standard permit for small electric generating units (November 2000) contained output-based emission limits at least as clean as new central power plants, thereby having a minimal impact on the HGA Attainment Demonstration SIP. Subsequently, the commission has received information that applying output-based emission limits at this level to small electric generating units may not be feasible because of differences in operating efficiency between small (ten MW and less) and larger electric generating units. Therefore, the commission believes it is necessary to delete the exemption to ensure that there is no greater impact of $NO_x$ emissions on HGA.

According to a comment received during previous rulemaking, emergency generators usually do not operate more than 100 hours per year. (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 585)). However, engines which are used to shave peak electric demand tend to operate on hot days that coincide with higher probability of ozone exceedances. Therefore, it is necessary to establish emission specifications for these engines and, if they are located at a site where the collective design capacity to emit $NO_x$ is ten tons or more per year, include them in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3.

The changes to §117.475, concerning Emission Specifications for Attainment Demonstrations, revise §117.475(a) and (b) to clarify that "any applicable permit limit" refers to any permit issued before January 2, 2001, any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, or any limit in a permit by rule under which construction commenced by January 2, 2001. The changes to §117.475 also replace a reference in §117.475(b)(1) to boilers, process heaters, and engines with "unit" for consistency with the revisions to the definition of this term in §117.10, and update a reference in the renumbered §117.475(c)(4) due to the addition of the new §117.475(c)(3).

In addition, the changes to §117.475 revise §117.475(c) to clarify that the $NO_x$ emission specifications of §117.475 shall be used in conjunction with §117.475(a) to determine allocations for the mass emissions cap and trade program of Chapter 101, or in conjunction with §117.475(b) to establish unit-by-unit emission specifications, as appropriate. This change is necessary because the existing language could give the impression that all units must meet the $NO_x$ emission specifications of §117.475 on a unit-by-unit basis.

The changes to §117.475 also revise §117.475(c)(2) to establish an ESAD of 0.60 g $NO_x$/hp-hr for stationary engines which are fired on landfill gas. The existing ESAD of 0.50 g $NO_x$/hp-hr is based on the use of flue gas cleanup and remains the ESAD for stationary engines not fired on landfill gas. However, it has come to the commission's attention that landfill gas contains siloxanes which rapidly poison the catalyst of flue gas cleanup controls. The revised ESAD for stationary engines which are fired on landfill gas is based upon combustion modifications and is necessary to ensure that the ESAD for these engines is technically feasible.

The changes to §117.475 also add a new §117.475(c)(3) which establishes an emission specification for dual-fuel engines. The existing §117.475(c)(3) becomes §117.475(c)(6) as a result of the previously discussed revisions, and the reference to paragraphs (1) - (2) is revised to reference paragraphs (1) - (5).

The changes to §117.475 also add a new §117.475(c)(4) which establishes emission specifications for stationary diesel engines which are based on the EPA's Tier 1, Tier 2, and Tier 3 emission standards for non-road diesel engines listed in 40 CFR §89.112(a), Table 1. Because the Tier 2/Tier 3 standards and some of the Tier 1 standards are expressed in terms of NMHC+$NO_x$, the commission used *Exhaust Emission Factors for Nonroad Engine Modeling - Compression Ignition, Report No. NR-009A*, (revised June 15, 1998) to split the combined NMHC+$NO_x$ standards into single pollutant emission factors.

In addition, the changes to §117.475 add a new §117.475(c)(5) which establishes an ESAD of 0.15 lb $NO_x$ per MMBtu heat input (about 42 parts per million by volume (ppmv), dry at 15% oxygen ($O_2$)) for stationary gas turbines and duct burners used in turbine exhaust ducts at minor sources of $NO_x$ located within the HGA ozone nonattainment area. The ESAD is consistent with the current RACT limit of 42 ppmv. It is anticipated that combustion modifications such as DLN or water injection will be necessary to achieve the ESAD. Because neither DLN nor water injection are available on some older gas turbines rated at less than 1.0 MW, the ESAD does not apply to these smaller units if they have an initial start of operation on or before October 1, 2001. Finally, the changes to §117.475 add new subsections (d) - (f) in order to address circumvention issues. These new subsections for minor sources are consistent with §117.206(h) for major sources.

The changes to §117.478, concerning Operating Requirements, replace references in §117.478(a), (b), and (b)(3) to boilers, process heaters, and engines with "unit" for consistency with the revision to the definition of this term in §117.10.

The changes to §117.478 also add a new subsection (c) which prohibits starting or operating any stationary diesel or dual-fuel engine in HGA for testing or maintenance between the hours of 6:00 a.m. and noon. This requirement will delay the emissions of $NO_x$, a key ozone precursor, until after noon in order to limit ozone formation. Section 117.478(c) allows operation for specific manufacturer's recommended testing requiring a run of over 18 consecutive hours, or to verify reliability of emergency equipment (e.g., emergency generators or pumps) immediately after unforeseen repairs. Routine maintenance such as an oil change is not considered to be an unforeseen repair since it can be scheduled outside the 6:00 a.m. to noon time period.

The changes to §117.479, concerning Monitoring, Recordkeeping, and Reporting Requirements, replace references in §117.479(a)(1), (e), and (e)(1), (2), (5) and (6) to boilers, process heaters, and engines with "unit" for consistency with the revision to the definition of this term in §117.10; revise §117.479(d) to update a reference to §117.534 to reflect its new title; and revise §117.479(h) to add a reference to §117.473(a)(2)(E) and (I) to require records of hours of operation for stationary diesel engines claimed exempt based on low annual hours of operation or use exclusively in emergency situations. The changes to §117.479 also revise §117.479(h) by adding a requirement that the owner or operator keep records of the purpose of engine operation, and if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation. Finally, the record retention time of §117.479(h) was revised from two years to five years for consistency with §117.479(f) and (j).

In addition, the changes to §117.479 add a new §117.479(i), which requires run time meters for stationary diesel engines claimed exempt due to low annual hours of operation or use exclusively in emergency situations. For engines claimed exempt due to low annual hours of operation, this change is necessary to facilitate recordkeeping to document that the engines qualify for the exemption. For engines operated exclusively in emergency situations, this change is necessary to facilitate recordkeeping to ensure that operation for testing or maintenance purposes is limited to 52 hours per year, based on a rolling 12-month average, and to document that all other engine operation occurs only during emergency situations, as defined in §117.10. The changes to §117.479 also add a new §117.479(j) which requires records of each time a stationary diesel or dual-fuel engine in HGA is operated for testing and maintenance in order to ensure compliance with the restriction on operating hours for testing and maintenance.

The changes to §117.510, concerning Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas, correct the references in §117.510(a)(2)(A)(ii)(II) and (b)(2)(A)(i)(II)(-b-) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)). The changes to §117.510 also revise §117.510(a)(1)(A)(i) and (c)(1)(A)(i) by replacing the wording "pursuant to" with "under" for consistency with the commission's style guidelines, and revise §117.510(c)(2)(A)(ii)(II) by replacing the wording "pursuant to" with "in accordance with," also for consistency with the commission's style guidelines.

In addition, the changes to §117.510 revise §117.510(c)(2)(A)(i) to clarify the intended meaning of "time of installation of emission controls" regarding emissions monitors. Specifically, the changes clarify that if flue gas cleanup (such as selective catalytic reduction (SCR) or selective non- catalytic reduction (SNCR)) is installed, then the emissions monitors required by §117.114 must be installed at the time of installation of flue gas cleanup or by March 31, 2005 (whichever occurs first), regardless of whether or not combustion controls are later installed. If only combustion controls are installed on a unit, then the emissions monitors required by §117.114 must be installed by March 31, 2005. If installation of emission controls (whether combustion controls, flue gas cleanup, or both) has not begun by March 31, 2005 on a unit for which §117.114 requires emissions monitors, then the required emissions monitors must be installed by March 31, 2005.

The changes to §117.510 also revise §117.510(c)(2)(B) by adding new clauses (i) and (ii) which specify the dates by which the owner or operator of EGFs in HGA must submit to the executive director the certification of level of activity, $H_i$, specified in §117.108. The new §117.510(c)(2)(B)(i) requires the owner or operator of EGFs in HGA to make this submission no later than June 30, 2001; however, this date is consistent with 30 TAC §101.360, concerning Level of Activity Certification, and has been communicated to the two affected companies. The existing language in §117.510(c)(2)(B) becomes clause (iii) as a result of the changes.

Additionally, the percent reductions in the renumbered §117.510(c)(2)(B)(iii)(I) and (II) were changed from 46% and 92% to 47% and 95%, respectively. The changes reflect that a higher percentage of the required electric utility $NO_x$ reduction of §117.106(c)(1) will be accomplished by 2004 if the total amount of required reduction by 2007 is reduced as adopted in §117.106(c)(1). The amount of reduction required of PUC-regulated utilities by 2004 remains unchanged. The major utility in HGA is currently implementing a plan which will achieve all but 5% of the required reduction in the area by 2004.

In addition, the changes to §117.510 add a new §117.510(c)(2)(D) which specifies that the owner or operator must comply with the emission reduction requirements of the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 as soon as practicable, but no later than the appropriate dates specified in that program.

Also, the changes to §117.510 add a new §117.510(c)(2)(E) which specifies the dates by which owners or operators of each EGF must comply with the requirements of §117.108 if alternate emission specifications are implemented under §117.106(c)(5).

The changes to §117.520, concerning Compliance Schedule for Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas, correct the reference in §117.520(a)(3)(A)(ii)(III) to §117.570 to reflect the recent title change of this section from "Trading" to "Use of Emissions Credits for Compliance." (See the January 12, 2001 issue of the *Texas Register* (26 TexReg 631)). The changes to §117.520 also revise §117.520(c)(2)(A)(ii)(I), (C)(i), and (D)(i) by replacing the wording "pursuant to" with "in accordance with" for consistency with the commission's style guidelines.

In addition, the changes to §117.520 revise §117.520(c)(2)(A)(i) to correct a reference from "§117.114" to "§117.214" and add run time meters (for stationary diesel engines claimed exempt in HGA) to the compliance schedule, and clarify the intended meaning of "time of installation of emission controls" regarding emissions monitors. Specifically, the changes clarify that if flue gas cleanup (such as SCR or SNCR) is installed, then the emissions monitors required by §117.214 must be installed at the time of installation of flue gas cleanup or by March 31, 2005 (whichever occurs first), regardless of whether or not combustion controls are later installed. If only combustion controls are installed on a unit, then the emissions monitors required by §117.214 must be installed by March 31, 2005. If installation of emission controls (whether combustion controls, flue gas cleanup, or both) has not begun by March 31, 2005 on a unit for which §117.214 requires emissions monitors, then the required emissions monitors must be installed by March 31, 2005.

The changes to §117.520 also revise the system cap compliance schedule for non-utility EGFs in §117.520(c)(2)(B)(iii). Currently, the rules include the following staged implementation schedule for compliance with the HGA ESADs. First, 44% of the total reductions required to comply with the ESADs are required by March 31, 2004, with the next 45% of the reductions required by March 31, 2005. The final reductions are required by March 31, 2007. The changes to §117.520(c)(2)(B)(iii) would allow smaller annual reductions in emissions spread over a five-year period. The commission adopted this change to allow the affected industries more options for planning and implementing incremental reductions in emissions. The amendment will not affect the March 31, 2007 final compliance date nor will it increase final emission rates, and it will still achieve the final emission reductions as required by the SIP.

Further, the new §117.520(c)(2)(C) specifies an emission reduction schedule that would apply if the alternative emission specifications of §117.206(c)(18) are implemented.

In addition, the changes to §117.520 delete an incorrect reference to non-EGFs in existing §117.520(c)(2)(D), renumbered as §117.520(c)(2)(E). This change is necessary because the owners or operators of EGFs and non-EGFs alike must comply with the emission reduction requirements of the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 as soon as practicable, but no later than the appropriate dates specified in that program. Also, the existing §117.520(c)(2)(C) is renumbered as §117.520(c)(2)(D).

Finally, the changes to §117.520 add a new §117.520(c)(2)(F) which specifies the compliance schedule for the restrictions on hours of operation for testing or maintenance of stationary diesel and dual-fuel engines in HGA.

The changes to §117.534, concerning Compliance Schedule for Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources, revise §117.534(1)(A) and (2)(A) to add run time meters (for stationary diesel engines claimed exempt in HGA) to the compliance schedule, and clarify the intended meaning of "time of installation of emission controls" regarding emissions monitors. Specifically, the changes clarify that if flue gas cleanup (such as SCR or SNCR) is installed, then the emissions monitors required by §117.479 must be installed at the time of installation of flue gas cleanup or by March 31, 2005 (whichever occurs first), regardless of whether or not combustion controls are later installed. If only combustion controls are installed on a unit, then the emissions monitors required by §117.214 must be installed by March 31, 2005. If installation of emission controls (whether combustion controls, flue gas cleanup, or both) has not begun by March 31, 2005 on a unit for which §117.479 requires emissions monitors, then the required emissions monitors must be installed by March 31, 2005.

In addition, the changes to §117.534 also revise §117.534(1)(B)(i) and (C)(i) and (2)(B)(i) by replacing the wording "pursuant to" with "in accordance with" for consistency with the commission's style guidelines. The changes to §117.534 also add a new §117.534(1)(E) and (2)(D) which specify the compliance schedule for the restrictions on hours of operation for testing or maintenance of stationary diesel and dual-fuel engines in HGA. Finally, the revisions update the title of §117.534 and Subchapter D, Division 2, to reflect the addition of requirements for new stationary gas turbines at minor sources in HGA.

The changes to §117.570, concerning Use of Emissions Credits for Compliance, create a new §117.570(b) to provide flexibility for owners or operators of EGFs which are subject to the system caps of §§117.108, 117.138, or 117.210. Specifically, the new §117.570(b) allows an owner or operator to meet the emission control requirements of these system caps by complying with the requirements of Chapter 101, Subchapter H, Division 5 of this title (relating to System Cap Trading) or by obtaining an ERC, mobile emission reduction credit (MERC), DERC, or mobile discrete emission reduction credit (MDERC) in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title, unless there are federal or state regulations or permits under the same commission account number which contain a condition or conditions precluding such use.

The changes to §117.570 also revise §117.570(a) to correct references to the titles of divisions in Chapter 101, Subchapter H; relocate the last sentence of §117.570(a) to a new §117.570(c); and reletter the existing §117.570(b) as §117.570(d).

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 (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

Chapter 117 is an applicable requirement under 30 TAC Chapter 122; therefore, 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 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. A "major environmental rule" means a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure and that may adversely affect in a material way the economy, 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 stationary diesel and dual- fuel engines in the HGA ozone nonattainment area. The amendments will also require new stationary gas turbines and duct burners at minor sources of $NO_x$ in HGA to meet emission specifications in order to reduce $NO_x$ emissions and ozone air pollution. In addition, the amendments will improve implementation of the existing Chapter 117 by correcting typographical errors, updating cross-references, clarifying ambiguous language, adding flexibility, amending requirements to achieve the intended emission reductions of the program, and deleting the exemption for small (ten MW or less) electric generating units which are registered under a standard permit. Finally, the amendments will revise the ESADs for electric utilities and landfill gas-fired stationary engines, revise the emission reduction schedule for sources other than electric utilities, and provide for alternate ESADs in the event that the TNRCC's continuing scientific assessment of the causes of and possible solutions to HGA's ozone nonattainment status results in a determination that attainment can be reached with fewer $NO_x$ emission reductions from point sources concurrent with additional emission reduction strategies. 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 stationary diesel and dual-fuel engines at sites in the HGA ozone nonattainment area with a collective design capacity to emit (from units with ESADs) $NO_x$ in amounts greater than or equal to ten tpy, as well as stationary diesel and dual-fuel engines at sites with a collective design capacity 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, including the discussion in the PUBLIC BENEFIT AND COSTS section of the proposal (26 TexReg 4400). The remaining amendments in this rulemaking are intended to provide flexibility and clarify the commission's intent that the HGA ozone nonattainment area is able to demonstrate attainment and these amendments are not expected to 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 implement requirements of the FCAA, 42 USC, §7410. 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 §7410 does not require specific programs, methods, or reductions in order to meet the standard, 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 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. Thus, while specific measures are not generally required, the emission reductions are required. States are not free to ignore the requirements of §7410, and must develop programs to assure that the nonattainment areas of the state will be brought into attainment on schedule.

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 (1997). 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, 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. 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 §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. Section 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 §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 §7511a(f) exemption from $NO_x$ measures for HGA expired on December 31, 1997. The expiration of the exemption under §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 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.

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 was not developed solely under the general powers of the agency, but was specifically developed to meet the NAAQS established under federal law and authorized under 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.

No comments were received during the comment period regarding the draft RIA determination.

TAKINGS IMPACT ASSESSMENT

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. Texas Government Code, §2007.003(b)(4), provides that Chapter 2007 does not apply to these adopted rules, because 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 action 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.

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 ozone levels in the HGA nonattainment area. Consequently, these rules meet the exemption in §2007.003(b)(13).

The commission included elsewhere in this preamble its reasons for proposing this strategy and 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 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.

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'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 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 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. 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 public comment period regarding the CMP consistency review.

HEARINGS AND COMMENTERS

The commission held public hearings on this proposal at the following locations: June 13, 2001, in Galveston; June 14, 2001 in Rosenberg and Houston; June 15, 2001, in Austin; and July 2, 2001 in Houston. The comment period closed on July 2, 2001.

Twenty-eight commenters submitted testimony on the proposal. Harris County Municipal Utility District 368 and Shrader Engineering Company submitted joint oral comments and will be referred to as Shrader. Texas Instruments (TI) supported the proposed revisions to Chapter 117. Abitibi- Consolidated Inc. (Abitibi); Baker Botts L.L.P. on behalf of Texas Industry Project (TIP); BASF Corporation (BASF); BP Amoco (BP); BCCA; BCCA Appeal Group (BCCAAG); City of Houston (Houston); Dow Chemical Company (Dow); Dynegy, Incorporated (Dynegy); Energy Developments, Incorporated (EDI); Environmental Defense (ED); Environmental Resources Management (ERM); EPA; ExxonMobil Corporation (ExxonMobil); Galveston-Houston Association for Smog Prevention (GHASP); Haldor Topsoe, Incorporated (Topsoe); IT Corporation (IT); National Aeronautics and Space Administration (NASA); Reliant; Safety-Kleen (Deer Park), Incorporated (Safety-Kleen); Sempra Energy Resources (Sempra); Shrader; Sierra Club - Houston Regional Group (Sierra-Houston); Texas Chemical Council (TCC); Texas Department of Transportation (TxDOT); Thermal Energy Cooperative (TECO); and an individual supported the proposed revisions but suggested changes or clarifications.

BCCAAG supported the comments submitted by TIP. Dow supported the comments submitted by BCCA and TIP. Dynegy supported the comments submitted by BCCAAG.

ANALYSIS OF TESTIMONY

In January 2001, BCCAAG and others filed suit against the commission challenging the December 6, 2000 SIP revision for HGA and five of the ten sets of rules associated with that SIP revision. As part of that lawsuit, the plaintiffs sought a temporary injunction to stay the effectiveness of these five sets of rules and for the commission to withdraw the SIP from EPA consideration. A hearing on this request was held before Judge Margaret Cooper, Travis County District Court, Texas, on May 14 - 18, 2001. Before that hearing was completed, an agreement in principle was reached to settle the lawsuit, and a Consent Order was entered by Judge Cooper which includes certain specific items included in the SIP revision and rules in Chapters 101 and 117 proposed by the commission on May 30, 2001 (see the June 15, 2001 issue of the *Texas Register* (26 TexReg 4380 and 4400, respectively)). In support of its position that certain testimony in that hearing establishes the infeasibility of the $NO_x$ reduction and that the air dispersion modeling used by the commission is not reliable, BCCAAG submitted the transcript from the hearing as comments on these proposals. Although the hearing was not completed before a settlement in principle was reached, the hearing transcript included testimony from BCCAAG's witnesses as well as the commission's witnesses, and therefore presents both sides of, or two different opinions on, some of the issues. Many of the documents introduced as exhibits in the hearing predate the rule changes and SIP revision proposed by the commission in the June 15, 2001 issue of the *Texas Register* and do not specifically address these rule changes and SIP revision. In addition, BCCAAG submitted as comments its First Amended Petition in the lawsuit and BCCA's comments from the earlier SIP, both of which were created before the settlement in principle was reached. While BCCAAG supports the substitution of new ESADs and other rule language from the Consent Order, it is not clear as to what other specific changes to the SIP and rules should be considered in this adoption in response to these particular comments.

*GENERAL COMMENTS*

TI supported the proposed revisions to Chapter 117.

The commission appreciates the support.

BCCA and ED resubmitted their September 25, 2000 comment letters concerning rulemakings and the associated SIP revision which were adopted by the commission on December 6, 2000, while BCCAAG incorporated by reference the September 25, 2000 BCCA comment letter. BCCA and ED had initially submitted these comment letters during the comment period for these previous rulemakings and associated SIP revision. BCCAAG also resubmitted a September 25, 2000 comment letter from Enterprise Products Operating L.P. (Enterprise) concerning rulemakings and associated SIP revision which were adopted by the commission on December 6, 2000. Enterprise had initially submitted this comment letter during the comment period for these previous rulemakings and associated SIP revision.

The comments in the BCCA, ED, and Enterprise comment letters dated September 25, 2000 were addressed in the ANALYSIS OF TESTIMONY sections of the preambles to these earlier rulemakings and SIP revisions which were published in the January 12, 2001 issue of the *Texas Register*.

Sierra-Houston referenced, but did not submit, 24 letters, two memoranda, and one paper dated from August 2, 1999 through February 23, 2001 which it reported as being information previously submitted to the commission. Sierra-Houston requested that this information be considered during the current rulemakings and SIP revisions. One individual referenced but did not submit previous letters addressing Houston SIP issues.

Sierra-Houston and the one individual did not identify the relationship between its previous submissions and any rulemaking or SIP revision for which it had previously submitted the referenced 24 letters, two memoranda, and one paper. Consequently, it is unclear whether this information had been submitted during the comment period for previous rulemakings and SIP revisions, and if so, which ones, or whether this information had been submitted in a manner unrelated to proposed rulemaking, and if so, the project(s) for which the information was submitted in order to allow the commission to locate the information. If Sierra-Houston and the individual submitted this information during the comment period for previous rulemakings and SIP revisions, then it was 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*. If, however, Sierra-Houston and the individual had not submitted this information during the comment period for previous rulemakings and SIP revisions, then it is unclear how the commission is to respond to this information without this information available to the commission during the comment period for the current rulemakings and SIP revisions.

*TECHNICAL FEASIBILITY - GENERAL COMMENTS*

As discussed earlier in this preamble, BCCAAG submitted the entire transcript of the May 14 - 18, 2001 temporary injunction hearing held before Judge Margaret Cooper, Travis County District Court, concerning the lawsuit styled BCCA Appeal Group, et al v. TNRCC. Regarding technical feasibility of meeting the existing ESADs, a witness, Doug Deason (Deason), testified that there is "extensive" experience with combustion modifications to reduce $NO_x$, both in the United States and in other countries.

The commission agrees that the frame of reference for retrofit experience is not limited to the United States, and that there is extensive experience with combustion modifications to reduce $NO_x$.

BCCA and BCCAAG expressed doubts about the technical feasibility of the 90% reductions of the existing ESADs which were adopted December 6, 2000. BCCA and BCCAAG stated that "in sworn testimony admitted into evidence in the pending litigation, duly qualified experts have further established the infeasibility of the 90% reduction" and that the existing ESADs should be removed from the SIP in favor of alternate ESADs which would achieve an 80% $NO_x$ reduction from point sources. A witness, Randy Hamilton, (Hamilton), testified that the technical feasibility of the point source rule is not uncertain, but that "it is technically feasible to achieve the point source reductions required by the rule." Hamilton further testified that he believes that "the technical feasibility determinations come down to cost feasibility... on individual units."

The commission disagrees with the commenters and agrees with Hamilton. In the December 2000 adoption of the existing ESADs to achieve approximately 90% reductions in $NO_x$ point source emissions, the commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of the existing ESADs. The commission determined that the various controls which can be used to meet the ESADs have a proven performance experience and agreed with BP that the 90% reductions are technically feasible. A detailed explanation of how the commission reached these conclusions is given in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524). BCCA and BCCAAG are mistaken in their claim that "duly qualified experts have further established the infeasibility of the 90% reduction." In fact, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, Judge Margaret Cooper, Travis County District Court, has not even heard all of the testimony in the May 14 - 18, 2001 temporary injunction hearing, and obviously has not issued a ruling on the temporary injunction requested by BCCAAG, et al. Further, the trial on the merits of the case has not even begun. The commission is confident that if and when litigation resumes, the evidence will demonstrate that the existing ESADs which were adopted December 6, 2000 are technically feasible.

Deason testified that with good design of new units, combustion controls "typically get very close to achieving vendors' guarantees and the maximum potential of the equipment."

The commission agrees that good design is critical to achieving the desired emission reductions.

Deason testified that in some cases, the optimum burner is not available and as a result, the unit may not achieve the technology potential of burner retrofits.

Combustion controls are developing dynamically, achieving teen and even single digit $NO_x$ ppm in a growing number of applications. 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 Collin County, Texas, this is currently achieving 0.04 lb/MMBtu, with expectations of even better performance. Other control options are also available. Burner replacement is but one of many combustion control options.

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. For example, replacement or consolidation of existing equipment, reduced fuel firing, and shutdown of existing equipment (particularly for marginally economic equipment and production lines) are possible options for reducing $NO_x$. 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 select a combination of the two approaches.

Deason testified that ExxonMobil plants in other ozone nonattainment areas (Baton Rouge, Southern California, etc.) have units that have been retrofitted with Tier I controls, and none are meeting the ESADs. Another witness, Jess McAngus (McAngus), testified that Tier I controls alone are insufficient to meet the ESADs.

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. Therefore, it is no surprise that the ESADs are in many cases more stringent than the emission specifications in areas such as Baton Rouge, which is classified as a serious ozone nonattainment area (as compared to Houston's classification as a severe ozone nonattainment area), or southern California, which has a lower percentage of point source $NO_x$ emissions than Houston.

As noted in the preamble to the Chapter 117 revisions which were proposed in the August 25, 2000 issue of the *Texas Register*, 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 August 25, 2000 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)).

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. The ESADs for many units are not based on Tier I, but rather are based on Tier III. Deason did not indicate what emission specification the units at ExxonMobil plants in other ozone nonattainment areas were designed to achieve. If the units were specifically designed to meet a less stringent requirement, it would not be logical to expect that the units would necessarily meet a more stringent ESAD.

The capabilities of combustion modifications are well documented in the literature, including the $NO_x$ control literature cited in the cost note sections of the preamble to the Chapter 117 revisions which were proposed in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275). 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. 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 existing ESADs. In fact, one vendor has provided several dozen retrofits, primarily on gas-fired boilers in commercial service today, achieving $NO_x$ levels of nine ppm or less. Another vendor provided a list of 12 boilers in California, ranging in size from 21 to 70 MMBtu/hr, which it equipped with low-$NO_x$ burners achieving $NO_x$ levels of nine ppm or less. Five of the 12 boilers were retrofits, ranging in size from 21 to 64 MMBtu/hr. However, the vendor has stated (and the vendor's data supports) that its low-$NO_x$ burners can achieve $NO_x$ levels of nine ppm or less on both new boilers and retrofits. 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 which are 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.

Deason testified that Tier I for one point source is not very transferrable to another because each unit is different, with different spacing between equipment and different duty requirements. Deason stated that an individual engineering design analysis is necessary and commented that as an example, ExxonMobil has over 20 different types of ethylene plant pyrolysis reactors. Deason stated that the same principle of individual engineering design analysis applies to ExxonMobil's process heaters and furnaces, gas turbines, and boilers. Hamilton testified that one person's opinion is that while 800 units may require flue gas cleanup, only a lesser number of designs (perhaps 100) will be necessary because among all of these units there is a certain number of essentially very similar looking units, and this commonality will reduce the number of detailed engineering studies necessary.

The commission agrees that detailed engineering design analysis is necessary. The commission also agrees that the commonality between some units is expected to reduce the number of detailed engineering studies necessary.

Deason testified that field experience has not adequately demonstrated that retrofit Tier III technology will meet the ESADs. McAngus testified that Tier II controls alone are insufficient to meet the ESADs, and that Tier III controls alone are insufficient to meet the ESADs. Hamilton testified that "the patents for SCR were issued in the 1950s. Commercial use of SCR goes back at least to the 1970s in Japan, and expanded greatly in Japan and West Germany... in the 1980s. SCR began to be commercially demonstrated in the United States during the second half of the 1980s, and it continues to grow rapidly in the United States, as more... new units and existing units have SCR applied." Hamilton also testified that "in 1997 the Institute of Clean Air Companies counted more than 500 {SCR} units operating worldwide. More recently, I understand that one company has an experience list of about 500 units in the United States right now." Hamilton further testified that "in Europe there are more than 500 diesel engines with SCR," and some of these are retrofits. Hamilton also testified that the relatively limited number of retrofitted SCRs is not a concern because "the retrofits are technically feasible, and what we have seen, in looking at the history of... air emission controls over the years is that application of technology to a given level follows the regulations, rather than the other way around. When the emission standards are set at a particularly stringent level, technology has responded and new examples {of units meeting the emission standards} appear." Hamilton testified that in the five major source categories, the commission found examples of equipment retrofitted to achieve the ESADs, representing more than 95% of the emissions, although the commission did not identify examples of retrofits for all of the different subcategories of point sources. Hamilton also testified that for a number of major categories, the commission was aware of examples of retrofitted units which were controlled to at or below the ESADs.

As noted in the response to a previous comment, the capabilities of Tier I combustion modifications are well documented. 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 in question. Further, the distinctions between new and retrofit applications involve issues of cost rather than technical feasibility.

The literature cited in the preamble to the December 2000 Chapter 117 rule revisions 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 the January 12, 2001 issue of the *Texas Register* (26 TexReg 706), 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. In summary, Tier I, II, and III are well-demonstrated retrofit technologies and have been shown to meet the ESADs on individual units.

Deason testified that some units, regardless of whether they are ExxonMobil's, have already met the ESADs if they are "not combustion-only controlled."

The witness's testimony indicates acknowledgment that compliance with the ESADs has already been demonstrated at some units equipped with Tier II or Tier III controls. The commission agrees that the ESADs are technically feasible.

McAngus testified that no non-utility unit in HGA has been retrofit to meet the ESADs, based on his search of HGA and a review of the references listed in the December 6, 2000 adoption preamble.

As noted earlier in this preamble, the frame of reference for retrofit experience is not limited to the United States. Further, the frame of reference for retrofit experience is not limited to HGA. Therefore, retrofit of units in HGA is not necessary to demonstrate the technical feasibility of the ESADs. SCR has been successfully demonstrated to achieve a 90% reduction of $NO_x$ from combustion flue gas streams. 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 a variety of factors will affect the practice of SCR retrofits in HGA. Retrofits can be expected to be more difficult 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%. For gas turbines, 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%. Therefore, the average SCR reduction requirement for gas-fired boilers, process heaters, and gas turbines will need to be significantly less than 90%.

Deason testified that in some cases it may not be possible to retrofit a unit with SCR and, if combustion controls do not achieve the ESAD, the options are to overcontrol elsewhere, reduce the firing rate, or shut the unit down.

Application of retrofit control technology on existing equipment, replacement or consolidation of existing equipment, and shutdown of existing equipment are possible options for reducing $NO_x$. Another option is for an owner to manage activity levels of equipment and place higher levels of control on high utilization units and less controls on less utilized units. The commission carefully weighed and analyzed the technical feasibility of the potential control options in determining the level of the existing 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's comment on the Chapter 117 revisions which were proposed in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) 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 elsewhere in this preamble and in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register* (26 TexReg 524).

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 facilities' 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.

Deason testified that best available control technology (BACT) reflects the best technology available to achieve the lowest limit possible considering both technical feasibility and economic feasibility. Deason further testified that ExxonMobil recently obtained a permit for a new F20 pyrolysis reactor in HGA, and BACT was set at 0.06 lb/MMBtu, while the ESAD is 0.010 lb/MMBtu. McAngus testified that BACT is only used in permits and not rules. Hamilton testified that part of the rule development for the existing ESADs included a review of BACT in SCAQMD, and that the SCAQMD website includes examples of new refinery heaters units that had been permitted at lower levels than the existing ESADs. Hamilton testified that SCAQMD's BACT standards were based on the demonstration that the level of control represented by their BACT could be achieved in practice.

The commission agrees with Deason that by definition in 30 TAC §116.10(3), BACT gives consideration "to the technical practicability and the economic reasonableness of reducing or eliminating emissions from the facility. Under 30 TAC §116.111(a)(2)(C), concerning General Application, BACT applies statewide to anyone who proposes a new facility or modifies an existing facility that will or might emit contaminants to the air in Texas. The commission also agrees that BACT is only used in new source review (NSR) preconstruction authorization under Chapter 116, Subchapter B, New Source Review Permits, and not Chapter 117. BACT determinations are made on a case-by-case basis.

In addition, permit review for major source construction and major source modification in nonattainment areas requires controls that represent the lowest achievable emission rate (LAER). LAER is defined in 30 TAC §116.12, concerning Nonattainment Review Definitions, to include "(A) the most stringent emission limitation which is contained in the rules and regulations of any approved SIP for a specific class or category of facility, unless the owner or operator of the proposed facility demonstrates that such limitations are not achievable; or (B) the most stringent emission limitation which is achieved in practice by a specific class or category of facilities, whichever is more stringent," and therefore is generally expected to be more stringent than BACT. There is no allowance for economic analysis in the definition of LAER, and therefore, cost cannot be the basis for determining that any emission limitation is unattainable in a LAER determination. In addition, LAER supersedes BACT review for those facilities or pollutants where these requirements overlap.

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 existing 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 a result, the existing ESADs are technically feasible, albeit stringent, standards which represent maximal point source $NO_x$ controls necessary for HGA to attain the ozone NAAQS. Because the goals of the various requirements are different, as described in this response to the comments, there is no question that in some cases the ESADs are more stringent than BACT or even LAER. For example, the existing 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.

*MODELING*

ED commented that this SIP revision and future SIP revisions should not weaken the December 2000 HGA SIP, and that if at any time the commission proposes to remove or modify a strategy in the December 2000 SIP, then it should simultaneously provide a replacement strategy that achieves an equivalent reduction in ozone levels. ED stated that the demonstration of equivalence should be quantitative and based on photochemical modeling. ED further questioned the validity of the qualitative argument presented by the commission about the offsetting benefits of grandfathered pipeline facilities to be adequate, and was particularly concerned that the substituting emission reductions from pipeline facilities will not occur inside the eight-county HGA nonattainment area.

The modeling staff plans to conduct quantitative photochemical modeling early next year of an August/September 2000 episode. This modeling will evaluate the effectiveness of the new requirements for the grandfathered pipeline facilities and determine what, if any, shortfall exists at that time. If additional measures are required to demonstrate attainment, then the commission will include them in a future SIP revision not later than the 2004 mid-course review.

GHASP commented that the SIP language and the form of the plan to consider the ozone issue and the review of the 90% reduction in industrial point emissions next year is unwarranted and will leave the plan even further behind.

The mid-course review process includes an examination of new information, technology, and science. A thorough evaluation of all modeling, inventory data, and other tools and assumptions used to develop the attainment demonstration has already begun. It will also include the ongoing assessment of new technologies and innovative ideas to incorporate into the plan. For example, if the science supports its development, the commission is committed to developing an enforceable plan to minimize releases of reactive hydrocarbon emissions and the emissions of chlorine. To the extent that the science confirms the benefit from this program, it is the intent of the commission to implement such a program through a SIP revision which will first offset $NO_x$ reductions from industrial sources. Any revisions to the SIP must ensure that attainment demonstration can be reached.

BCCA and BCCAAG commented that an analysis of ozone monitored data from 1990 to 1998 shows different types of ozone patterns in Houston, with some ozone exceedances reflecting daily gradual increases and decreases in observed ozone values ("typical ozone"). BCCA and BCCAAG stated that other ozone exceedances, however, result from the rapid formation of ozone that exceeds 40 ppb per hour ("spike ozone"). BCCA and BCAAAG stated that spike ozone, which is often responsible for ozone exceedances, has been observed at many monitoring points and under all types of meteorology, and that the 90% reduction in $NO_x$ emissions from point sources (adopted by the commission on December 6, 2000) will not control spike ozone or bring the HGA into attainment. BCCA and BCCAAG stated that spike ozone requires a minimal amount of $NO_x$ and emissions of very reactive compounds. For this reason, BCCA and BCCAAG advocated a two-part attainment strategy, to address two separate causes of ozone exceedances. As the first part of this strategy, BCCA and BCCAAG suggested that the commission use its current photochemical model to design control strategies for exceedances resulting from typical ozone. BCCA and BCCAAG further stated that the commission should then address exceedances resulting from spike ozone by proposing "best management practices" for controlling reactive VOC emissions; completing a scientific assessment and evaluation of key chemical compounds and/or other causes of spike ozone; and adopting rules for controlling reactive VOC emissions.

As part of a court ordered Consent Decree, the commission's technical analysis staff will provide management with written findings on the following by February 28, 2002: analysis of rapid ozone formation events versus "normal" events; whether these events can be controlled with different strategies; any alternative design value based on "normal" ozone; and any alternate $NO_x$ reductions from point sources, concurrent with substituted emission reduction strategies designed to reduce rapid ozone formation.

Unfortunately, it is difficult to routinely observe the rate at which ozone is formed but instead one can only observe the rate of change in ozone concentration seen at monitoring sites. These two quantities are of course related, but there are important distinctions between them. Furthermore, there are several competing terminologies which are often used interchangeably to describe the various phenomena associated with rapid ozone formation. The agency is attempting to work with scientific experts to propose definitions which help to standardize the discussions of rapid ozone formations and clarify the distinctions between it and ozone "spikes."

A series of accelerated science and technical projects carried out by contract to evaluate the data from the Texas 2000 Air Quality Study (TexAQS), with improved inventories and other information, will provide the commission with the best science to date for making decisions for SIP revisions. In order to propose replacement of the current $NO_x$ ESADs, the commission must reach a sufficient understanding of the cause and effect of ozone formation events and must identify control strategies which are technically sound, sufficiently quantifiable, and readily implementable. Future control strategies may include best management procedures for control of VOC emissions.

ED commented that it is pleased that the commission plans to undertake a scientific evaluation of ozone "spikes" in HGA. ED expressed the belief that reducing emissions of reactive hydrocarbons during upsets and other non-routine emissions events would be an important component of an effective attainment plan for HGA. GHASP applauded the commission for determining that "stakeholders have expressed their belief that the {"ozone spike"} phenomenon is caused by episodic releases of highly reactive VOCs." GHASP stated that some believe that major industrial sources are occasionally releasing major amounts of toxic chemicals into the air (upsets), triggering dramatic increases in ozone smog as well as creating an immediate and direct health risk to the public. GHASP further stated that the relationship between upsets and ozone episodes has been widely known for years, and that the time for the commission to study and propose regulations to address these releases is long overdue. Houston commented that it supports the commission's efforts to determine the impacts of industrial upsets, chlorine, routine non-uniform emissions and the potentially highly reactive nature of $NO_x$ and VOC from point sources in the region so that appropriate policies may be implemented within the next two to three years before the 2004 mid-course review.

The commission's scientific evaluation of ozone "spikes" will seek to address all possible causes of these events to include reactive hydrocarbons during upsets and other non-routine emissions events. Several activities are underway: to further characterize day-to-day levels of VOC emissions in the ship channel area; to compare monitored VOC levels with reported emissions inventories; and to study point source flares and "upsets." These additional data gathering activities should provide better answers for addressing ozone smog in HGA. The Technical Analysis Division staff is on an accelerated timetable to gather as much scientific knowledge on impacts of industrial upsets, chlorine, routine non-uniform emissions, and highly reactive VOC. The commission is using stakeholders from the Houston area as well as national contractors to work on specific projects so that the best science can be used to implement new policies and/or strategies.

*ESAD - UTILITY BOILERS*

Reliant supported the revised ESADs for utility boilers in §117.106(c), while Dynegy stated that the revised ESADs in §117.106(c)(1) create an inequity between utility and non-utility boilers. GHASP stated that the commission should clarify that the existing ESADs for utility boilers could be reinstated in 2004 if the commission cannot adopt other regulatory measures to attain the ozone NAAQS in 2007. ED and Sierra-Houston opposed the relaxation of the existing ESADs. ED stated that the commission should apply the reductions from grandfathered pipeline facilities on top of, not instead of, the difference between reductions from the existing and revised utility boiler ESADs. Sierra-Houston stated that the commission should be strengthening standards and not weakening them.

The existing ESADs for both utility and non-utility boilers are technically feasible, as discussed in detail in the ANALYSIS OF TESTIMONY section of the preamble to the Chapter 117 rulemaking which was published in the January 12, 2001 issue of the *Texas Register*. The revised ESADs for utility boilers in §117.106(c) were developed by BCCAAG as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described earlier in this preamble. The Consent Order specifically provides that the "Executive Director may propose . . . the Alternate ESAD Selection Rule, which shall consist of either (1) a rule confirming the . . . 80% Option, or (2) a rule establishing revised ESAD requirements for covered point sources that are different than either the 80% Option" or the ESADs in §117.106(c)(5) and §117.206(c)(1) - (17). Until the scientific assessment is completed in the spring of 2002, it cannot be known if the alternate ESADs will even be implemented and, if implemented, what level of alternate ESADs will be supported by the assessment. If these or other ESADs, or other additional rulemakings, are proposed, the commission will support that proposal with a fiscal analysis and modeling to support any changes to the HGA SIP and the rules in Chapter 117, all of which will be subject to public notice and comment. It should be noted that Dynegy is one of BCCAAG's member companies and presumably had input into BCCAAG's development of the revised ESADs. While there is an inherent inequity in the establishment of a less stringent ESAD for utility boilers at this time, the existing utility boiler ESADs could be reinstated in the future if the commission determines that it is necessary for HGA to attain the ozone NAAQS.

The point source $NO_x$ control strategy as adopted on December 6, 2000 had an associated $NO_x$ emission reduction of 595 tpd. While the revisions to the point source $NO_x$ rules are now expected to reduce $NO_x$ by 586 tpd, the effect of this increase is counterbalanced by reductions enacted by the Texas Legislature requiring the permitting of grandfathered facilities in east and central Texas. The legislature requires certain grandfathered sources in this region to reduce emissions of $NO_x$ by approximately 50%. The commission believes that the current rulemaking will provide similar air quality benefits to the December 6, 2000 SIP revision for several reasons. First, $NO_x$ emissions in east and central Texas will be significantly lower overall under the current SIP than under the December 6, 2000 SIP revision. Second, ozone production efficiency at the sources affected by the recent legislation is expected to be very high, based on recently published results from an ozone study conducted in the Nashville, Tennessee area by the Southern Oxidant Study. Results from the Texas 2000 Air Quality Study indicate that ozone production at Reliant's W. A. Parish power plant is three to five times lower than what is expected from the rural grandfathered sources. No data is currently available on ozone production efficiency at other Reliant units, but it is expected to be somewhat higher than that at the Parish facility. Third, the increased $NO_x$ emissions will occur at peaking units, which generate most of their emissions in the afternoon, at least during the ozone season. Modeling has shown that afternoon emissions are less important in ozone formation than are morning emissions.

The commission commits to adopt measures necessary to achieve at least 56 tpd of $NO_x$ emission reductions in the HGA area above and beyond those reductions already identified by the control measures listed in Chapter 6, Table 6.1-2 of the SIP. Additionally, as the commission completes the mid-course review process, as outlined in Section 7.2 of the SIP, it may show that the HGA area needs more or fewer tpd of $NO_x$ emission reductions for attainment by November 15, 2007. Should the scientific assessment and mid-course review show that more or fewer reductions are necessary, the commission will submit the revised reduction calculation to EPA for approval. The SIP revision submitted in May 2004 will account for those additional reductions above and beyond the 56 tpd commitment if the mid-course review shows they are necessary for attainment.

In any case, the revised ESAD is cost-effective in terms of cost per ton of $NO_x$ compared to the ESADs in the December 6, 2000 SIP revision, and results in a very large reduction in emissions. Detailed modeling will be required to quantitatively assess the overall effect of these two compensating changes to the emissions inventory. The commission will address this issue during the first phase of the mid-course review.

EPA commented that the commission should document for the record that relaxing controls for utility boilers from 93.5% to 90% still represents reasonably available control measures (RACM) for these sources. EPA also commented that if the commission develops additional proposed rulemaking and an additional revision to the SIP to implement alternative $NO_x$ ESADs for point sources, the commission will have to demonstrate, as part of that SIP revision, that the new level of control is still RACM for point sources. Finally, EPA commented that the commission should document that a RACM level of control is being instituted for glass manufacturing plants since the one significant source in the inventory has now been issued a permit requiring oxygen firing.

The commission agrees with the comments regarding RACM for utility boilers and for glass manufacturing plants. Language has been added to Section 7.3 of the SIP to address these comments. Regarding any additional future rulemaking, the commission will take this comment into account if such a rulemaking does occur.

McAngus testified concerning four California utility boilers owned by Reliant. McAngus acknowledged that these units are meeting the ESADs, but suggested that inherent differences between these units and the utility boilers in HGA will make the ESAD technically infeasible to achieve. McAngus stated that a fundamental difference is that the Reliant California units are capable of firing fuel oil and natural gas while the HGA units were originally designed to fire exclusively natural gas. McAngus stated that gas-fired boilers tend to be more compact than boilers designed to burn fuel oil, and therefore are more limited in possible retrofits. Hamilton testified that the existing gas utility boiler ESADs are approximately equal to the VCAPCD retrofit standards.

The commission disagrees with McAngus's claim 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, Regional Clean Air Incentives Market (RECLAIM), for which the underlying emission specification is the 1991 SCAQMD Rule 1135 emission standard of 0.15 pound $NO_x$ per megawatt-hour (lb $NO_x$/MWh). This output standard is approximately equal to a heat input standard of 0.015 lb/MMBtu. In Reliant's comments on the Chapter 117 revisions which were proposed in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275), Reliant stated that only four of 13 boilers they identified in Southern California are below the ESAD and that the average emission rate of the 13 boilers is 0.015 lb $NO_x$/MMBtu. Four of the 13 boilers Reliant identified, Ormond Beach 1 and 2, and Mandalay 1 and 2, are the only utility power boilers subject to the VCAPCD retrofit 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 Reliant. The data Reliant supplied in their previous comments indicate that the MW weighted average emission rate for these four boilers is 0.0085 lb/MMBtu, which is comfortably below the existing ESAD. Three of these boilers are among the four which operate below the existing 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 existing 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 Reliant 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 Reliant boilers would produce somewhat higher levels of $NO_x$. This would not mean that achieving the ESAD is technically infeasible, although the smaller furnace volumes would have some relevance in the cost. 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 Collin County, 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 *Status Report on $NO_x$ Control Technologies and Cost Effectiveness for Utility Boilers* (June 1998), prepared for Northeast States for Coordinated Air Use Management and Mid-Atlantic Regional Air Management Association (will be referred to as NESCAUM) 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. With all of the combustion technology currently available, gas-fired utility boilers can be modified to achieve quite a bit less than 0.10 lb/MMBtu. A 90% reduction with SCR from 0.10 lb/MMBtu will achieve the existing ESAD of 0.010 lb/MMBtu. Therefore, the combination of combustion control and SCR is technically capable of achieving the existing gas utility boiler ESAD.

McAngus stated that certain types of low-$NO_x$ burners can not be used because the flame will sometimes impinge on the tubes, resulting in hot spots which will cause the tubes to fail prematurely.

McAngus did not specify exactly which types of low-$NO_x$ burners to which he referred. Even if McAngus's claims were accurate, his testimony indicates his opinion is that the alleged problem occurs only with certain types of burners, such that other low-$NO_x$ burners are available for which flame impingement is not an issue.

Burner manufacturers design burners for specific combustion properties, including flame shape. In each case, application engineers are responsible to select the best burner for the chamber and process. Selecting a burner that will provide a flame geometry that is suitable for the application is a vitally important part of engineering a thermal system. As units are refitted with new low-$NO_x$ combustion hardware, the flame geometry will be different from conventional burners. However, one of the tasks of combustion equipment vendors is assisting the end user in selecting hardware that is compatible with the geometry and heat requirements of the unit.

A low-$NO_x$ burner manufacturer's experience is that if no change is made to the fuel being fired during a burner retrofit, then a low-$NO_x$ burner can be engineered to conform with the physical constraints of the unit. Some geometries are particularly challenging and the burner configuration may need to be modified in ways that will increase the $NO_x$ emissions in the low-$NO_x$ burner, above the low $NO_x$ emissions that would be developed by that same burner under the same firing conditions, in a "friendlier" chamber.

However, control options other than low-$NO_x$ burners are also available, and combustion controls continue to develop dynamically, achieving teen and even single digit $NO_x$ ppm in a growing number of applications. Burner replacement is but one of many combustion control options. 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 Collin County, Texas, this is currently achieving 0.04 lb/MMBtu, with expectations of even better performance.

*ESAD - FCCU*

Deason testified that no FCCU with an SCR retrofit has achieved the ESAD. Hamilton testified that the 90% reduction of the FCCU ESAD is based upon the ExxonMobil FCCU in Torrance, California. Hamilton testified further that if this FCCU was in fact a new unit rather than a retrofit, it would be useful as an example of a unit that is "actually in operation achieving levels lower than the adopted emission standard," and therefore, still would be significant. Hamilton testified that the difference between retrofits and new units is "significant in terms of cost, but not in terms of technical feasibility."

The commission agrees with Hamilton and notes that 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. On August 14, 2001, a SCAQMD representative stated that SCAQMD hasn't had any new FCCU installations with SCRs and that the ExxonMobil Torrance refinery FCCU was definitely an SCR retrofit to an existing FCCU.

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 option in the existing FCCU ESAD of either a concentration limit or a percent reduction ensures that this standard is technically feasible.

*ESAD - BIF UNITS*

TCC stated that the ESAD for BIF units may be unachievable for BIF units that burn wastes containing fuel-bound nitrogen.

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. 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, 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 existing ESADs for BIF units in §117.206(c)(3) were developed from this information and therefore reflect the effects of fuel-bound nitrogen. $NO_x$ produced by fuel-bound nitrogen is not any different from $NO_x$ formed by the other formation mechanisms, "thermal" or "prompt" $NO_x$. Because of this, the presence of fuel-bound nitrogen does not pose questions of technical feasibility that have not already been considered.

TCC also stated that many wastes burned in BIF units contain components that cause catalyst fouling and poisoning, resulting in poor performance and higher operating costs, and may counter other technologies driving organic and/or dioxin destruction and metal removal. TCC suggested that the ESAD be relaxed to a level representing non-SCR technology.

The existing ESAD for BIF units in §117.206(c)(3) is not based upon combustion modifications due to the potential for affecting the hydrocarbon destruction and removal efficiencies, but instead is based upon Tier 2 control. Because 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. Therefore, the existing ESAD in §117.206(c)(3)(A) for BIFs rated 100 MMBtu/hr heat input or greater is based on SCR at 90% control because these boilers combust hydrocarbon wastes which do not threaten to reduce the effectiveness of SCR as the flue gas cleanup application.

For smaller BIFs, the existing ESAD in §117.206(c)(3)(B) is based on 80% control, rather than 90%, to take into account the concerns raised 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 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.

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 second 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 existing ESAD for the BIFs rated less than 100 MMBtu/hr heat input is either an 80% reduction from baseline, or 0.030 lb/MMBtu.

*ESAD - WOOD-FIRED BOILERS*

Abitibi commented on the $NO_x$ emission specification of 0.046 lb/MMBtu for wood-fired boilers in §117.206(c)(5) and the proposed §117.206(c)(18)(E). Abitibi stated that one of its boilers, which the commission has classified as a wood-fired boiler, is a "combination-fuel boiler" which fires a variety of fuels, including wood, tire-derived fuel (TDF), and dewatered wastewater treatment sludge. Abitibi stated that the higher percentage of nitrogen-containing compounds in sludge as compared to wood can be expected to increase $NO_x$ emissions in boilers using wood in combination with other fuels, as compared to wood-fired boilers. Abitibi also stated that TDF is necessary to provide the necessary heat input to offset the relatively high moisture content of the sludge.

As noted earlier in this preamble, chemically-bound nitrogen, also called fuel-bound nitrogen, is one of the three common production routes for $NO_x$ emissions, the others being thermal $NO_x$ and prompt $NO_x$. Emissions from fuel-bound nitrogen and emissions associated with offsetting the relatively high moisture content of the sludge were presumably reflected in the emission factors that Abitibi (or its predecessor company, Donohue Industries Incorporated (Donohue)) provided to the commission in the emission rate survey conducted in the first quarter of 2000. The existing ESAD for wood-fired boilers in §117.206(c)(5) was developed from this information and therefore reflect the effects of fuel-bound nitrogen and the moisture content of the sludge. $NO_x$ produced by fuel-bound nitrogen is not any different from $NO_x$ formed by the other formation mechanisms, "thermal" or "prompt" $NO_x$. Because of this, the presence of fuel-bound nitrogen does not pose questions of technical feasibility that have not already been considered. Similarly, $NO_x$ resulting from additional heat input due to the moisture content of the sludge is no different than other $NO_x$ and does not pose questions of technical feasibility that have not already been considered.

Abitibi stated that there are significant technical issues associated with the use of SCR on boilers using wood in combination with other fuels, and that it may take several years for proven technologies to be available that can achieve an 80% $NO_x$ reduction. Abitibi stated further that the use of SNCR on combination-fuel boilers can only achieve a 55% $NO_x$ reduction, and requested that the commission establish an SNCR-based ESAD for either combination-fuel boilers or for all wood-fired boilers. Abitibi stated that the current ESAD in §117.206(c)(5) should be revised, and that at the very least the alternate ESAD of §117.206(c)(18)(E) should be revised.

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 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 reported with the operation of Bowater's SNCR system since it was installed. The commission is aware of at least 16 other commercial applications of urea-based SNCR on wood- or wood/biomass-fired systems on boilers ranging in size from 130 to 550 MMBtu/hr, representing $NO_x$ reductions of 35% - 60% (average of 51%). In some cases, the data for these individual units represent the guaranteed reduction percentages or the permitted limits, both of which are set to provide a "cushion" such that the actual emission reductions are greater than the targeted emission reductions. In other words, lower efficiencies may simply reflect the regulatory limit rather than the capability of the technology in the particular application.

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 57 MMBtu/hr 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 second 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 a more representative design goal for dirty fuel streams. The oxidation technologies appear capable of the 90% reductions envisioned by the ESAD proposed in August 2000. 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 it would appear equitable to revise the alternate ESAD for wood-fired boilers in §117.206(c)(18)(E) in the event that the alternate ESADs are implemented, the commission has modified the alternate ESAD for wood-fired boilers to 0.060 lb/MMBtu. This represents SNCR achieving a 60% $NO_x$ reduction. If implemented, this alternate ESAD would result in 0.07 tpd fewer emission reductions than the current ESAD.

*ESAD - OIL-FIRED OR LIQUID-FIRED BOILERS*

No changes were proposed to the ESAD for oil-fired boilers in §117.206(c)(7). However, the commission clarifies its intent that this ESAD applies not just to boilers firing oil, but to boilers firing any liquid fuel which does not cause the unit to fall under the BIF unit ESAD. The commission anticipates initiating rulemaking after October 15, 2001 to revise §117.206(c)(7) accordingly, along with a variety of other minor clarifications that were not included in the current rulemaking.

*ESAD - ICI BOILERS AND PROCESS HEATERS*

Deason testified that no process heater with an SCR retrofit has achieved the ESAD. Deason testified that all retrofits that ExxonMobil identified, whether in Louisiana, California, or Germany, are "performing at levels well in excess of" the ESADs. Hamilton testified that the 0.036 lb/MMBtu ESAD for process heaters and furnaces less than 40 MMBtu/hr in size is less stringent than the 0.030 lb/MMBtu retrofit standard set by numerous districts in California for that type of equipment.

The commission disagrees with Deason. 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 in size. Most districts in California set boiler and process heater retrofit requirements at this level for ICI boilers and process heaters above five MMBtu/hr, whereas SCAQMD and VCAPCD set the applicability levels at two 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 existing HGA ESADs is a function of regulatory standards, rather than technical feasibility. Regulations set emission levels, and the HGA $NO_x$ ESADs 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.

McAngus testified that regarding the nine California process heaters cited by the commission as meeting the ESADs (three at Chevron (El Cerrito) and six at Mobil (Torrance)), "we contacted each of these facilities and talked to them...." and "all three of {the Chevron} furnaces were new facilities that had been built in the early '90s" and "the SCRs had been designed into the original design of this process, so it was not a retrofit condition." McAngus further testified that "in the situation for Mobil, there were six furnaces," and "five of the six" were new facilities. "In the case of the retrofit, it had an ammonia slip limit of about 20 ppm, which is twice the" Chapter 117 limit of ten ppm. McAngus suggested that information from SCAQMD in response to a November 27, 2000 email, which provided the basis for the reference, was not accurate because the units referenced that are meeting the ESADs are new, not retrofits, and therefore the ability "to retrofit down to these levels {i.e., the ESADs} has not been demonstrated." Hamilton testified that if these process heaters were in fact new units rather than retrofits, they would be useful as examples of units that are "actually in operation achieving levels lower than the adopted emission standard," and therefore, still would be significant. Hamilton testified that the difference between retrofits and new units is "significant in terms of cost, but not in terms of technical feasibility."

The commission disagrees with McAngus's claim that the ability to retrofit to meet the existing ESADs has not been demonstrated. McAngus's own testimony is that at least one of the six process heaters meeting the ESADs at ExxonMobil in Torrance is a retrofit. The commission agrees that retrofits can be expected to be more difficult than new installations. However, as described elsewhere in this preamble, including the response to the previous comment, as well as in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)), the existing ESADs are technically feasible. The difference between retrofits and new installations relates more to potential cost and the need for a reasonable compliance schedule to implement the retrofits than to the technical feasibility of the ESADs. As noted in the response to the previous comment, 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. On August 15, 2001, a SCAQMD representative confirmed McAngus's testimony that one of the six process heaters meeting the ESADs at the ExxonMobil refinery in Torrance is a retrofit. Specifically, the SCAQMD representative advised that heater 924 at this ExxonMobil refinery was retrofitted with an SCR unit in 1992. On August 15, 2001, the SCAQMD representative also confirmed that the three process heaters meeting the ESADs at the Chevron refinery in El Cerrito were retrofitted with a common SCR unit in 1994. The commission agrees with Hamilton that the five process heaters which were new units rather than retrofits are useful as examples of units that are in operation achieving emission levels below the existing ESAD.

Deason testified that a new ethylene plant pyrolysis reactor was built in Germany in the late 1980's and was designed with a low-temperature SCR when built. Deason testified that it was designed "to achieve a standard five times the level" of the applicable ESAD, and the SCR requires annual maintenance to clean particulate off the catalyst.

Ethylene furnaces present a challenge to control, particularly with regard to Tier I controls, due to a variety of factors. 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 existing 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.

Regarding the German ethylene furnace that Deason referenced, Deason did not indicate what emission specification this unit was designed to achieve. If the unit was specifically designed to meet a less stringent requirement, it would not be logical to expect that the unit would necessarily meet a more stringent ESAD. Depending on the regulations in effect and the compliance strategy used by the owner, lower control 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.

Deason also did not provide details about the reported annual maintenance on the German unit's SCR. It is possible that coke formed during the pyrolysis reaction in an ethylene furnace could degrade the low-temperature SCR catalyst performance more rapidly than other applications, thereby shortening the life of the catalyst and/or resulting in periodic maintenance to clean particulate off the catalyst. Although these maintenance activities would result in higher operating costs relative to a more conventional SCR application, SCR is still technically feasible.

*ESAD - IC ENGINES*

GHASP supported the new ESADs for diesel engines. ED stated that future emissions from stationary diesel engines used for electrical generation in HGA could be significant and undermine the SIP. ED suggested that the same requirements as the Air Quality Standard Permit for Electric Generating Units, effective June 1, 2001, should be established for new and existing stationary diesel engines in HGA that are not used exclusively for emergency situations.

Amendments to Chapter 106, Permits by Rule, Subchapter W, Turbines and Engines, effective June 1, 2001, preclude registration under §106.512 of new or modified engines or turbines used to generate electricity. However, exempted from this preclusion are: 1) engines or turbines used to provide power for the operation of facilities registered under the Air Quality Standard Permit for Concrete Batch Plants; 2) engines or turbines satisfying the conditions for facilities permitted by rule under Chapter 106, Subchapter E, Aggregate and Pavement; and 3) engines or turbines used exclusively to provide power to electric pumps used for irrigating crops. While it is possible that an owner or operator of a new or modified engine or turbine used to generate electricity could pursue preconstruction authorization under Chapter 116, Subchapter B, New Source Review Permits, the commission expects that most, if not all, such owners or operators would pursue authorization under the Air Quality Standard Permit for Electric Generating Units, effective June 1, 2001, in order to expedite the permit authorization process and minimize costs associated with public notice. In addition, the commission expects that the BACT review resulting from an owner or operator seeking preconstruction authorization under Chapter 116, Subchapter B, New Source Review Permits, for a new or modified engine or turbine used to generate electricity would result in the same level of control as the standard permit. Further, an existing 100 hp engine emitting $NO_x$ at an uncontrolled rate of 11.0 g/hp-hr would have a design capacity to emit greater than ten tpy of $NO_x$, and consequently would be subject to the Chapter 101 mass emissions cap and trade program. It should be noted that a new engine which operates 100 hours per year or more in nonemergency situations would not receive allocations and would have to obtain credits in order to operate, thereby protecting against an increase in emissions in HGA and maintaining the integrity of the SIP.

Based upon information in the commission's emissions inventory and contact with diesel engine vendors and others familiar with the stationary diesel engines in HGA, the commission is unaware of any existing stationary diesel engines that are being operated in situations other than generation of electricity in emergency situations or operation for maintenance and testing. Since any such existing engines at a site with a collective design capacity to emit (from units with ESADs) equal to or greater than ten tpy of $NO_x$ are subject to the Chapter 101 mass emissions cap and trade program if they operate 100 hours per year or more (based on a rolling 12-month average) and will be issued allocations based on their historical activity level, the commission does not believe that these engines currently merit additional emission limitations beyond those in this rulemaking. It is possible that existing emergency diesel generators could be converted to peak shaving use, thereby contributing to ozone exceedances due to operation on days which tend to have favorable conditions for high ozone levels. However, emergency diesel generators typically are on a timer which operates them for 30 minutes to one hour per week for maintenance and testing. Since the 100 hours per year limit includes the time of operation for maintenance and testing, this would leave approximately 48 to 74 hours per year available for peak shaving operation. This is expected to be too few hours of peak shaving to justify the expense of the interconnect switching equipment necessary to supply power to the grid. The commission believes that these factors will effectively discourage the conversion of existing emergency generators to peak shaving units while still reducing emissions in a cost-effective manner when the engines are replaced, modified, reconstructed, or relocated. Therefore, the commission made no change in response to the comments.

*ESAD - GAS TURBINES*

Deason testified that no gas turbine or duct burner, whether new or retrofit, has achieved the ESAD of 0.015 lb $NO_x$ per MMBtu, based on "an extensive survey" conducted by industry representatives in 2000.

The existing 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 existing 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 existing 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 existing gas 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 existing 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. This gas turbine includes a duct burner rated at 200 MMBtu/hr and 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.

Regarding duct burners, a gas turbine equipped with a duct burner is not expected to be more difficult to retrofit with controls than a gas turbine without a duct burner. Gas turbines with and without duct burners have effectively been placed in the same category for purposes of the ESADs based on data collected by the Air Permits Division as part of a March 2000 review of BACT for gas turbines. It should be noted that it would be more cost-effective to control a gas turbine/duct burner combination because the additional $NO_x$ from the duct burner could be controlled with the same SCR unit, such that there would be no additional capital expense for a separate SCR.

*ESAD - INCINERATORS*

Safety-Kleen commented on the existing and proposed alternate ESADs for incinerators in §117.206(c)(16) and (18), which establish an ESAD of 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. Safety-Kleen noted that for the 80% option, new language specifies that a consistent methodology must be used to calculate the 80% reduction.

The new language is necessary to prevent an owner or operator from using an emission factor which overestimates the June - August 1997 daily $NO_x$ emissions, using an emission factor which more accurately estimates the $NO_x$ emissions, and then claiming credit for the resultant "paper" emission reductions without actually achieving the real emission reductions that the rule is intended to achieve.

Safety-Kleen stated that according to its emission calculations and documentation in its recently submitted level of activity certification, the expected reduction in actual emissions for its two commercial hazardous waste incinerators will be greater than 91%, because Safety-Kleen's level of activity for the June - August 1997 time period was "unusually low" and may vary significantly as a result of processing a wide variety of waste streams. Safety-Kleen noted that proposed changes to §117.108(c)(1) will revise the system cap for EGFs by allowing the owner or operator to choose any consecutive 30-day period within the third quarter, rather than the system highest 30-day period, and suggested that incinerators be given similar flexibility in selecting a three-month period from a three-year window in order to determine emission limits. Safety-Kleen stated that otherwise, it might have to purchase emission credits on an annual basis, even with SCR installed.

The optional 80% ESAD for incinerators is based on the emission factor used to calculate the June - August 1997 daily $NO_x$

emissions, and not the activity level. Electric utilities in HGA are required to comply with a system cap on the basis of daily and 30-day averaging periods under §117.108 in addition to complying with the Chapter 101 mass emissions cap and trade program. Incinerators are not comparable to electric utilities in that there are no corresponding daily and 30-day emission limits for incinerators in Chapter 117. The rules include an ESAD of an 80% reduction from the emission factor used to calculate the June - August 1997 daily $NO_x$ emissions, but this is an option in lieu of an ESAD of 0.030 lb $NO_x$ per MMBtu. For both incinerators and electric utilities, the Chapter 101 mass emissions cap and trade program establishes annual $NO_x$ emission allowances based on the level of activity, generally averaged over a three-year period (1997 - 1999), and the Chapter 117 ESAD. For purposes of the system cap, electric utilities are given a broader time period (any 30-day period in the nine months of July, August, and September 1997, 1998, and 1999) for determining which time period represents the maximum heat input rate because electric utilities, unlike other sources, have no control over their level of operations.

*AMMONIA AND CO EMISSIONS*

BP suggested the elimination of §117.206(e)(2), which limits ammonia emissions to ten ppmv, with ammonia limits established instead through BACT review under NSR permitting for sources installing SCR.

No changes were proposed to §117.206(e)(2). However, it is desirable to minimize ammonia emissions because ammonia emissions create fine particulate matter, another form of air pollution. The existing ammonia limit of ten ppmv 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 *Status Report on $NO_x$ Control Technologies and Cost Effectiveness for Utility Boilers* (June 1998), prepared for NESCAUM. The utility boiler operators cooperated in the development of this report by providing actual project cost, operating cost, as well as operating experience.

The commission does not expect most SCR projects to undergo BACT review because the Standard Permit for Pollution Control Projects in 30 TAC §116.617 should be available for use by SCR projects with a 30-day review time period. 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 much of the permitting time associated with a BACT review, provided that the ammonia emissions from the storage, handling, and slip do not create any health concerns.

It should be noted that §117.114(b) and §117.214(b)(1) require testing as specified in §117.111 and §117.211, respectively, which in turn require testing under §117.111(b) and §117.211(a)(2), respectively, for ammonia emissions on units which inject urea or ammonia into the exhaust stream for $NO_x$ control. Similarly, §117.479(e)(2) requires testing for ammonia emissions on units which inject urea or ammonia into the exhaust stream for $NO_x$ control. This testing is necessary to ensure compliance with the ten ppmv limit on ammonia emissions.

McAngus testified that he "estimated or calculated that there will be an additional 35.58 tpd of ammonia emitted into the atmosphere" in HGA due to ammonia slip. McAngus expressed the opinion that with an assumption of ten ppmv ammonia slip, companies are "going to have to push their SCRs as high as possible" in "an attempt to drive down the $NO_x$ emissions." Hamilton testified that ammonia slip is a very manageable issue and that "through the engineering design and consideration of mixing conditions, the ammonia slip can be minimized up front." Hamilton testified that ammonia slip can be further addressed during the start-up period, and commented that he is aware of "two catalyst vendors that market a catalyst which is a slip reduction catalyst." Hamilton testified further that other vendors are "working on new variants of their catalysts, which would be a 'no slip' catalyst, so there are products available today, and also other products being worked on to improve the performance" concerning ammonia slip. Hamilton testified that an individual at Southern California Edison, who had provided some of the cost estimates for one of the documents the commission relied upon for the cost estimates, indicated that annual testing for ammonia in the company's gas-fired utility boiler stacks typically results in ammonia slip below detectable levels. Hamilton testified that the document (NESCAUM's *Status Report on $NO_x$ Control Technologies and Cost Effectiveness for Utility Boilers* (June 1998)) includes ammonia slip levels from utility boilers (in Table 2-5), and all were under ten ppmv.

McAngus's estimate of 35.58 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 cost note sections of the preamble to the Chapter 117 revisions which were proposed in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275). 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, McAngus's estimate of 35.58 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 five ppmv (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 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.

*DEFINITIONS*

It has come to the commission's attention that the definition of "boiler" in §117.10(6) inadvertently does not include large water heaters rated at greater than 2.0 MMBtu/hr because the definition refers to producing steam. These units may be as large as approximately 5.0 MMBtu/hr and are no different to control as the corresponding-sized boiler. The commission anticipates initiating rulemaking after October 15, 2001 to revise the definition of "boiler" in §117.10(6) accordingly by adding a reference to heating of water. In addition, the commission revised the lead-in paragraph to §117.10 by adding a sentence which notes that additional definitions for terms used in Chapter 117 are found in §101.1 and §3.2, concerning Definitions. This reference is intended as a courtesy to the reader who may not be familiar with the sections in which some definitions are located.

BASF commented on the definition of "electric power generating system" (EPGS) in §117.10(13). BASF stated that the definition for non-electric utility EPGSs in §117.10(13)(C) should be revised to be consistent with the definition for electric utility EPGSs in §117.10(13)(A) and (B) by stating that a non-electric utility EPGS includes only those units that generate electricity for compensation. BASF also suggested that a distinction be made between those units that generate electricity for compensation and those that receive compensation for electricity sold only during periods when industrial customers' load sources are not operated or are operating at reduced load.

The commission does not believe that the suggested change is necessary due to the revisions to §117.210(a) described later in this preamble under the heading of *SYSTEM CAPS*. However, the commission revised the definition of "electric power generating system" by adding a reference to duct burners used in turbine exhaust ducts for consistency with the new §117.101(4) and the revised §117.106(c)(3), which make the gas turbine ESAD applicable to duct burners used in turbine exhaust ducts. This change is necessary for the reasons described earlier in this preamble under the section titled SECTION BY SECTION DISCUSSION.

NASA commented on the definition of "emergency situation" in §117.10(14) and stated that it conducts operations at Ellington Field, a Federal Aviation Administration (FAA) licensed airport, and at Johnson Space Center to provide backup power to the Mission Control Center for manned space flights. NASA also stated that it employs a diesel generator to provide backup power in the event a power failure occurs during decompression treatment in the hyperbaric chamber associated with its Neutral Buoyancy Laboratory (NBL). NASA requested that these facilities be explicitly included in the definition of emergency situation.

As an FAA licensed airport, Ellington Field is one of the airports at which operation of emergency generators for the purposes of providing power in anticipation of a power failure due to severe storm activity is considered an emergency situation under §117.10(14)(A)(vi). Likewise, operation of NASA's NBL emergency generator during a power failure is considered an emergency situation under §117.10(14)(A)(i). The commission agrees that manned space flight control centers should be treated the same as FAA licensed or military airports in the definition of "emergency situation" since continual contact with astronauts during space missions is critical to their safety, and revised §117.10(14)(A)(vi) accordingly.

ExxonMobil suggested that the definition of "emergency situation" in §117.10(14) be expanded to include additional emergency situations such as storm damage, tornado damage, and safety responses that are less than life-threatening.

Tornados and severe storms can certainly be classified as life-threatening situations which, therefore, would qualify as emergency situations under §117.10(14)(A)(v). Tornado damage or storm damage represent emergency situations if they result in power failure, floods, fire, or life-threatening situations. It is unclear what type of "safety response" ExxonMobil believes would require emergency stationary firewater pumps, generators, etc., but would not be considered life-threatening. The commission believes that the definition of "emergency situation" in §117.10(14) adequately addresses the situations which are true emergencies. Therefore, the commission made no change in response to the comment.

ERM commented on the proposed definition of "pyrolysis reactor" in §117.10(40) and suggested that the definition be revised to specify that the feedstocks (for example, ethane, propane, butane, and naphtha) are not combusted. ERM stated that this would clarify that the feedstock heating value is not considered in determining the maximum rated capacity of the pyrolysis reactor.

The commission made the suggested change.

It has come to the commission's attention that the definition of "stationary gas turbine" in §117.10(44) includes a reference to major sources which is inconsistent with the change to the definition of "unit" in §117.10(50) because "unit" now refers to major and minor sources. Therefore, the commission revised the definition of "stationary gas turbine" accordingly.

*MISCELLANEOUS RULE LANGUAGE COMMENTS*

The commission made several minor changes in wording for which no comments were received. Specifically, the commission revised a variety of rules for consistency with the commission's style guidelines by replacing the wording "pursuant to" with "under" or "in accordance with," as appropriate. The rules which were revised are §§117.10(2); 117.119(e)(5); 117.213(l); 117.510(a)(1)(A)(i) and (c)(1)(A)(i) and (2)(A)(ii)(II); 117.520(c)(2)(A)(ii)(I), (C)(i), and (D)(i); and 117.534(1)(B)(i) and (C)(i), and (2)(B)(i). In addition, the commission made changes to §117.107 which spell out the abbreviation for the term "MMBtu" in §117.107(a)(3), and abbreviate the term "lb/MMBtu" in §117.107(b)(1) - (3). The commission also deleted an extra "or" in §117.570(a).

Sierra-Houston stated that the rules are difficult to read and understand.

Sierra-Houston did not identify specific concerns it had regarding the rule language. The commission made every effort to eliminate errors and improve the readability of the rule.

The EPA stated that the rule may present problems with enforceability due to the granting of discretion to the executive director in §117.113(j) and (k). Section 117.113(j) allows the executive director the discretion to establish compliance plans and schedules (within a two-year time frame) for units which lose the low annual capacity factor exemption by exceeding the threshold for exemption, and §117.113(k) allows the executive director to set methods of determining compliance. Section 117.113(k) specifies that methods required in §117.113 and §117.114 must be used to determine compliance or, at the executive director's discretion, can be determined by "any commission compliance method." The EPA commented that it is unclear whether "any commission compliance method" refers to a preexisting collection of methods or even a replicable procedure and stated that EPA guidance on "Director's Discretion in State Regulations" suggests that under some circumstances, if the director selects an alternative test method, the EPA could require written notification as to which test was applied. Alternatively, the EPA suggested that the state could simply require the owner/operator of the unit to use the test method specified for the particular type of unit set forth elsewhere in the rule, omitting the option of using other commission compliance methods. Finally, the EPA suggested that this issue could be handled in the same manner as §117.121, which specifies that "...executive director approval does not necessarily constitute satisfaction of all federal requirements nor eliminate the need for approval by the EPA...."

No changes were proposed to §117.113. However, §117.103(a)(2) and (3), which are referenced in §117.113(j), are not available as low annual capacity factor exemptions from the ESADs specified in §117.106. Instead, §117.103(a) limits the applicability of the exemptions to the provisions of §117.105, §117.107, and portions of §117.113. Therefore, the EPA's concern about §117.113(j) is unwarranted. Any possible changes to §117.113(k) to address the EPA's concern about this subsection will have to be in future rulemaking because §117.113 is not open as part of the current rulemaking.

Sierra-Houston opposed the reference to the federal new source performance standards (NSPS) definitions of "modification" and "reconstruction" in §§117.203(a)(6)(D), (11)(B), and (12)(B); 117.206(c)(9)(D); 117.473(a)(2)(E), (H)(ii), and (I)(ii); and 117.475(c)(4)(A). Sierra-Houston suggested that the 30 TAC Chapter 116 definition of "modification" be used instead.

The commission believes that the Chapter 116 definition of "modification" will be more inclusive and easier to read than the corresponding definition in 40 CFR §60.14. Therefore, the commission has replaced all references to the 40 CFR §60.14 definition of "modification" with the Chapter 116 definition of "modification" in §116.10. The commission has retained the references to the definition of "reconstruction" in 40 CFR §60.15 because there is no corresponding definition of this term in Chapter 116. In addition, the commission has clarified that the term "relocated" means to newly install at an account, as defined in §101.1, a used engine from anywhere outside that account. This is intended to prevent the importing of older, higher-emitting engines, while avoiding penalizing an owner or operator of an existing stationary diesel engine who, for whatever reason, moved the engine somewhere else at the same TNRCC air quality account. In addition, the commission has corrected the reference to §117.475(A) in §117.475(B) by replacing "clause (i) of this subparagraph" with "subparagraph (A) of this paragraph."

ExxonMobil commented on §117.206(h)(1), which prevents any derating of equipment (reducing the maximum rated capacity) after December 31, 2000 to change the applicability of the ESADs. ExxonMobil suggested that the rules should at least allow a physical derating (e.g., removing burners, or new burners with lower capacity) to be effective to change the applicability of ESADs.

ExxonMobil's suggested revision would undermine the purpose of the new §117.206(h)(1), which is to prevent an owner or operator in HGA from derating equipment to take advantage of a less stringent ESAD in §117.206(c). Allowing derating of equipment to occur on an open-ended basis would result in failure to achieve the anticipated $NO_x$ emission reductions for the HGA Attainment Demonstration SIP, thereby jeopardizing the integrity of the SIP. However, the new language allows derating from what the maximum rated capacity was on December 31, 2000, provided an administratively complete permit application (as determined by the executive director) was in-house before January 2, 2001, and the maximum rated capacity authorized by the permit issued on or after January 2, 2001 is no less than the maximum rated capacity represented in the permit application as of January 2, 2001. If the owner or operator increased the rated capacity after December 31, 2000, the higher of the two ratings would be used to determine the applicability of the ESAD in §117.206(c).

ExxonMobil stated that §117.206(h)(1) does not indicate whether a derating can affect the applicability of the monitoring requirements (i.e., CEMS) and suggested that a physical derating should be allowed to affect the applicability of the monitoring requirements.

The maximum rated capacity on December 31, 2000 would establish the applicability of the monitoring requirements for those units in §117.213(c)(1) for which a maximum rated capacity threshold applies. If, however, an administratively complete permit application (as determined by the executive director) was in-house before January 2, 2001 to derate the unit, the revised maximum rated capacity in the permit subsequently issued by the executive director in response to that application would be used to establish the applicability of the monitoring requirements for those units in §117.213(c)(1) for which a maximum rated capacity threshold applies. If the owner or operator increased a unit's rated capacity after December 31, 2000, the higher of the two ratings would be used to establish the applicability of the monitoring requirements for those units in §117.213(c)(1) for which a maximum rated capacity threshold applies. It should be noted that the owner or operator of each unit in HGA, regardless of maximum rated capacity, must install calibrate, maintain, and operate a CEMS or PEMS if the unit is equipped with controls which inject a chemical reagent for reduction of $NO_x$.

BASF stated that §117.206(h)(1)(B) should be revised to extend the January 2, 2001 cutoff for administratively complete permit applications because previous rules and/or guidance did not allow derating of equipment through permitting.

It is true that the Air Permits Division would not allow an NSR permit limit by itself to limit the heat input to a unit, thereby resulting in a different ESAD. However, the Air Permits Division does receive and process requests to derate equipment. For example, an applicant may purchase a boiler rated at 120 MMBtu/hr, but want to permit the unit at 90 MMBtu/hr for NSPS purposes. In that case, the Air Permits Division would require that an actual physical modification be made to the unit so that a simple "flip of a switch" could not be used to allow the unit to operate above the new lower capacity. In addition, the 90 MMBtu/hr limit would be included as a permit restriction (and therefore federally enforceable), not just a physical restriction. Regardless of the possibility that equipment may be derated for air permitting purposes, in order to achieve the anticipated $NO_x$ emission reductions for the HGA Attainment Demonstration SIP, it is necessary that derating of existing units not be allowed to continue indefinitely after December 31, 2000 for purposes of Chapter 117. BASF's suggestion to extend the January 2, 2001 cutoff for administratively complete permit applications would allow the derating of equipment to take advantage of a less stringent ESAD in §117.206(c), which should not be allowed for the reasons described earlier.

No comments were received on §117.206(h)(2), which establishes how units which can be classified as multiple unit types are treated for purposes of applying the ESADs. Specifically, a unit's classification is determined by the most specific classification applicable to the unit as of December 31, 2000. For example, a unit that is classified as a boiler as of December 31, 2000, but subsequently is authorized to operate as a BIF unit, shall continue to be classified as a boiler for the purposes of Chapter 117. The commission has added another example to §117.206(h)(2) which states that a unit which is classified as a stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, shall be classified as a stationary gas-fired engine for the purposes of Chapter 117. This example is broadly applicable and replaces another example which addressed a single situation in HGA. The new §117.206(h)(2) is necessary to ensure that the intended emission reductions of the program are achieved and to clarify how units which can be classified as multiple unit types are treated in Chapter 117.

No comments were received on §117.206(h)(3), which prohibits the owner or operator of units which combust fuel or waste streams containing chemical-bound nitrogen from directing these streams to flares or other units which are not subject to an ESAD. This is necessary to prevent circumvention due to the transfer of emissions associated with chemical-bound nitrogen from a unit under which these emissions would be controlled (i.e., a unit subject to an ESAD) to a unit that is not subject to the mass emissions cap and trade program (i.e., a unit without an ESAD) and therefore is uncontrolled. However, it has come to the commission's attention that this intent is not entirely clear in §117.206(h)(3), and that §117.206(h)(3)(A) and (B) should be deleted because the mass emissions cap and trade program does not currently include a provision allowing the opt-in of units to the program. Therefore, the commission revised the rule language accordingly. In addition, the commission has added new subsections (d) - (f) to §117.475 to address circumvention issues. These new subsections for minor sources are consistent with §117.206(h) for major sources.

BP and TCC stated that the $NO_x$ RACT final control plan required by §117.215 should be invalidated once a site is subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3. BP and TCC expressed concern that submission of revised RACT control plans might be expected, even as the Chapter 101 mass emissions cap and trade program is implemented, resulting in additional paperwork to comply with two different programs.

No changes were proposed to §117.215(e), which requires that the $NO_x$ RACT final control plan be updated with any emission compliance measurements submitted for units using CEMS or PEMS and complying with an emission limit on a rolling 30-day average. The $NO_x$ RACT final control plan was due by November 15, 1999 for sources in BPA and HGA, and final compliance with the RACT requirements for these sources was required by November 15, 1999. Implementation of the Chapter 101 mass emissions cap and trade program will begin on January 1, 2002. However, the emission reductions required by the mass emissions cap and trade program will not be fully implemented until April 1, 2007. The commission agrees that updates to the $NO_x$ RACT final control plan are no longer necessary after that date in HGA. The commission notes that guidance on the final control plans is available on the commission's website at: http://www.tnrcc.state.tx.us/oprd/forms/fcp.html. Changes that could trigger a revision to a final control plan include construction of new units with the same product output as units complying with the source cap, and changes to maximum rated capacities, applicable limits, or assigned limits.

Sierra-Houston supported the revisions to §117.479(h), which add a reference to §117.473(a)(2)(I) to require records of hours of operation for stationary diesel engines claimed exempt due to low annual hours of operation. Sierra-Houston stated that this requirement should apply to emergency and other engines that have some type of operating hours limit.

The commission agrees that the owner or operator of an engine claimed exempt under §117.479(a)(2)(E) or §117.203(a)(6)(D) because it operates exclusively in emergency situations needs to keep records to ensure that operation for testing or maintenance purposes is limited to 52 hours per year, based on a rolling 12-month average, and to document that all other engine operation occurs only during emergency situations, as defined in §117.10. Because run time meters have been included as standard equipment on most stationary diesel engines since approximately 1972, the commission revised §117.479(i) and §117.213(i) to include reference to engines claimed exempt under §117.479(a)(2)(E) and §117.203(a)(6)(D), respectively, because they operate exclusively in emergency situations. For consistency, the commission also added a reference to §117.203(a)(6)(D) in §117.214(a)(2). These changes will require run time meters on these engines; however, the commission is unaware of any such engines that are not already equipped with run time meters. The commission has also revised §117.479(h) and §117.219(f)(6) to include a reference to engines claimed exempt under §117.479(a)(2)(E) and §117.203(a)(6)(D), respectively, and has added a requirement that the owner or operator keep records of the purpose of engine operation, and if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation. Finally, the commission revised the record retention time of §117.479(h) from two years to five years for consistency with §117.479(f) and (j).

No comments were received concerning §117.475(c). However, the commission revised §117.475(c) to clarify that the $NO_x$ emission specifications of §117.475 shall be used in conjunction with §117.475(a) to determine allocations for the mass emissions cap and trade program of Chapter 101, or in conjunction with §117.475(b) to establish unit- by-unit emission specifications, as appropriate. This change is necessary because the existing language could give the impression that all units must meet the $NO_x$ emission specifications of §117.475 on a unit-by-unit basis.

*ESADS - GENERAL COMMENTS*

Since pyrolysis reactors are simply a subset of the process heaters/furnaces category, the commission has combined the proposed §117.206(c)(18)(H) and (I), and has renumbered the subsequent subparagraphs in this paragraph accordingly.

BCCAAG, Dow, and TIP commented on the reference to administratively complete permit applications in §117.106(c) and (c)(5), and §117.206(c) and (c)(18). The commenters stated that the proposed wording uses the term "application" in a manner which could hold an applicant to the emission limits in a permit application, regardless of the limits in the permit as issued.

To address the commenters' concerns, the commission revised §117.206(c) and (c)(18) to clarify its intention that "the lower of any applicable permit limit" refers to limits in any permit issued before January 2, 2001, any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, or any limit in a permit by rule under which construction commenced by January 2, 2001. For consistency, the commission has likewise changed the corresponding wording in §117.475(a) and (b).

*ALTERNATE ESADS*

BCCA, BCCAAG, Dynegy, ED, GHASP, Reliant, and Sierra-Houston noted that the commission has committed to conduct a scientific assessment of the causes of and possible solutions to HGA's nonattainment status for ozone. GHASP commented that the possible consideration of relaxing the point source $NO_x$ rules by June 1, 2002 is unlawful because the commission is obligated to accomplish all feasible rules in the attainment SIP, and the SIP already has a shortfall of 56 tpd of $NO_x$. GHASP recommended that "the unlawful commitment to relax adopted regulatory measures" be deleted, and stated that the commission should only consider relaxing the ESADs in the event that it adopts sufficient rules to achieve attainment and reaches a justifiable determination that attainment can be reached with fewer $NO_x$ emission reductions than required by existing and proposed regulatory measures. ED and Sierra-Houston expressed similar concerns as GHASP's. ED opposed any changes in the ESADs until there is no shortfall in the required emission reductions remaining in the SIP. ED also stated that the alternate ESADs were meaningless since rulemaking would be required to make them effective, and the continuing scientific assessment may not support the 80% level of control in such a rulemaking, which would result in an entirely different set of ESADs. ED further stated that the commission appeared to prejudge the outcome of the scientific assessment by adopting alternate ESADs, even if only on a contingency basis. Sierra-Houston stated that the alternate ESADs were proposed to save industry money and not because the existing ESADs are technically or economically infeasible. BCCA, BCCAAG, Dynegy, and Reliant supported the ongoing scientific assessment of the causes of and possible solutions to HGA's nonattainment status for ozone.

The rule language commits the commission to a scientific assessment of the causes of and possible solutions to HGA's nonattainment status for ozone, and if and to the extent supported by this study the executive director determines that attainment can be reached with fewer $NO_x$ emission reductions from point sources concurrent with additional emission reduction strategies, then the executive director will develop proposed rulemaking and a proposed SIP revision involving alternate ESADs for consideration at a commission agenda no later than June 1, 2002. The alternate ESADs were provided by BCCAAG as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described earlier in this preamble. The Consent Order specifically provides that the "Executive Director may propose . . . the Alternate ESAD Selection Rule, which shall consist of either (1) a rule confirming the . . . 80% Option, or (2) a rule establishing revised ESAD requirements for covered point sources that are different than either the 80% Option" or the ESADs in §117.106(c)(5) and §117.206(c)(1) - (17). Until the scientific assessment is completed in the spring of 2002, it cannot be known if the alternate ESADs will even be implemented and, if implemented, what level of alternate ESADs will be supported by the assessment. If these or other ESADs, or other additional rulemakings, are proposed, the commission will support that proposal with a fiscal analysis and modeling to support any changes to the HGA SIP and the rules in Chapter 117, all of which will be subject to public notice and comment.

The EPA noted that §117.106(c)(5) and §117.206(c)(18) provide that if the total emission reduction required for attainment is determined to be 80% (i.e., lower than currently anticipated), then specified relaxed emissions specifications go into effect. The EPA stated that the rules should be clearer about EPA's role in this process. The EPA commented that §117.106(c)(5) and §117.206(c)(18) require the executive director to prepare a proposed SIP revision, but that there is no reference to the EPA having to approve the relaxed emission specifications before they go into effect as part of the SIP. The EPA expressed the understanding that the commission will submit a SIP revision for any relaxed emission specifications and stated that this action is consistent with the EPA's proposed action on the $NO_x$ point source rules.

Sections 117.106(c)(5) and 117.206(c)(18) already state that the alternate ESADs, if supported by the study, would be implemented through a proposed SIP revision. The SIP revision would be submitted to the EPA for approval. However, the commission is not aware of any of its rules that require EPA approval of a SIP revision before the rules are effective. If the EPA chooses not to approve the SIP revision, they can always enforce the previously-approved version of the rules. This in fact has happened before, in the case of the Chapter 101 upset rules.

ERM suggested that the alternate ESAD for pyrolysis reactors in §117.206(c)(18) clarify that the feedstock heating value is not considered in determining the maximum rated capacity of the pyrolysis reactor.

The commission does not believe that the suggested change is necessary due to the revised definition of "pyrolysis reactor" described earlier in this preamble under the heading of *DEFINITIONS*.

*DIESEL ENGINE TESTING/MAINTENANCE OPERATING RESTRICTIONS*

BP, Sierra-Houston, and TCC opposed §117.206(i) and §117.478(c), which prohibit operation for maintenance or testing of diesel and dual-fuel engines between 6:00 a.m. and noon. BP and TCC suggested that SB 5 of the 77th Legislative Session (2001) may have preempted this control measure along with the construction equipment operating restrictions of Chapter 114, Subchapter I, while Sierra-Houston stated that this will simply delay emissions. ED supported the proposed §117.206(i) and §117.478(c) and stated that these measures will reduce the impact of $NO_x$ emissions from diesel and dual-fuel engines on HGA's peak ozone levels.

The construction equipment operating restrictions of Chapter 114 applied to the normal operations of non-road diesel construction or industrial equipment. In contrast, §117.206(i) and §117.478(c) apply to stationary diesel and dual-fuel engines (which, by definition, have to be in one place for one year to be considered stationary) and do not restrict the normal operation of these engines. Instead, these rules simply prohibit operation for maintenance or testing between 6:00 a.m. and noon. Typically, such engines which are used in emergency situations are on a timer which operates them for 30 minutes to one hour per week, often on Fridays. The timer can be easily changed such that this operation occurs outside the 6:00 a.m.-to-noon window. SB 5 of the 77th Legislature authorized the commission to delete the construction shift requirements from the SIP by October 1, 2001, but did not preempt the commission from adopting time-of-day restrictions on the operation of stationary diesel or dual-fuel engines for maintenance or testing.

The commission agrees with Sierra-Houston that §117.206(i) and §117.478(c) will delay emissions resulting from operation for maintenance or testing of diesel and dual-fuel engines until after noon in HGA. 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 stationary diesel and dual-fuel engines for testing and maintenance, and delaying the release of $NO_x$ emissions until after noon in HGA, 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 stationary diesel and dual-fuel engines 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. The commission made no change in response to the comments.

TECO stated that the manufacturer of its dual-fuel engine has recommended maintenance procedures that include periodic operation for over 24 continuous hours, at which time vibration information is gathered and used to determine the condition of the engine. TECO also stated that every two years the engine is run continuously for five days to allow the engine and associated equipment to heat up so that internal tolerances can be measured. Finally, TECO stated that if a repair was completed to an emergency diesel generator after 6:00 a.m., the proposed rule would not allow testing of the repair until noon, which could lead to a period of up to six hours in which the operability of emergency equipment would be unknown.

The commission revised §117.206(i) and §117.478(c) to allow operation for specific manufacturer's recommended testing requiring a run of over 18 consecutive hours, or to verify reliability of emergency equipment (e.g., emergency generators or pumps) immediately after unforeseen repairs. Routine maintenance such as an oil change is not considered to be an unforeseen repair since it can be scheduled outside the 6:00 a.m. to noon time period.

Shrader stated that operating a diesel engine without it being under load increases the $NO_x$ emissions and also shortens the engine life by about 50%. Shrader suggested that the rule specify that engine operation for maintenance must be done under load.

$NO_x$ formation is primarily dependent on the temperature at which combustion occurs in the engine, with lower temperatures resulting in less $NO_x$ formation. Consequently, diesel engine manufacturers have moved to aftercooling the intake air. With an unloaded engine, the combustion temperatures will be lower and the $NO_x$ formation also lower. While the brake-specific $NO_x$ (grams of $NO_x$ produced per hour divided by the engine output in brake horsepower) may be higher when operating in an unloaded condition due to the much lower output of the engine, the engine's total $NO_x$ output (grams per hour) will be lower than in a loaded condition.

Diesel engines have fuel injection in the form of injectors that meter in a specified amount of fuel into the cylinder based on the engine load. A governor strives to keep the engine at constant speed (revolutions per minute (RPM)) under all loads. As the load increases, more fuel is required to keep the engine at constant speed due to the counter-electromotive force of the generator (counter-torque put on the engine by the generator). As a result, at low loads very little fuel is needed to keep the engine speed constant. Less combustive energy, and thus lower combustion temperatures, result from low fuel rates at low load, and therefore total $NO_x$ formation is reduced. Diesel engine manufacturers do not endorse the operation of engines with no load as this can cause maintenance issues and shorter engine life. There is no rule-of-thumb that quantifies the life expectancy reduction for an engine that is operated unloaded. However, the potential for reduced engine life provides strong motivation for an owner or operator to perform each operation of a diesel engine for maintenance in a loaded condition. The commission made no change in response to the comment.

*SYSTEM CAPS*

Reliant supported the revision to §117.108(c)(1) to allow EGFs the flexibility to choose heat input data from any system 30-day period for the baseline emission calculation.

The commission appreciates the support.

Reliant supported the revisions to §117.109 and §117.570 which give EGFs the additional flexibility to meet the system cap requirements through the use of reduction credits or through the transfer of surplus emission allowables among EGFs participating in a system cap that are in the same nonattainment area.

The commission appreciates the support.

BP stated that the commission should indicate that §117.109 is not intended to limit industrial cogeneration units to system cap trades only.

Section 117.109 applies to any EPGS which is owned or operated by a municipality or a Public Utility Commission of Texas (PUCT) regulated electric utility. Consequently, it does not apply to industrial cogeneration units. The owner or operator of an industrial cogeneration unit is provided the flexibility, under §117.213(f)(4), to use the alternative methods specified in §117.570 for purposes of complying with the system cap of §117.210.

BP and TCC opposed the daily and 30-day system cap of §117.210 and stated that it adds unnecessary complexity to the rule because sources subject to the system cap of §117.210 are also subject to the Chapter 101 mass emissions cap and trade program. BASF stated that §117.210(a) should be revised to clarify that EGFs at industrial sites are not subject to the system cap unless they are peaking units, such as peaking gas turbines or engines as defined in §117.10(35). BASF stated that the majority of stationary gas turbines at industrial sites do not meet the definition of peaking gas turbine in §117.10(35), but operate constantly at base load to provide electricity and steam to dedicated industrial customers with capacity factors greater than 90% and sell electricity to the grid only during periods when those industrial sources are either not operating or operating at reduced load.

BASF and IT noted that §117.210(a) states that EGFs are not subject to §117.210 if electric output is entirely dedicated to industrial customers, and that "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. BASF suggested that this language be changed so that it is based on the annual capacity factor of the EGF, rather than an amount of time during which electricity is sold to the grid. IT stated that there are several instances where cogeneration facilities must provide service to the grid for longer than two weeks per year at a very reduced load (on the order of less than 5.0% of capacity), and that these instances are due to the fact that many cogeneration facilities must continue to provide their industrial customer hosts with a minimum amount of steam (while generating a corresponding minimum amount of electricity to the grid) even when the host's load sources are not operating. IT stated that the level of emissions generated during these periods is very insignificant but occurs over an extended period of time (i.e., greater than two weeks). IT suggested that two weeks per year of service to the electric grid be calculated as "a generation amount equivalent to two weeks at nominal EGF nameplate capacity." Alternatively, IT suggested that "entirely dedicated" could be simply stated as "less than a specified portion (e.g., 5.0%) of generation capacity is utilized in providing service to the grid during a year" or "less than a specified portion (%) of the 1997-1999 generation total is provided to the grid during a year."

Cogeneration units generate power which in some cases is sold to the grid and in other cases is normally dedicated to use by a manufacturing process. Cogeneration units which provide power to a dedicated industrial load sometimes provide power to the grid when the manufacturing process is not operating. This type of cogeneration operation is not adding additional emissions during peak electric demand and ozone periods.

Cogeneration units which provide power to a dedicated industrial load may also provide power to the grid for longer than two weeks per year at a very reduced load because these units must continue to provide their industrial customer hosts with a minimum amount of steam (while generating a corresponding minimum amount of electricity to the grid) even when the host's load sources are not operating. This type of cogeneration operation is not adding additional emissions during peak electric demand and ozone periods since these units would be producing power if the host's load sources were operating.

However, EGFs 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 units should comply with the daily cap. For EGFs which operate as peaking units, 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 more difficult 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.

In response to the comments, the commission has modified the system cap requirements in §117.210 by adding another option to the last two sentences of §117.210(a). The new language excludes each EGF that generates electricity primarily for internal use, but that during 1997 and all subsequent calendar years transferred (or will transfer) that generated electricity to a utility power distribution system at a rate less than 3.85% of its actual electrical generation (which represents two weeks' worth of electrical generation per calendar year). These EGFs are base load units 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, the commission believes it is appropriate to exclude these units from the system cap.

BCCAAG and Entergy commented on the new §117.210(c)(2) which takes into account the fact that utility EGFs generally have their highest output during the summer months, while industrial cogeneration units may have higher output during non-summer months. BCCAAG and Entergy suggested that §117.210(c)(2) be revised to clarify that the baseline period is a 30-day period for consistency with §117.210(c)(1) and §117.108.

The commission's intention is that the baseline period is a 30-day period. Consequently, the commission made the suggested change by adding "the system highest 30-day period" to the term $H_i$ in the figure in §117.210(c)(2).

BASF suggested that §117.210 specify that $NO_x$ emissions from duct burners (on cogeneration units subject to §117.210) are not subject to the system cap requirements if the duct burners do not generate electricity sold to the grid.

The commission does not believe that the suggested change is necessary due to the revisions to §117.210(a) described earlier in this preamble under the heading of *SYSTEM CAPS* which are intended to exclude base load EGFs from the applicability of the system cap in §117.210.

BCCAAG stated that the system caps of §117.108(c) and §117.210(c) should include a provision for the additional heat input that may be required to operate affected EGFs as a result of the installation of emission controls. BCCAAG suggested that the wording "plus the calculated additional daily heat input required by the addition of $NO_x$ controls to comply with this chapter" be added to the 30-day baseline heat input in §117.108(c)(1) and §117.210(c)(1) and (2). BCCA stated that an example of a case where additional heat input is needed would be gas turbines in which steam injection is part of the compliance strategy.

There are inherent difficulties in such an approach, such as how to calculate the additional heat input, how enforcement personnel would be able to distinguish between controls added earlier and modifications made to comply with the ESADs, etc. In the commenter's example, it should be noted that as of November 15, 1999, gas turbines became subject to the $NO_x$ RACT limit of 42 ppmv, which is typically met through the use of DLN or steam or water injection. The commission made no change in response to the comment.

Sempra commented on the calculation of variable $H_i$ (heat input) in the 30-day rolling average emission cap equations of §117.210(c)(1) and (2). Sempra stated it would not expect the first two consecutive third quarters of operation of its new EGFs to be a reasonable long- term predictor of the cap values due to possibly reduced operation associated with slow-developing market demands or cooler-than-expected weather. Sempra stated that a two-year extension for baseline determination is preferable to the current baseline but may not be sufficient to allow new power plants serving a high-growth area, such as Montgomery County, to accumulate sufficient operation time to determine a representative baseline, which Sempra believes could force the more efficient new units into a situation where they must either limit operation and defer to older and dirtier units, or purchase allowances. Sempra stated that this is not consistent with promoting environmental benefits and energy reliability. Sempra expressed a preference for a seven-year extension, and also suggested the use of values based on full (100% generation) load.

In response to the comments, the commission revised the rolling 30-day average emission caps of §117.108(c)(1) and §117.210(c)(1) and (2). Specifically, the commission revised §117.108(c)(1) by modifying the method of determining level of activity for new electric utility EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. Similarly, the commission revised §117.210(c)(1), applicable during July - September, by modifying the method of determining level of activity for new non-utility EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. Finally, the commission revised §117.210(c)(2), applicable to non-utility EGFs during months other than July - September, by modifying the method of determining level of activity for new EGFs. Owners or operators of EGFs that are in this category may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. For an EGF for which the system highest 30-day period in the first two years of operation occurs in months other than July - September, the owner or operator may substitute the system highest 30-day period in the six months comprising the highest three consecutive months in any two consecutive years in the first five years of operation.

For the rolling 30-day average emission caps of §117.108(c)(1) and §117.210(c)(1) and (2), the five-year period begins at the end of the adjustment period as defined in §101.350, concerning Definitions. The 180-day adjustment period addresses that period of time from first start-up to establishment of normal operating conditions for a new facility. In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period. A principal goal is to provide incentive to make emissions reductions. The commission believes that owners or operators who install and operate cleaner equipment should have the opportunity to fully integrate that equipment at a realistic level of operation that is representative of the demands that will be placed on the equipment. The commission believes that a five-year period to establish a baseline will allow this integration, while timely establishing the necessary emissions cap. This is consistent with the corresponding revisions to §101.353 which add the option of a five-year period to establish a baseline and the availability of an additional two-year period in extenuating circumstances.

*EXEMPTIONS*

EDI and Sierra-Houston commented on the deletion of the exemption for small (ten MW or less) electric generating units which are registered under a standard permit. Sierra-Houston supported the deletion of this exemption, while EDI requested that this exemption be retained for small electric generating units which are fired on landfill gas. EDI stated that the commission should retain the exemption because small electric generating units which are fired on landfill gas are pollution control devices; it is a replacement for the host landfill's existing control device (i.e., a flare); and it is a replacement for a part of the generation capacity of a conventional power plant. EDI stated that if the commission deletes the exemption for small electric generating units which are registered under a standard permit, it should raise the emission specification for landfill gas-fired engines and should provide credit for $NO_x$ emission offsets.

Landfill gas-fired engines which are also electric generating units serve a dual function of control device (destruction of methane and VOC emissions) and process unit (generation of electricity). Other units serve a dual purpose, such as BIF units which are used both as boilers (steam production) and as incinerators (destruction of hazardous waste), and are subject to ESADs. Other units which are control devices, such as thermal oxidizers, are subject to ESADs. It is inequitable to create a protected source class which is not subject to the Chapter 101 mass emissions cap and trade program. Indeed, because these electric generating unit emissions would not be subject to the cap and trade program, such a protected source category would permit continued growth in emissions, thereby jeopardizing the SIP. Further, the additional generating capacity represented by small electric generating units which are fired on landfill gas would not necessarily result in a replacement of part of the generation capacity of a conventional power plant in HGA, since the additional power generated could simply be transmitted outside HGA and reduce the load on a power plant outside HGA.

The commission proposed and has adopted an ESAD of 0.60 g $NO_x$/hp-hr for stationary engines which are fired on landfill gas. The existing ESADs for gas-fired rich-burn and lean-burn engines are based on use of flue gas cleanup and remain the ESADs for those engines not fired on landfill gas. However, landfill gas contains siloxanes which rapidly poison the catalyst of flue gas cleanup controls. The revised ESAD for stationary engines which are fired on landfill gas is based upon combustion modifications and is necessary to ensure that the ESAD for these engines is technically feasible.

Topsoe stated that some units which are categorized as process heaters, such as reformers, may be operated for research and development (typically described as pilot plants) rather than for production. Topsoe stated that pilot plants usually operate intermittently, in contrast to the near- continuous operation of production units. Topsoe also stated that the use of control equipment on critical process equipment can significantly affect the pilot plant's ability to reproduce customers' equipment configurations, making it difficult to develop process data that is consistent with the customers' needs. Topsoe further stated that pilot plants have been exempted in other commission rules and that pilot plants are "usually very small sources." Topsoe suggested that an exemption for pilot plants be added to §117.203.

The commission disagrees with the suggested concept of including a broad exemption for pilot plants in the rules. Such a concept would not ensure that the necessary emission reductions occur. However, based on previous comments, the commission included exemptions in Chapter 117 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. For example, §117.106(c)(4) and §117.206(c)(17) and (18)(Q) include alternative ESADs which are based on Tier I controls. The limit is the lower of any applicable permit limit or 0.06 lb/MMBtu for any unit 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. Also, if pilot plants are "usually very small sources," then presumably very few emission credits would be needed should the owner or operator make a decision not to equip them to meet the ESADs.

Sierra-Houston supported the 52 hours per year cutoff for operation for testing or maintenance purposes in the exemptions for existing (before October 1, 2001) stationary diesel engines in §117.203(a)(6)(D) and §117.473(a)(E).

The commission appreciates the support.

Shrader and Sierra-Houston commented on the 100 hours per year cutoff in the exemptions for existing (before October 1, 2001) stationary diesel engines in §117.203(a)(11) and §117.473(a)(H) and for new, modified, reconstructed, or relocated stationary diesel engines in §117.203(a)(12) and §117.473(a)(I). Shrader expressed concern that this would not allow enough hours of operation in the event of emergencies, such as the flooding which occurred in Houston in late spring 2001, while Sierra-Houston supported the cutoff.

The referenced exemptions are for engines which do not operate exclusively in emergency situations. For example, backup generators which also operate as peak shavers would be able to operate in peak shaving mode for approximately 48 to 74 hours per year, assuming weekly maintenance operation of 30 minutes to one hour. Existing engines which operate exclusively in emergency situations, as defined in §117.10(14), continue to be able to operate as many hours as necessary in these situations. For any new, modified, reconstructed, or relocated stationary diesel engine placed into service in HGA on or after October 1, 2001, the commission agrees that an allowance should be made for emergency situations. Therefore, the commission revised §117.203(a)(12) and §117.473(a)(I) to specify that the 100 hours per year cutoff applies to operation in non-emergency situations. This allows operation of stationary diesel engines during an emergency situation for as many hours as the emergency situation, as defined in §117.10(14), continues to exist.

*MONITORING REQUIREMENTS*

BP suggested that the CEMS requirements of §117.213(e) be revised to include an option of testing under 40 CFR 75, Subpart E, because of the potential of failing an initial relative accuracy test audit (RATA) test when a source is operating at very low $NO_x$ concentrations (e.g., five to ten ppmv). BP commented that 40 CFR 60 looks at relative accuracy in terms of percentage instead of an absolute value, whereas 40 CFR 75 allows the use of an absolute difference.

No changes were proposed to §117.213(e). However, the commission anticipates initiating rulemaking after October 15, 2001 to address this issue, along with a variety of other minor clarifications that were not included in the current rulemaking.

*COMPLIANCE SCHEDULE*

TECO commented on §117.520(c)(2)(A)(i), which specifies that the owner or operator must install any totalizing fuel flow meters, run time meters, and emissions monitors required by §117.214 as soon as practicable but no later than the time of installation of emission controls on each unit (or March 31, 2005 if construction of controls has not commenced by that date). This proposed rule further specifies that if emission controls on a unit will consist of both flue gas cleanup (for example, controls which use a chemical reagent for reduction of $NO_x$) and combustion controls, then for the purpose of determining when emissions monitors must be installed, "time of installation" means the time of installation of flue gas cleanup. TECO questioned when emissions monitors (CEMS or PEMS) must be installed if combustion controls, but not flue gas cleanup, are installed.

The intention is that if flue gas cleanup (such as SCR or SNCR) is installed, then the emissions monitors required by §117.214 must be installed at the time of installation of flue gas cleanup or by March 31, 2005 (whichever occurs first), regardless of whether or not combustion controls are later installed. If only combustion controls are installed on a unit, then the emissions monitors required by §117.214 must be installed by March 31, 2005. If installation of emission controls (whether combustion controls, flue gas cleanup, or both) has not begun by March 31, 2005 on a unit for which §117.214 requires emissions monitors, then the required emissions monitors must be installed by March 31, 2005. The commission revised §§117.510(c)(2)(A)(i), 117.520(c)(2)(A)(i), and 117.534(1)(A) and (2)(A) to clarify this intent.

BCCAAG stated that the compliance schedule for non-utility EGFs subject to the system cap of §117.210 limits flexibility for owners and operators by singling out this particular source category and putting it on a specific schedule, in effect accelerating EGF retrofits to a fixed schedule driven by the first or second emission reduction milestone. In contrast, BCCAAG noted that these same owners and operators had the flexibility to schedule retrofits for their non-EGF sources in the most economical and efficient manner possible. BCCAAG suggested revisions to §117.520(c)(2)(B) and (C) which would make the §117.210 system cap a requirement for a given EGF only at the time that emission controls are installed on the unit.

The commission has made the suggested revisions to §117.520(c)(2)(B) and (C). In addition, the commission made revisions to §117.210(a), described earlier in this preamble under the heading of *SYSTEM CAPS*, which are intended to exclude base load EGFs from the applicability of the system cap in §117.210. The revisions to §117.210(a) and §117.520(c)(2)(B) and (C), in conjunction with the addition of another step in the emission reduction schedule in the mass emissions cap and trade program, will afford owners and operators of base load cogeneration facilities additional flexibility in scheduling retrofits to meet the ESADs of §117.206(c).

BASF stated that the compliance schedule in §117.520(c)(2)(B)(iii) for non-utility EGFs subject to the system cap of §117.210 should be revised to coincide with the reduction schedule in §101.353(a)(3).

The existing compliance schedule is consistent with §101.353. For example, the first emission reductions must be achieved by March 31, 2004 in order to comply with the existing §117.520(c)(2)(B)(iii)(I) and §101.353(a)(3)(C)(ii). As described in the response to the previous comment, the commission revised §117.520(c)(2)(B) and (C). These revisions ensure consistency with §101.353.

ED and GHASP objected to the addition of another step in the emission reduction schedule in §117.520(c)(2)(B)(iii) for non-utility EGFs subject to the system cap of §117.210. ED stated that the revised schedule is not as expeditious as practicable and that there is no compelling reason for the revised schedule.

The commission adopted this change to allow the affected industries more options for planning and implementing incremental reductions in emissions. This schedule is practicable given the financial and technical resources necessary by individual companies and all sources in the HGA ozone nonattainment area to comply with the required emission reductions. The amendment would not affect the March 31, 2007 final compliance date nor would it increase final emission rates, and would still achieve the final emission reductions as required by the SIP. This change is necessary for consistency with the corresponding changes to §101.353 adopted elsewhere in this issue of the *Texas Register*. The revised compliance schedule was provided by BCCAAG as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described earlier in this preamble.

McAngus testified that "there will not be enough resources available, especially in the time frame required, for industry to be able to install, purchase, and construct all the controls required to meet the ESAD limits." McAngus further testified that "I'm sure there will be some increase" in the marketplace in response to the increased demand for resources. "For example, catalyst manufacturers will attempt to make as much catalyst as they can so they can sell it." However, McAngus testified that he believes that catalyst manufacturers "will build plants enough that they will be able to satisfy the replacement of catalysts," and not "the very high levels required for the short, two- or three-year time frame." McAngus testified that he believes this is true in the case of engineering and construction resources as well. Deason testified that there is a probable shortage of the engineering resources needed to do all of the "individual equipment-specific analysis, potential shortages of both burners and catalyst, as well as a number of other key resources that are needed to actually physically implement" the reductions in the time required. Hamilton testified that a study commissioned with a consultant by the BCCA (*Houston-Galveston Area State Implementation Plan Resource Availability Study* (August 2000)) itself did not deem the construction and engineering resources to be a critical constraint. Hamilton testified further that he had discussions with catalyst suppliers concerning resource availability, and that discussions with others revealed that some companies are interested in the business opportunity in catalyst manufacturing presented by the rules.

Deason's and McAngus's comments are based, in part, on an overestimate of the number of SCRs that will be installed and an underestimate of the time frame during which the SCRs will be installed. 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 in 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 existing ESADs and further details of the technical feasibility of the ESADs can be found elsewhere in this preamble and in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)). 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 contemplated in the preamble to the Chapter 117 proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275). Although the number of SCRs is expected to be unprecedented, the ultimate number installed is almost 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 existing rules gives 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.

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. This should further address concerns regarding catalyst availability. In addition, it should be noted that a study commissioned with a consultant by the BCCA (*Houston-Galveston Area State Implementation Plan Resource Availability Update* (April 16, 2001)) incorrectly states that the "$NO_x$ reduction SIP for HGA has mandated the 90% $NO_x$ reduction over a three-year period, one-third by the end of 2002, one-third by the end of 2003, and one-third by the end of 2004." In fact, the $NO_x$ reductions required of point sources occur in annual steps beginning in 2003 and continue until 2007, a five-year period, and not over the "short, two- or three-year time frame" as stated by McAngus or assumed in the BCCA study's discussion of catalyst availability. Therefore, McAngus and the study underestimate the time frame during which the SCRs will be installed, which in turn overstates the catalyst demand in 2003 and 2004.

Deason testified that deadline-driven milestones cause ExxonMobil to take units "out of service at unplanned outages," which prevents them from being able to "do projects from the least cost first, to the highest and most difficult last." Deason testified further that ExxonMobil can not delay the more expensive reductions due to milestones that are requiring ExxonMobil to do things early, and also due to their planned outage schedule.

It is unclear from this testimony exactly what milestones are requiring ExxonMobil to make emission reductions early. However, it should be noted that the commission added another step in the emission reduction schedule in §117.520(c)(2)(B)(iii) for non-utility EGFs subject to the system cap of §117.210. The commission also added another step in the emission reduction schedule in §101.353 (adopted elsewhere in this issue of the *Texas Register*). The commission adopted these changes to allow the affected industries more options for planning and implementing incremental reductions in emissions. The amendment would not affect the March 31, 2007 final compliance date nor would it increase final emission rates, and would still achieve the final emission reductions as required by the SIP. The revised compliance schedule was provided by BCCAAG as part of the "Consent Order" submitted to Judge Margaret Cooper, Travis County District Court, in the lawsuit styled BCCA Appeal Group, et al v. TNRCC, as described earlier in this preamble.

*COST*

BCCA and BCCAAG stated that the controls required to achieve a 90% reduction are not economically feasible, as required by the TCAA. BCCA and BCCAAG submitted an economic analysis report, *Cleaning Up Houston's Act: An Economic Evaluation of Alternative Strategies* (December 2000), which was commissioned by BCCA, and requested that it be used for the cost-benefit analysis that the commission is required to perform on all new rules. BCCAAG also submitted a January 2001 updated version of this report. BCCA and BCCAAG stated that the TCAA requires the commission to "consider the facts and circumstances bearing on the reasonableness of emissions, including the source's social and economic value, and the technical practicability and economic reasonableness of reducing or eliminating the emissions resulting from the source." A witness, Barton Smith (Smith), testified that a presentation summarizing the information contained in the report was not provided to the commission until November 10, 2000, while September 25, 2000 was the date the comment period closed for the SIP and rule proposals for which the report was developed. A witness, Jeff Saitas, testified that the economic feasibility of controls is a factor that the commission must consider as part of the SIP development process.

The commission appreciates BCCA's and BCCAAG's submittal of an economic analysis report. The commission agrees with Smith that the information contained in the BCCA report was not provided to the commission until well after the comment period closed for the SIP and rule proposals for which the report was developed. The commission also notes that the BCCA report was not completed until after the adoption of these rules and SIP on December 6, 2000. The commission based the existing ESADs on its own analysis of cost and technical feasibility, which included seeking factual input from the regulated community. Nevertheless, a cursory review of the BCCA report revealed that while the underlying economic principles and theories outlined in the BCCA report are reasonable and theoretically sound, the application of these principles into the analysis is flawed in a variety of ways, and the report lacks sufficient documentation and detail. Some of the key issues in the report that are questionable are described in the following paragraphs.

It should be noted that the BCCA report begins with the statement that "during the past year," the authors "have been conducting a study examining the impacts" of the SIP on the Houston economy, thereby implying that the report took an entire year to prepare. Because the SIP and associated rules were not proposed until August 2000, while the report is dated December 2000 (initial version) and January 2001 (updated version), the authors' claim to have been developing their study "during the past year" is overstated.

The BCCA report asserts that the estimated total costs of the measures in the SIP are approximately $4.1 billion (year 2000 dollars) annually in 2007, yet a large number of the measures included in the cost estimate were never adopted by the commission (for example, rules for diesel emulsions, air conditioners, airport ground support equipment, and $NO_x$ reduction systems) or have been repealed as part of the implementation of SB 5 (relating to the Texas Emission Reduction Plan) of the 77th Texas Legislature, 2001 (construction shift rules and accelerated Tier 2/Tier 3 purchase rules, which the BCCA report cited as two of the most onerous requirements (totaling $1.8 billion in annual costs, according to the BCCA report)). Despite the fact that these control measures were never adopted or were repealed, the costs for these measures continue to be included in the BCCA reports's total estimated cost of the SIP. The costs for these control measures are irrelevant and should be deleted.

Further, the sources and estimation process for the cost study are largely undocumented. The report states that the commission's cost estimates were 'fragmentary and insufficient,' and therefore the authors consulted a number of sources in estimating the costs of the SIP, including the commission, BCCA, industry, EPA, and RCF, Incorporated. However, specific documentation for individual regulatory measures are not presented in the report. Due to the lack of documentation and explanation, it is not possible to evaluate the reasonableness of the BCCA report's individual measure cost estimates. For example, with regard to the 55 mile per hour speed limit, the report mentions the costs incurred by households (in the form of taxes and the time costs of longer commutes). One presumes (though it is not explicitly stated) that these costs are components of the BCCA report's estimates, yet the report does not quantify or even mention the benefits associated with reduced traffic accidents and reduced traffic-related fatalities due to the speed limit reduction.

In addition, the BCCA report used a discount rate of 12.5% and an expected useful equipment life of ten years to estimate the annualized portion of capital costs for the rule. The discount rate and the useful life of the equipment are unsubstantiated and presented as assumptions. The BCCA report did not include conducting sensitivity analyses to quantify the impact of these assumptions on the model results. It should be noted that an EPA guidance document, *OAQPS Control Cost Manual (EPA 453/B-96-001*, February 1996), states on page 2-11 that the control system life "typically varies from 10 to 20 years." By selecting the lower value of this range, the BCCA report may have inflated the annualized portion of control equipment capital costs, thereby exaggerating the cost of the SIP and associated rules.

The BCCA report uses the regional economic model developed by Regional Economic Models, Incorporated (REMI) to estimate the impact of the regulations on the Houston economy. Economic impacts including potential changes in employment, Regional Gross Domestic Product, local and state tax receipts, local cost of living, wages and salaries, and real disposable income per capita and impacts on business sectors and households are estimated using the REMI model. One key assumption of the analysis is that the point source measures in the SIP are so restrictive that growth in the affected sectors will cease to occur after implementation of the regulations.

Regarding the report's analysis of effects of the SIP on the Houston economy, the commission agrees that the REMI model used in the report is a reasonable one to use to analyze the impacts of the attainment demonstration SIP on the Houston economy. The model is well documented and has been used to analyze many policy issues. However, any economic model is no better than the underlying data used as inputs to the model. The fact that a large number of regulations included in the cost estimates were never adopted by the commission (or have been repealed) and are erroneously included in the costs used to estimate the impacts; and the fact that the cost estimates are largely unsubstantiated or documented make the REMI model results dubious.

The key assumption that the point source measures prohibit growth in the affected sectors is quite significant to the REMI model results. The report states this as a fact, but provides little support for this assumption. Although a number of sensitivity analysis are conducted of alternative regulatory strategies, the BCCA report does not include a sensitivity analysis to quantify the impact of this significant assumption on the REMI model results. As described later in this preamble, Smith's testimony acknowledged that the BCCA report which he co-authored concluded that the HGA SIP rules merely slow, but do not stop, the continued growth of the Houston economy as a whole. It should also be noted that the BCCA report does not include a scenario in which the SIP is replaced by a federal implementation plan.

Regarding the BCCA report's analysis of air quality benefits of the SIP, the BCCA report uses a rollback model to estimate air quality benefits associated with the SIP. This rollback method "posits that reductions in ozone levels in excess of the background ozone level are proportional to changes in Houston area $NO_x$ emissions." Using this rollback method, the authors determined the ozone reductions required to meet the standard by reviewing data for the period 1997 to 1999 and comparing the fourth highest hourly ozone reading during this period to the ozone NAAQS standard in parts per billion (ppb). The authors then used this difference to construct a reduction in annual average ozone resulting from the SIP and considered the difference in these ozone levels to represent the air quality benefits of the SIP. The report acknowledges that more sophisticated air quality approaches potentially would yield different benefit values. However, the report asserts that the relatively small size of the benefits as compared to the costs of the SIP would likely be affected very little by alternative methods. The report's next step in benefits estimation is to value ozone reductions. The report's approach concentrates strictly on ozone health benefits. The report considered 21 studies included in the EPA publication "The Costs and Benefits of the Clean Air Act: 1990 - 2010" as reasonable studies to consider for estimation of the morbidity responses to ozone changes in HGA. Representative population values (such as a total Houston population of 4,218,139) are related to the study values. The report's final step was to place a monetary value on the symptoms identified in the 21 studies and to combine studies to estimate total benefits. Based upon this scenario approach, the authors concluded scenarios with total benefits of $40 million annually are most representative for the report.

Regarding the BCCA report's air quality rollback approach, the assumption that reductions in ozone are proportional to changes in $NO_x$ emissions is questionable given that the ozone formation process is highly nonlinear. Health benefits depend upon the distribution of ozone levels during the season and during different averaging times not explicitly considered in the report.

Although cost, benefits, and economic impacts are estimated in future years, the BCCA report's air quality estimates are based upon historical data (1997 - 1999). The report used the REMI model to estimate impacts of the SIP, and this model assumes that growth in economic activity will occur during the study period. This growth in economic activity will likely cause $NO_x$ emissions to increase (all other factors held constant), and this growth in emissions is not accounted for in the rollback approach calculation or in benefit estimates. Likewise, implementation of regulations other than those in the SIP that may occur after the 1997 - 1999 period, thereby decreasing $NO_x$ emissions, are not considered with this approach.

$NO_x$ emissions are transported into and out of HGA, and this transport is not explicitly considered in the air quality method used in the BCCA report. The SIP is expected to lower $NO_x$ emissions transported from HGA to areas outside of HGA, and the benefits of these $NO_x$ reductions are not accounted for in the report's approach. For example, both BPA and DFW are depending on emission reductions from HGA for their attainment demonstration SIPs and associated attainment date extensions to 2007. Near nonattainment areas such as Austin and San Antonio will also benefit from the emission reductions required by the Houston attainment demonstration SIP as these areas try to avoid exceeding the one-hour ozone standard and prepare for the implementation of the eight-hour ozone standard, yet the BCCA report failed to consider this benefit. The BCCA report also fails to take into account the benefit of the SIP as compared to the costs of the federal implementation plan that EPA is required to develop if the commission does not implement an acceptable (to EPA) attainment demonstration SIP.

Regarding the BCCA report's valuation of ozone reductions, it should be noted that the report does not consider important dose-response functions. For example, lost worker productivity is not considered as a benefit category in the report. This category is likely one of importance in HGA.

The report does not consider ozone mortality benefits in the estimate of SIP benefits. The report states that "we agree with the U.S. EPA's cautionary note regarding the possibility of spurious correlations if attempts are made to relate ozone to mortality" in the EPA publication "The Costs and Benefits of the Clean Air Act: 1990 - 2010." What the BCCA report fails to recognize is that PM mortality benefits are considered in this EPA study. The omission of ozone mortality benefits from this EPA study recognizes the possibility of double counting ozone mortality benefits when the PM mortality benefits are included in the benefits estimate. However, the interpretation in the BCCA report that ozone mortality benefits do not exist and should not be considered is incorrect.

Further, the BCCA report ignores specific categories of benefits in the benefit estimates. Ecological benefits including the beneficial impact of ozone reductions on forests and agriculture and decreased nitrogen deposition to estuaries are not addressed in the study.

Finally, the BCCA report uses population estimates in the valuation of benefits that appear to be historical estimates (note that the year is not documented in the report), rather than the forecasted population estimates for the year of analysis. For example, it seems reasonable to use forecasted 2007 populations to estimate the benefits of the SIP in 2007, and it is not clear this approach is followed in the BCCA report.

Deason testified that retrofits are more difficult due to space considerations. Deason further testified that improved burner performance to reduce $NO_x$ emissions typically results in use of larger burners, and that as a result the burners can not be replaced in the existing hole or the floor spacing. Deason testified that this means the floor must be redesigned and that often fewer burners than originally equipped must be used, which in turn can cause reduced capacity. Deason also testified that in some cases the lack of available space would mean that an SCR would have to be elevated, and existing structural supports may be inadequate to support the SCR. In some cases what appears to be open space is actually used for maintenance turnarounds and is not actually available.

There is no one specific 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. Replacement of existing burners is but one control technology option. The commission agrees that retrofits can be expected to be more difficult than new installations. However, as described elsewhere in this preamble as well as in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)), the existing ESADs are technically feasible. The difference between retrofits and new installations relates more to potential cost and the need for a reasonable compliance schedule to implement the retrofits than to the technical feasibility of the ESADs.

As discussed in several responses in this section as well as in the preamble to the adoption of the existing ESADs on December 6, 2000, 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 SCAQMD, because a stream of new permits is issued at lower rates after a new level of $NO_x$ is demonstrated. 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.

The commission analyzed the technical feasibility of each existing ESAD and did not adopt any it believed to be technically infeasible. There are a vast number of point sources in HGA, 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. In the preamble to the adoption of the existing ESADs on December 6, 2000, the commission re-examined the issues of technical feasibility in response to public comment and, after considering the technical feasibility issues raised by commenters, adjusted several ESADs where it believed the case has been made that the level of control is not demonstrated and may be impracticable.

McAngus testified that of the nine California process heaters cited by the commission in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)) as meeting the ESADs (three at Chevron (El Cerrito) and six at Mobil (Torrance)), "we contacted each of these facilities and talked to them...." and "all three of {the Chevron} furnaces were new facilities that had been built in the early '90s" and "the SCRs had been designed into the original design of this process, so it was not a retrofit condition." McAngus testified that "in the situation for Mobil, there were six furnaces," and "five of the six" were new facilities. McAngus suggested that information from SCAQMD in response to a November 27, 2000 email was not accurate because the units referenced that are meeting the ESADs are new, not retrofits, and therefore the cost analysis "underestimated the true cost to the industry." Hamilton testified that if these process heaters were in fact new units rather than retrofits, they would be useful as examples of units that are "actually in operation achieving levels lower than the adopted emission standard," and therefore, still would be significant. Hamilton testified that the difference between retrofits and new units is "significant in terms of cost, but not in terms of technical feasibility."

The commission agrees that retrofits can be expected to be more difficult than new installations. However, as described elsewhere in this preamble as well as in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)), the existing ESADs are technically feasible. The difference between retrofits and new installations relates more to potential cost and the need for a reasonable compliance schedule to implement the retrofits than to the technical feasibility of the ESADs.

On August 15, 2001, a SCAQMD representative confirmed McAngus's testimony (described earlier in this preamble under the heading of *ESAD - ICI BOILERS AND PROCESS HEATERS*) that one of the six process heaters meeting the ESADs at the ExxonMobil refinery in Torrance is a retrofit. Specifically, the SCAQMD representative advised that heater 924 at this ExxonMobil refinery was retrofitted with an SCR unit in 1992. On August 15, 2001, the SCAQMD representative also confirmed that the three process heaters meeting the ESADs at the Chevron refinery in El Cerrito were retrofitted with a common SCR unit in 1994. The commission agrees with Hamilton that the five process heaters which were new units rather than retrofits are useful as examples of units that are in operation achieving emission levels below the existing ESAD.

McAngus testified that "we did a review of historical BACT evaluations and looked at the costs the agency had accepted, and particularly for facilities in HGA," and "found that {BACT} costs that were acceptable to the agency... during the 1990s to the present... primarily were around $1000 per ton for $NO_x$ emissions." McAngus testified that one case was about $11,000 per ton, but "costs that were rejected as being economically unreasonable... were anywhere from $5000 up to maybe $50,000 per ton." McAngus testified that the costs to comply with the ESADs are "much higher" than BACT costs "that typically have been accepted by the agency." McAngus testified further that BACT is only used in permits and not rules.

By definition in §116.10(3), BACT gives consideration "to the technical practicability and the economic reasonableness of reducing or eliminating emissions from the facility." Under §116.111(a)(2)(C), concerning General Application, BACT applies statewide to anyone who proposes a new facility or modifies an existing facility that will or might emit contaminants to the air in Texas. The commission agrees that BACT is only used in NSR preconstruction authorization under Chapter 116, Subchapter B, New Source Review Permits, and not Chapter 117. BACT determinations are made on a case-by-case basis.

Permit review for major source construction and major source modification in nonattainment areas requires controls that represent LAER. LAER is defined in §116.12, concerning Nonattainment Review Definitions, to include "(A) the most stringent emission limitation which is contained in the rules and regulations of any approved SIP for a specific class or category of facility, unless the owner or operator of the proposed facility demonstrates that such limitations are not achievable; or (B) the most stringent emission limitation which is achieved in practice by a specific class or category of facilities, whichever is more stringent," and therefore is generally expected to be more stringent than BACT.

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 existing 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 a result, the existing ESADs are technically feasible, albeit admittedly stringent, standards which represent maximal point source $NO_x$ controls necessary for HGA to attain the ozone NAAQS. There is no question that in some cases the ESADs are more stringent than BACT or even LAER because the goals of the various requirements are different, as described earlier in this preamble. It is therefore not unexpected that the cost to comply with the ESADs is likely to be higher than historical BACT costs.

McAngus testified that the cost estimates in the Chapter 117 cost note published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) underestimated the "true cost to the industry." McAngus testified that "many of the costs that were cited were based on data in the early 1990s, and there was no attempt to bring those costs up to" current (2000) dollars, and that "just doing a simple CPI {consumer price index} index of those numbers, the numbers were probably low by 25 to 30%, just based on inflation." McAngus testified further that "there were also other operating cost data that were using old prices as opposed to current day prices." McAngus testified that the estimated costs for FCCUs in the Chapter 117 rule proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) are inaccurate because "these costs were actually coming from what appear to be utility boiler costs, so it's a completely different category." McAngus testified that based on his conversations with people at the plants with the 13 FCCUs, the cost to retrofit FCCUs with SCR "appears to run between $20 to $60 million per installation," and that "even the installation of one of these SCRs" on an FCCU "is more than the whole cost that {the commission} estimated for the category." McAngus testified that the cost estimates for ethylene furnaces in the Chapter 117 rule proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) underestimated the costs. McAngus testified that based on his discussions with the owners of 70 of an estimated 200 ethylene furnaces, "the costs were ranging between $4 to 6 million dollars per furnace," so the cost to retrofit ethylene furnaces would be "close to $1 billion, which again is more than the entire category" of process heaters. McAngus testified that the cost estimates for gas turbines in the Chapter 117 rule proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) underestimated the costs. McAngus testified that the commission estimated the cost to retrofit turbines with SCR to average about $2,500 per ton, while his discussions with the owner of a site "that has over 30 turbines" revealed that the company had done "an engineering study and found that the costs were going to be... almost $70,000 per ton."

The commission used the most recently available cost data and cited the source of the data. While the cost of certain items may have changed since the year of the data that the commission cited, the commission continues to believe that this approach is appropriate for the reasons delineated in this response to McAngus's comments.

The commission disagrees with McAngus's claim that "many of the costs that were cited {in the Chapter 117 cost note published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275)} were based on data in the early 1990s." In fact, the vast majority (over 75%) of the estimated costs in the August 25, 2000 rule proposal were based on June 1998 or newer data. There is no reason to expect that any changes in cost from June 1998 to August 2000 would be significant, especially given that the cost of pollution control equipment has generally been declining as more controls are installed and operating experience is gained. In addition, it appears that McAngus has overstated the effect of inflation. Specifically, even if the cost of controls increased from

1993 (the earliest of the references cited in the Chapter 117 cost note published in the August 25, 2000 issue of the *Texas Register*) until 2000, what is relevant is the cost of those controls relative to other costs. For example, if the cost of an item increased over a period of time by the average inflation rate, that item's cost would be unchanged relative to the average cost of other items.

The consumer price index (CPI) is a measure of the average change over time in the prices paid by urban consumers for a variety of consumer goods and services. The CPI is based on the experience of an average household, not on any specific family or individual, and varies by region. The CPI cannot be used as a measure of the change in pollution control equipment costs because changes in these costs are beyond the defined scope of the CPI. The CPI would not include the cost of SCR, for example, since the average household would not purchase $NO_x$ control equipment. In addition, it is not appropriate to adjust the commission's cost estimates based on the CPI because inflation is not uniform across all categories of goods and services. In other words, the CPI cannot be used to accurately determine the price change for an individual item. For example, over the past 20-plus years gasoline prices have increased at a lower rate than the rate that would be expected if one used the CPI. Thus, the gasoline available for $1.299 per gallon today is cheaper than gasoline which cost $.999 per gallon in 1979. Gasoline prices have varied widely since 1990, both increasing and decreasing. Prices have fallen since 1990 in some categories, particularly electronics. For example, computer prices have decreased dramatically over the past 20 years, even as computer capabilities and features have expanded.

As noted earlier, the commission used the most recently available data and cited the source of the data. 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. McAngus may be correct that the cost in the Chapter 117 rule proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275) 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, previous BCCA gas 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 preheat ammonia injection air, thereby lowering the power requirements of the ammonia injection system.

McAngus testified that he does not believe that the cap and trade market will develop because, based on his conversations with companies, "no one expects to be able to overcontrol," and any companies that generate credits have "indicated that they're going to keep them for themselves for a margin of error." McAngus testified that the credits will "be too valuable to the company for them to sell" to someone else. Deason testified that ExxonMobil does not expect to have any excess credits from overcontrol.

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 in 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 existing ESADs and further details of the technical feasibility of the ESADs can be found elsewhere in this preamble and in the preamble to the adoption of the existing ESADs on December 6, 2000 (see the January 12, 2001 issue of the *Texas Register* (26 TexReg 524)). 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 contemplated in the preamble to the Chapter 117 proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275). Although the number of SCRs is expected to be unprecedented, the ultimate number installed is almost 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 existing rules gives 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.

Smith testified that "there will be no surplus in the point source sectors in which one could trade off and hence obtain permits for expansion or for new plants." Smith suggested that one of the most significant impacts of the attainment demonstration SIP on the Houston economy will be the inability of the petrochemical and refining industries to grow. In his testimony, Smith also acknowledged that the BCCA report which he co-authored concluded that the HGA SIP rules merely slow, but do not stop, the continued growth of the Houston economy as a whole.

The mass emissions cap and trade program will cap the level of $NO_x$ emitted from stationary sources in HGA, 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 the new source's 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 commission agrees with Smith that the HGA SIP rules will permit the continued growth of the Houston economy and notes that under the mass emissions cap and trade program, overcontrol on some units will result in credits which can be used to enable the operation of new sources or expansion of existing sources.

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 Chapter 117 rule proposal published in the August 25, 2000 issue of the *Texas Register* (25 TexReg 8275), 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 existing ESADs. This demonstrates that the commission has sought to accomplish its duty.

Smith testified that cost effectiveness should always be calculated at the margin (i.e., the cost per ton for the last ton of emissions reduced), as opposed to calculating average cost per ton of emissions reduced.

The commission disagrees with Smith. Typically, both the EPA and the commission report the average cost per ton of emissions reduced for specific air regulations. This standard of measurement is reasonable when looking at the overall impacts of a regulation. However, the commission agrees that the cost per ton for the last ton of emissions reduced may provide useful information for decision-making where one is considering the merits of different regulatory strategies. Generally, it depends on the context of the analysis as to which type of data may be the most meaningful. To make a blanket statement that one measure should always be used in all contexts is perhaps an overstatement of fact. Economists use a marginal approach to find optimal choices or solutions. Smith's statement may be based upon his opinion that the approach used by economists leads to an economically efficient outcome. For the economist, stating that the marginal cost per ton of emissions reduced is equivalent to the marginal benefits per ton of emissions reduced for a particular rule is essentially stating that the optimal outcome is achieved or the most economically efficient regulatory alternative is chosen.

TxDOT stated that it is possible, although not typical, that situations would arise which would require a contractor to use a stationary diesel generator to provide electricity for hot mix and concrete batch plant operations in HGA, and that in these cases the higher costs would be passed along to TxDOT in the form of higher bid prices.

While it is possible that there may be affected stationary diesel engines at hot mix asphalt and concrete plants, these plants are typically located with access to the electrical grid, particularly if they will be at a site for more than one year. Those few that are located on sites without access to the grid must be on site for a full year to be considered stationary. For a long- term construction project requiring multiple years at a single site, the commission expects that competitive bidding will ensure that higher costs do not result. For example, a contractor that obtains a site with access to the grid presumably would be able to enter a more favorable bid than a contractor without such a site.

## SUBCHAPTER A. DEFINITIONS

### 30 TAC §117.10

STATUTORY AUTHORITY

The amendment is 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; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, which provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendment is also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §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; §382.051(d), concerning Permitting Authority of Commission; 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; and FCAA, 42 USC, §§7401 et seq.

*§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. Additional definitions for terms used in this chapter are found in §101.1 and §3.2 of this title (relating to Definitions).

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

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

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

(A) for the purposes of Subchapter B, Division 1 of this chapter (relating to Utility Electric Generation in Ozone Nonattainment Areas), all boilers, auxiliary steam boilers, and stationary gas turbines (including duct burners used in turbine exhaust ducts) 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; or

*(iii)* Houston/Galveston;

(B) for the purposes of Subchapter B, Division 2 of this chapter (relating to Utility Electric Generation in East and Central Texas), 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; or

(C) for the purposes of Subchapter B, Division 3 of this chapter (relating to Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas), all units in the Houston/Galveston ozone nonattainment area that generate electricity but do not meet the conditions specified in subparagraph (A) of this paragraph, including, but not limited to, cogeneration units and units owned by independent power producers.

(14) Emergency situation--As follows.

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

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

*(ii)* the period of time during which an emergency notice, as defined in *ERCOT Protocols, Section 2: Definitions and Acronyms* (January 5, 2001), issued by the Electric Reliability Council of Texas, Inc. (ERCOT) as specified in *ERCOT Protocols, Section 5: Dispatch* (January 5, 2001), is applicable to the serving electric power generating system. The emergency situation is considered to end upon expiration of the emergency notice issued by ERCOT;

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

*(iv)* an unforeseen failure of natural gas service;

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

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

(B) An emergency situation does not include operation for purposes of supplying power for distribution to the electric grid, operation for training purposes, or other foreseeable events.

(15) 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.

(16) 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.

(17) 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.

(18) 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.

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

(20) 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).

(21) 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.

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

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

(24) 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.

(25) 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.

(26) 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.

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

(28) 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.

(29) 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.

(30) 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.

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

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

(33) 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.

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

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

(36) 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.

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

(38) 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.

(39) 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.

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

(41) 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.

(42) 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.

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

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

(45) 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.

(46) 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.

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

be used in lieu of maximum rated capacities for the purpose of calculating the system-wide emission rate.

(48) 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.

(49) 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.

(50) 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; or

(C) for the purposes of §117.475 of this title (relating to Emission Specifications) and each requirement of this chapter associated with §117.475 of this title, any boiler, process heater, stationary gas turbine (including any duct burner in the turbine exhaust duct), or stationary internal combustion engine, as defined in this section.

(51) 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.

(52) 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 September 28, 2001.

TRD-200105871
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 18, 2001
Proposal publication date: June 15, 2001
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, 117.106 - 117.110, 117.119

STATUTORY AUTHORITY

The amendments are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, 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, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §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; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; §382.051(d), concerning Permitting Authority of Commission; 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; and FCAA, 42 USC, §§7401 et seq.

*§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 Use of Emissions Credits for Compliance).

(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 in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; 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, 0.020; and

(B) coal-fired or oil-fired, 0.040;

(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 (including duct burners used in turbine exhaust ducts):

(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.

(5) if and to the extent supported by the commission's continuing scientific assessment of the causes of and possible solutions to the Houston/Galveston area's nonattainment status for ozone, the executive director determines that attainment can be reached with fewer $NO_x$ emission reductions from point sources concurrent with additional emission reduction strategies, then the executive director will develop proposed rulemaking and a proposed state implementation plan revision involving revisions to the emission specifications in paragraphs (1) - (4) of this subsection for consideration at a commission agenda no later than June 1, 2002. In the event that the total $NO_x$ emission reductions from utility and non-utility point sources required for attainment is determined to be 80% from the 1997 emissions inventory baseline, the revised specifications shall be the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications in the following subparagraphs. The commission reserves all rights to assign any additional $NO_x$ reduction benefits supported by the science evaluation to the relief of other control measures, including further $NO_x$ point source relief.

(A) utility boilers:

*(i)* gas-fired, 0.030;

*(ii)* coal-fired or oil-fired;

*(I)* wall-fired, 0.050; and

*(II)* tangential-fired, 0.045;

(B) auxiliary steam boilers, 0.030; and

(C) stationary gas turbines (including duct burners used in turbine exhaust ducts), 0.032.

(d) Related emissions. No person shall allow the discharge into the atmosphere from any unit subject to the $NO_x$ emission limits specified in subsections (a) - (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.

(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, the following requirements apply.

(A) For units which meet the definition of electric generating facility (EGF), the owner or operator must use both the 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. An owner or operator may use the alternative methods specified in §117.570 of this title for purposes of complying with §117.108 of this title.

(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.

*§117.107. Alternative System-wide Emission Specifications.*

(a) An owner or operator of any gaseous- or coal-fired utility boiler or stationary gas turbine may achieve compliance with the nitrogen oxides ($NO_x$) emission limits of §117.105 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) by achieving compliance with a system-wide emission limitation. Any owner or operator who elects to comply with system-wide emission limits shall reduce emissions of $NO_x$ from affected units so that, if all such units were operated at their maximum rated capacity, the system-wide emission rate from all units in the system as defined in §117.10(13)(A) of this title (relating to Definitions) would not exceed the system-wide emission limit as defined in §117.10 of this title.

(1) The following units shall comply with the individual emission specifications of §117.105 of this title and shall not be included in the system-wide emission specification:

(A) gas turbines used for peaking service subject to the emission limits of §117.105(g) of this title;

(B) auxiliary steam boilers subject to the emission limits of §117.105(a), (c), (d), or (e) of this title.

(2) Coal-fired utility boilers or steam generators shall have a separate system average under this section, limited to those units.

(3) Oil-fired utility boilers or steam generators shall have a separate system average under this section, limited to those units. The emission limit assigned to each oil-fired unit in the system shall not exceed 0.5 pound (lb) $NO_x$ per million British thermal units (MMBtu) based on a rolling 24-hour average.

(b) The owner or operator shall establish enforceable emission limits for each affected unit in the system calculated in accordance with the maximum rated capacity averaging in this section as follows:

(1) for each gas-fired unit in the system, in lb/MMBtu:

(A) on a rolling 24-hour averaging period; and

(B) on a rolling 30-day averaging period;

(2) for each coal-fired unit in the system, in lb/MMBtu on a rolling 24-hour averaging period;

(3) for stationary gas turbines, in the units of the appropriate emission limitation of §117.105 of this title; and

(4) for each fuel oil-fired unit in the system, in lb/MMBtu on a rolling 24-hour averaging period.

(c) An owner or operator of any gaseous and liquid fuel-fired utility boiler, steam generator, or gas turbine shall:

(1) comply with the assigned maximum allowable emission rates for gas fuel while firing natural gas only;

(2) comply with the assigned maximum allowable emission rate for liquid fuel while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing, 24-hour average, allowable emission limit and the assigned liquid-firing allowable emission limit while operating on liquid and gaseous fuel concurrently.

(d) Solely for purposes of calculating the system-wide emission limit, the allowable mass emission rate for each affected unit shall be calculated from the emission specifications of §117.105 of this title, as follows.

(1) The $NO_x$ emissions rate (in pounds per hour) for each affected utility boiler, steam generator, or auxiliary steam boiler is the product of its average activity level for fuel oil firing or maximum rated capacity for gas firing and its $NO_x$ emission specification of §117.105 of this title.

(2) The $NO_x$ emissions rate (in pounds per hour) for each affected stationary gas turbine is the product of the in-stack $NO_x$, the turbine manufacturer's rated exhaust flow rate (expressed in pounds per hour at megawatt (MW) rating and International Standards Organization (ISO) flow conditions), and $(46/28)(10^{-6})$;
Figure: 30 TAC §117.107(d)(2) (No change.)

*§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(13)(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.

*§117.109. System Cap Flexibility.*

An owner or operator of a source of nitrogen oxides ($NO_x$) who is participating in the system cap under §117.108 of this title (relating to System Cap) may exceed their system cap provided that the owner or operator is complying with the requirements of §117.570 of this title (relating to Use of Emissions Credits for Compliance) or Chapter 101, Subchapter H, Division 1, 4, or 5 of this title (relating to Emission Credit Banking and Trading; Discrete Emission Credit and Trading Program; and System Cap Trading).

*§117.119. 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 fuel burned; gross and net energy production in megawatt-hours (MW-hr); and the date, time, and duration of the event.

(b) Notification. The owner or operator of a unit subject to the emission specifications of this division (relating to Utility Electric Generation in Ozone Nonattainment Areas) shall submit notification to the appropriate regional office and any local air pollution control agency having jurisdiction as follows:

(1) verbal notification of the date of any initial demonstration of compliance testing conducted under §117.111 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) performance evaluation conducted under §117.113 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 Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction a copy of any initial demonstration of compliance testing conducted under §117.111 of this title or any CEMS or PEMS performance evaluation conducted under §117.113 of this title:

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

(2) not later than the appropriate compliance schedules specified in §117.510 of this title (relating to Compliance Schedule for Utility Electric Generation in Ozone Nonattainment Areas).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring system under §117.113 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission limitations in this division and the monitoring system performance. All reports 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 (CFR), Part 60, §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the unit operating time during the reporting period:

(A) for stationary gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.113 of this title, excess emissions are computed as each one-hour period during which the hourly steam-to-fuel or water-to-fuel ratio is less than the ratio determined to result in compliance during the initial demonstration of compliance test required by §117.111 of this title;

(B) for utility boilers complying with §117.108 of this title (relating to System 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 steam-to-fuel or water-to-fuel ratio monitoring system downtime for the reporting period is less than 5.0% of the total unit operating time for the reporting period, only a summary report form (as outlined in the latest edition of the commission's "Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports") shall be submitted, unless otherwise requested by the executive director. If the total duration of excess emissions for the reporting period is greater than or equal to 1.0% of the total operating time for the reporting period or the CEMS or steam-to-fuel or water-to-fuel ratio monitoring system downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report shall both be submitted.

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

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

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

(3) quantity and type of fuel burned;

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

(5) emission monitoring data, in accordance with §117.113 of this title, including:

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

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

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

(6) the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.111 of this title; and

(7) records of hours of operation.

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 September 28, 2001.

TRD-200105872
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 18, 2001
Proposal publication date: June 15, 2001
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 TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, which provides the commission the authority to adopt rules consistent with the policy and purposes of the TCAA. The amendment is also adopted under TCAA, §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §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; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; §382.051(d), concerning Permitting Authority of Commission; 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; and FCAA, 42 USC, §§7401 et seq.

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 September 28, 2001.

TRD-200105875
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 18, 2001
Proposal publication date: June 15, 2001
For further information, please call: (512) 239-0348

♦ ♦ ♦

## DIVISION 3. INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL COMBUSTION SOURCES IN OZONE NONATTAINMENT AREAS

## 30 TAC §§117.203, 117.206, 117.210, 117.213, 117.214, 117.219

STATUTORY AUTHORITY

The amendments are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, 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, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §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; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; §382.051(d), concerning Permitting Authority of Commission; 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; and FCAA, 42 USC, §§7401 et seq.

*§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 §§117.206(i), 117.209(c)(1), 117.213(i), 117.214(a)(2), 117.216(a)(5), and 117.219(f)(6) of this title (relating to Emission Specifications for Attainment Demonstrations; Initial Control Plan Procedures; Continuous Demonstration of Compliance; Emission Testing and Monitoring for the Houston/Galveston Attainment Demonstration; Final Control Plan Procedures for Attainment Demonstration Emission Specifications; and Notification, Recordkeeping, and Reporting Requirements), 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 used as follows:

(A) in research and testing;

(B) for purposes of performance verification and testing;

(C) solely to power other engines or gas turbines during start-ups;

(D) exclusively in emergency situations, except that operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after October 1, 2001 in the Houston/Galveston ozone nonattainment area is ineligible for this exemption. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations (CFR) §60.15 (effective December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account;

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

(F) directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals; or

(G) as chemical processing gas turbines;

(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;

(10) any stationary diesel engine in the Beaumont/Port Arthur or Dallas/Fort Worth ozone nonattainment area;

(11) any stationary diesel engine placed into service before October 1, 2001 in the Houston/Galveston ozone nonattainment area which:

(A) operates less than 100 hours per year, based on a rolling 12-month average; and

(B) has not been modified, reconstructed, or relocated on or after October 1, 2001. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

(12) any new, modified, reconstructed, or relocated stationary diesel engine placed into service in the Houston/Galveston ozone nonattainment area on or after October 1, 2001 which:

(A) operates less than 100 hours per year, based on a rolling 12-month average, in other than emergency situations; and

(B) meets the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 (effective October 23, 1998) and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this paragraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account.

(b) The exemptions in subsection (a)(1), (2), (7), and (8)(A) of this section 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.

*§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 British thermal units per hour (MMBtu/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 in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the following emission specifications:

(1) gas-fired boilers:

(A) with a maximum rated capacity equal to or greater than 100 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. To ensure that this emission specification will result in a real 90% reduction in actual emissions, a consistent methodology shall be used to calculate the 90% reduction; 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. To ensure that this emission specification will result in a real 80% reduction in actual emissions, a consistent methodology shall be used to calculate the 80% reduction;

(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:

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

*(ii)* all others, 0.17 g $NO_x$/hp-hr;

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

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

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

(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; and

(D) diesel engines, excluding dual-fuel engines:

*(i)* placed into service before October 1, 2001 which have not been modified, reconstructed, or relocated on or after October 1, 2001, 11.0 g $NO_x$/hp-hr. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account; and

*(ii)* for engines not subject to clause (i) of this subparagraph:

*(I)* with a horsepower rating of less than 11 hp which are installed, modified, reconstructed, or relocated:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

*(IX)* with a horsepower rating of 750 hp or greater which are installed, modified, reconstructed, or relocated:

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

(-b-) on or after October 1, 2005, 4.5 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. To ensure that this emission specification will result in a real 80% reduction in actual emissions, a consistent methodology shall be used to calculate the 80% reduction; or

(B) 0.030 lb $NO_x$ per MMBtu;

(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; and

(18) if and to the extent supported by the commission's continuing scientific assessment of the causes of and possible solutions to the Houston/Galveston area's nonattainment status for ozone, the executive director determines that attainment can be reached with fewer $NO_x$ emission reductions from point sources concurrent with additional emission reduction strategies, then the executive director will develop proposed rulemaking and a proposed state implementation plan revision involving revisions to the emission specifications in paragraphs (1) - (17) of this subsection for consideration at a commission agenda no later than June 1, 2002. In the event that the total $NO_x$ emission reductions from utility and non-utility point sources required for attainment is determined to be 80% from the 1997 emissions inventory baseline, the revised specifications shall be the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications in the following subparagraphs. The commission reserves all rights to assign any additional $NO_x$ reduction benefits supported by the science evaluation to the relief of other control measures, including further $NO_x$ point source relief.

(A) gas-fired boilers:

*(i)* with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.020 lb $NO_x$ per MMBtu;

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

*(iii)* 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);

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

*(i)* 40 ppmv $NO_x$ at 0.0% $O_2$, dry basis;

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

*(iii)* alternatively, for units which did not use a CEMS or 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 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;

(C) BIF units which were regulated as existing facilities by the EPA at 40 CFR Part 266, Subpart H (as was in effect on June 9, 1993):

*(i)* with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.015 lb $NO_x$ per MMBtu; and

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

*(I)* 0.030 lb $NO_x$ per MMBtu; or

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

(D) coke-fired boilers, 0.057 lb $NO_x$ per MMBtu;

(E) wood fuel-fired boilers, 0.060 lb $NO_x$ per MMBtu;

(F) rice hull-fired boilers, 0.089 lb $NO_x$ per MMBtu;

(G) liquid-fired boilers, 2.0 lb $NO_x$ per 1,000 gallons of liquid burned;

(H) process heaters:

*(i)* other than pyrolysis reactors:

*(I)* with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.025 lb $NO_x$ per MMBtu;

*(II)* with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.025 lb $NO_x$ per MMBtu; and

*(III)* with a maximum rated capacity less than 40 MMBtu/hr, 0.036 lb $NO_x$ per MMBtu; and

*(ii)* pyrolysis reactors, 0.036 lb $NO_x$ per MMBtu;

(I) stationary, reciprocating internal combustion engines:

*(i)* gas-fired rich-burn engines:

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

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

*(ii)* gas-fired lean-burn engines, except as specified in clause (iii) of this subparagraph:

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

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

*(iii)* 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; and

*(iv)* diesel engines, excluding dual-fuel engines, as specified in paragraph (9)(D) of this subsection;

(J) stationary gas turbines:

*(i)* rated at 10 MW or greater, 0.032 lb $NO_x$ per MMBtu;

*(ii)* rated at 1.0 MW or greater, but less than 10 MW, 0.15 lb $NO_x$ per MMBtu; and

*(iii)* rated at less than 1.0 MW, 0.26 lb $NO_x$ per MMBtu;

(K) duct burners used in turbine exhaust ducts, the corresponding gas turbine emission limitation of subparagraph (J) of this paragraph;

(L) pulping liquor recovery furnaces, either:

*(i)* 0.050 lb $NO_x$ per MMBtu; or

*(ii)* 1.08 lb $NO_x$ per ADTP;

(M) kilns:

*(i)* lime kilns, 0.66 lb $NO_x$ per ton of CaO; and

*(ii)* lightweight aggregate kilns, 0.76 lb $NO_x$ per ton of product;

(N) metallurgical furnaces:

*(i)* heat treating furnaces, 0.087 lb $NO_x$ per MMBtu; and

*(ii)* reheat furnaces, 0.062 lb $NO_x$ per MMBtu;

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

(P) incinerators, either of the following:

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

*(ii)* 0.030 lb $NO_x$ per MMBtu; and

(Q) as an alternative to the emission specifications in subparagraphs (A) - (P) of this paragraph 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 Use of Emissions Credits for Compliance).

(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. An owner or operator may use the alternative methods specified in §117.570 of this title for purposes of complying with §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) and (9) of this title.

(h) Prohibition of circumvention. In the Houston/Galveston ozone nonattainment area:

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

(A) the greater of the following:

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

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

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

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

(3) the owner or operator of a unit subject to an emission specification in subsection (c) of this section which, as of December 31, 2000, combusts one or more fuel or waste streams containing chemical-bound nitrogen shall not re-direct these streams to flares or other units which are not subject to an emission specification in subsection (c) of this section.

(i) Operating restrictions. In the Houston/Galveston ozone nonattainment area, no person shall start or operate any stationary diesel or dual-fuel engine for testing or maintenance between the hours of 6:00 a.m. and noon, except:

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

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

*§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. Each EGF in the system cap shall be subject to the daily cap and appropriate 30-day cap of this section at all times. 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. Alternatively, an EGF that generates electricity primarily for internal use, but that during 1997 and all subsequent calendar years transferred (or will transfer) that generated electricity to a utility power distribution system at a rate less than 3.85% of its actual electrical generation is not subject to the requirements of this section.

(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 applicable during the months of July, August, and September shall be calculated using the following equation.
Figure: 30 TAC §117.210(c)(1)

(2) A rolling 30-day average emission cap applicable during all months other than July, August, and September shall be calculated using the following equation.
Figure: 30 TAC §117.210(c)(2)

(3) A maximum daily cap shall be calculated using the following equation.
Figure: 30 TAC §117.210(c)(3)

(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 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 (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;

(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; and

(I) fluid catalytic cracking units (including carbon monoxide (CO) boilers, CO furnaces, and catalyst regenerator vents).

(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 exemption of §117.205(h)(2) or §117.203(a)(6)(D), (11), or (12) of this title shall record the operating time with an elapsed run time meter. Any run time meter installed on or after October 1, 2001 shall be non-resettable.

(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 under §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.

(1) 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.

(A) The nitrogen oxides ($NO_x$) monitoring requirements of §117.213(c), (e), and (f) of this title (relating to Continuous Demonstration of Compliance) apply.

(B) The carbon monoxide (CO) monitoring requirements of §117.213(d) of this title apply.

(C) The totalizing fuel flow meter requirements of §117.213(a) of this title apply.

(D) 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).

(2) The owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.203(a)(6)(D), (11), or (12) of this title (relating to Exemptions) shall comply with the run time meter requirements of §117.213(i) of this title.

(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.

*§117.219. 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 appropriate regional office and any local air pollution control agency having jurisdiction 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 Office of Compliance and Enforcement, 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 richburn 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 exemption of §117.205(h)(2) or §117.203(a)(6)(D), (11), or (12) of this title (relating to Exemptions), 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. In addition, for each engine claimed exempt under §117.203(a)(6)(D) of this title, written records shall be maintained of the purpose of engine operation and, if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation;

(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;

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

(10) for each stationary diesel or dual-fuel engine in the Houston/Galveston ozone nonattainment area, records of each time the engine is operated for testing and maintenance, including:

(A) date(s) of operation;

(B) start and end times of operation;

(C) identification of the engine; and

(D) total hours of operation for each month and for the most recent 12 consecutive months.

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 September 28, 2001.

TRD-200105873
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 18, 2001
Proposal publication date: June 15, 2001
For further information, please call: (512) 239-0348

♦ ♦ ♦

## SUBCHAPTER D. SMALL COMBUSTION SOURCES
## DIVISION 2. BOILERS, PROCESS HEATERS, AND STATIONARY ENGINES AND GAS TURBINES AT MINOR SOURCES

**30 TAC §§117.471, 117.473, 117.475, 117.478, 117.479**

STATUTORY AUTHORITY

The amendments are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, 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, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §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; §382.051(d), concerning Permitting Authority of Commission; 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; and FCAA, 42 USC, §§7401 et seq.

*§117.473. Exemptions.*

(a) This division (relating to Boilers, Process Heaters, and Stationary Engines and Gas Turbines at Minor Sources) does not apply to the following, except as may be specified in §117.478(c) and §117.479(h) - (j) of this title (relating to Operating Requirements; and Monitoring, Recordkeeping, and Reporting Requirements):

(1) boilers and process heaters with a maximum rated capacity of 2.0 million British thermal units per hour (MMBtu/hr) or less;

(2) the following stationary engines:

(A) engines with a horsepower (hp) rating of less than 50 hp;

(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 in emergency situations, except that operation for testing or maintenance purposes is allowed for up to 52 hours per year, based on a rolling 12-month average. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after October 1, 2001 is ineligible for this exemption. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations (CFR) §60.15 (effective December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account;

(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) diesel engines placed into service before October 1, 2001 which:

*(i)* operate less than 100 hours per year, based on a rolling 12-month average; and

*(ii)* have not been modified, reconstructed, or relocated on or after October 1, 2001. For the purposes of this clause, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

(I) new, modified, reconstructed, or relocated stationary diesel engines placed into service on or after October 1, 2001 which:

*(i)* operate less than 100 hours per year, based on a rolling 12-month average, in other than emergency situations; and

*(ii)* meet the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 (effective October 23, 1998) and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (effective December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

(3) stationary gas turbines rated at less than 1.0 megawatt with initial start of operation on or before October 1, 2001.

(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.

*§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 in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications in subsection (c) of this section. The averaging time 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 in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001 for which the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the emission specifications in subsection (c) of this section. The averaging time shall be as follows:

(1) if the unit is operated with a $NO_x$ continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.479(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) The following $NO_x$ emission specifications shall be used in conjunction with subsection (a) of this section to determine allocations for Chapter 101, Subchapter H, Division 3 of this title, or in conjunction with subsection (b) of this section to establish unit-by-unit emission specifications, as appropriate:

(1) from boilers and process heaters, 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:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(6) as an alternative to the emission specifications in paragraphs (1) - (5) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu heat input.

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

(1) the greater of the following:

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

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

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

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

(f) The owner or operator of a unit subject to an emission specification in subsection (c) of this section which, as of December 31, 2000, combusts one or more fuel or waste streams containing chemical-bound nitrogen shall not re-direct these streams to flares or other units which are not subject to an emission specification in subsection (c) of this section.

*§117.478. Operating Requirements.*

(a) The owner or operator shall operate any unit subject to the emission limitations of §117.475 of this title (relating to Emission Specifications) in compliance with those limitations.

(b) All units 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 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.

(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.

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

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

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

*§117.479. Monitoring, Recordkeeping, and Reporting Requirements.*

(a) Totalizing fuel flow meters.

(1) The owner or operator of each unit 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 and Gas Turbines at Minor Sources).

(e) Testing requirements. The owner or operator of any unit subject to the emission limitations of §117.475 of this title shall comply with the following testing requirements.

(1) Each unit shall be tested for $NO_x$, carbon monoxide (CO), and $O_2$ emissions.

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

(3) 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 units 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 units 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 claimed exempt under §117.473(a)(2)(E), (H), or (I) of this title (relating to Exemptions) or §117.478(b)(5) of this title. In addition, for each engine claimed exempt under §117.473(a)(2)(E) of this title, written records shall be maintained of the purpose of engine operation and, if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation. The records shall be maintained for at least five years and shall be made available upon request to representatives of the executive director, EPA, or any local air pollution control agency having jurisdiction.

(i) Run time meters. The owner or operator of any stationary diesel engine claimed exempt using the exemption of §117.473(a)(2)(E), (H), or (I) of this title shall record the operating time with an elapsed run time meter. Any run time meter installed on or after October 1, 2001 shall be non- resettable.

(j) Records of operation for testing and maintenance. The owner or operator of each stationary diesel or dual-fuel engine shall maintain the following records for at least five years and make them available upon request by authorized representatives of the executive director, EPA, or local air pollution control agencies having jurisdiction:

(1) date(s) of operation;

(2) start and end times of operation;

(3) identification of the engine; and

(4) total hours of operation for each month and for the most recent 12 consecutive months.

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 September 28, 2001.

TRD-200105874
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 18, 2001
Proposal publication date: June 15, 2001
For further information, please call: (512) 239-0348

♦ ♦ ♦

## SUBCHAPTER E. ADMINISTRATIVE PROVISIONS

### 30 TAC §§117.510, 117.520, 117.534, 117.570

STATUTORY AUTHORITY

The amendments are adopted under TWC, §5.103, which provides the commission the authority to adopt rules necessary to carry out its powers and duties under the TWC; and under Texas Health and Safety Code, TCAA, §382.017, concerning Rules, 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, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §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; §382.051(d), concerning Permitting Authority of Commission; 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; and FCAA, 42 USC, §§7401 et seq.

*§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 under 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)* §117.108 of this title (relating to System Cap); or

*(II)* §117.570 of this title (relating to Use of Emissions Credits for Compliance);

(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-) §117.108 of this title; or

(-b-) §117.570 of this title;

*(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 under 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)* March 31, 2005, install any totalizing fuel flow meters and emissions monitors required by §117.114 of this title, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of $NO_x$) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.114 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit; 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 in accordance with §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:

*(i)* no later than June 30, 2001, submit to the executive director the certification of level of activity, $H_i$, specified in §117.108 of this title for electric generating facilities (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 §117.108 of this title for EGFs which were not in operation prior to January 1, 1997; and

*(iii)* 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 47% 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

*(II)* March 31, 2004, demonstrate that at least 95% 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.

(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 in accordance with §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.

(D) 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.

(E) If alternate emission specifications are implemented under §117.106(c)(5) of this title, the owner or operator of each EGF 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 50% 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

*(ii)* March 31, 2004, demonstrate compliance with the system cap limit of §117.108 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 Use of Emissions Credits for Compliance);

(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 subparagraph (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)* March 31, 2005, install any totalizing fuel flow meters, run time meters, and emissions monitors required by §117.214 of this title, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of $NO_x$) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.214 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit; 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 in accordance with §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 or 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 compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of $NO_x$) is installed on or before March 31, 2004, submit a demonstration of the $NO_x$ emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup $NO_x$ emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2004, were not equipped with flue gas cleanup, shall form the April 1, 2004 - March 31, 2005 system cap limit of §117.210 of this title;

*(II)* March 31, 2005, demonstrate compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of $NO_x$) is installed on or before March 31, 2005, submit a demonstration of the $NO_x$ emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup $NO_x$ emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2005, were not equipped with flue gas cleanup, shall form the April 1, 2005 - March 31, 2006 system cap limit of §117.210 of this title;

*(III)* March 31, 2006, demonstrate compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of $NO_x$) is installed on or before March 31, 2006, submit a demonstration of the $NO_x$ emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup $NO_x$ emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2006, were not equipped with flue gas cleanup, shall form the April 1, 2006 - March 31, 2007 system cap limit of §117.210 of this title; and

*(IV)* March 31, 2007, demonstrate compliance with the system cap of §117.210 of this title.

(C) If alternative emission specifications are implemented under §117.206(c)(18) of this title, the owner or operator of each EGF shall:

*(i)* perform stack tests conducted in accordance with §117.211 of this title; or, as applicable,

*(ii)* conduct 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

*(iii)* comply with the requirements of §117.210 of this title as soon as practicable, but no later than:

*(I)* March 31, 2004, demonstrate compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of $NO_x$) is installed on or before March 31, 2004, submit a demonstration of the $NO_x$ emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup $NO_x$ emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2004, were not equipped with flue gas cleanup, shall form the April 1, 2004 - March 31, 2005 system cap limit of §117.210 of this title;

*(II)* March 31, 2005, demonstrate compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of $NO_x$) is installed on or before March 31, 2005, submit a demonstration of the $NO_x$ emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup $NO_x$ emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2005, were not equipped with flue gas cleanup, shall form the April 1, 2005 - March 31, 2006 system cap limit of §117.210 of this title;

*(III)* March 31, 2006, demonstrate compliance with the system cap limit of §117.210 of this title as follows:

(-a-) for those EGFs for which flue gas cleanup (for example, controls which use a chemical reagent for reduction of $NO_x$) is installed on or before March 31, 2006, submit a demonstration of the $NO_x$ emission reductions that have been accomplished; and

(-b-) the completed flue gas cleanup $NO_x$ emission reduction demonstration, plus the highest 30-day average emissions measured in the 1997 - 1999 period for EGFs which, as of March 31, 2006, were not equipped with flue gas cleanup, shall form the April 1, 2006 - March 31, 2007 system cap limit of §117.210 of this title; and

*(IV)* March 31, 2007, demonstrate compliance with the system cap of §117.210 of this title.

(D) 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 in accordance with §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.

(E) 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.

(F) For diesel and dual-fuel engines, the owner or operator shall comply with the restriction on hours of operation for maintenance or testing, and associated recordkeeping, as soon as practicable, but no later than April 1, 2002.

*§117.534. Compliance Schedule for Boilers, Process Heaters, and Stationary Engines and Gas Turbines 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 and Gas Turbines 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 and run time meters required by §117.479 of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements) and begin keeping records of fuel usage no later than March 31, 2005, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of $NO_x$) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.479 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit;

(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 in accordance with §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 in accordance with §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;

(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; and

(E) for diesel and dual-fuel engines, comply with the restriction on hours of operation for maintenance or testing, and associated recordkeeping, as soon as practicable, but no later than April 1, 2002.

(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 and run time meters required by §117.479 of this title and begin keeping records of fuel usage no later than March 31, 2005, except that if flue gas cleanup (for example, controls which use a chemical reagent for reduction of $NO_x$) is installed on a unit before March 31, 2005, then the emissions monitors required by §117.479 of this title must be installed and operated at the time of startup following the installation of flue gas cleanup on that unit;

(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 in accordance with §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;

(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; and

(D) for diesel and dual-fuel engines, comply with the restriction on hours of operation for maintenance or testing, and associated recordkeeping, as soon as practicable, but no later than April 1, 2002.

*§117.570. Use of Emissions Credits for Compliance.*

(a) An owner or operator of a unit not subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) may meet emission control requirements of §117.105 or §117.205 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), §117.106 or §117.206 of this title (relating to Emission Specifications for Attainment Demonstrations), §117.107 of this title (relating to Alternative System-wide Emission Specifications), §117.207 of this title (relating to Alternative Plant-wide Emission Specifications), §117.223 of this title (relating to Source Cap), or §117.475 of this title (relating to Emission Specifications) in whole or in part, by obtaining an emission reduction credit (ERC), mobile emission reduction credit (MERC), discrete emission reduction credit (DERC), or mobile discrete emission reduction credit (MDERC) in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title (relating to Emission Credit Banking and Trading; and Discrete Emission Credit Banking and Trading), unless there are federal or state regulations or permits under the same commission account number which contain a condition or conditions precluding such use.

(b) An owner or operator of a unit subject to §§117.108, 117.138, or 117.210 of this title (relating to System Cap) may meet the emission control requirements of these sections in whole or in part, by complying with the requirements of Chapter 101, Subchapter H, Division 5 of this title (relating to System Cap Trading) or by obtaining an ERC, MERC, DERC, or MDERC in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title, unless there are federal or state regulations or permits under the same commission account number which contain a condition or conditions precluding such use.

(c) For the purposes of this section, the term "reduction credit (RC)" refers to an ERC, MERC, DERC, or MDERC, whichever is applicable.

(d) Any lower $NO_x$ emission specification established under this chapter for the unit or units using RCs shall require the user of the RCs to obtain additional RCs in accordance with Chapter 101, Subchapter H, Division 1 or 4 of this title and/or otherwise reduce emissions prior to the effective date of such rule change. For units using RCs in accordance with this section which are subject to new, more stringent rule limitations, the owner or operator using the RCs shall submit a revised final control plan to the executive director in accordance with §117.117 or §117.217 of this title (relating to Revision of Final Control Plan) to revise the basis for compliance with the emission specifications of this chapter. The owner or operator using the RCs shall submit the revised final control plan as soon as practicable, but no later than 90 days prior to the effective date of the new, more stringent rule. The owner or operator of the unit(s) currently using RCs shall calculate the necessary emission reductions per unit as follows.
Figure: 30 TAC §117.570(d)

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 September 28, 2001.

TRD-200105876
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: October 18, 2001
Proposal publication date: June 15, 2001
For further information, please call: (512) 239-0348

♦ ♦ ♦

# TITLE 31. NATURAL RESOURCES AND CONSERVATION

## PART 2. TEXAS PARKS AND WILDLIFE DEPARTMENT

### CHAPTER 65. WILDLIFE
### SUBCHAPTER D. DEER MANAGEMENT PERMIT

**31 TAC §65.132, §65.136**

The Texas Parks and Wildlife Commission adopts amendments to §65.132 and §65.136, concerning Deer Management Permit, without changes to the proposed text as published in the July 27, 2001, issue of the *Texas Register* (26 TexReg 5608) and will not be republished.

The amendment to §65.132 is necessary to establish an explicit period of validity for permits, and to give the department the ability, by increasing the number of employees authorized to approve permit applications, to avoid potential administrative bottlenecks with respect to the application and approval process. The amendment to §65.136 is necessary to ensure that deer held under a deer management permit are not subject to trapping activities under a permit to Trap, Transport, and Transplant Game Animals and Game Birds (Triple T permit). The department's trapping period for Triple T deer ends March 31. The amendment is intended to prevent the deer management permit from being used simply as a method for producing deer for relocation.

The amendment to §65.132, concerning Permit Application and Fees, establishes a one-year period of validity for permits issued under the subchapter and allows more department employees to approve deer management plans. The amendment to §65.136, concerning Release, alters the current requirement that deer held under a deer management permit be released no earlier than March 1 and replaces that date with April 1.

One commenter opposed adoption of the proposed rules. The commenter stated that decision-making regarding permit approval was being entrusted to lower level employees when the decisions should be made at the executive level. The commenter further stated that the provision in proposed §65.132(a) that 'no DMP may be issued' should read 'no DMP shall be issued,' because the proposed language is permissive rather than restrictive. Finally, the commenter stated that the release provisions of §65.136 were a sham, in that deer are liberated from a small enclosure into an area surrounded by a high fence, which is not liberation at all. The department disagrees with the commenter and responds as follows. The functional title of an employee authorized to approve a permit application is immaterial; employees with the requisite technical and professional ability and experience to author wildlife management plans can be assumed to be proficient in the skills necessary to evaluate and approve permit applications. The use of 'may' rather than shall' in §65.132(a) is not ambiguous. The sense of the sentence is that a permit will not be issued unless and until a deer management plan has been approved. Finally, owing to the fact that Parks and Wildlife Code, Chapter 43, Subchapter R explicitly requires a property to be surrounded by a high fence as a condition of permit issuance, the release provisions of §65.136 are consistent with legislative intent. No changes were made as a result of the comments.

Texas Wildlife Association supported adoption of the proposed rules.

The rules are adopted under Parks and Wildlife Code, §43.603, which authorizes the commission to establish conditions governing a permit issued under Parks and Wildlife Code, Chapter 43, Subchapter R.

The adopted rules affect Parks and Wildlife Code, Chapter 43, Subchapter R.

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 September 28, 2001.

TRD-200105882
Gene McCarty
Chief of Staff
Texas Parks and Wildlife Department
Effective date: October 18, 2001
Proposal publication date: July 27, 2001
For further information, please call: (512) 389-4775

♦ ♦ ♦

## SUBCHAPTER N. MIGRATORY GAME BIRD PROCLAMATION

### 31 TAC §§65.314, 65.317, 65.318, 65.320, 65.321

The Texas Parks and Wildlife Commission adopts amendments to §§65.314, 65.317, 65.318, 65.320, and 65.321, concerning the Migratory Game Bird Proclamation. Sections 65.314, 65.317, 65.318, and 65.321 are adopted with changes to the proposed text as published in the April 27, 2001, issue of the *Texas Register* (26 TexReg 3141). Section 65.320 is adopted without change and will not be republished. The change to §65.314, concerning Zones and Boundaries for Early Season Species, removes subsection (e), which contains the zones and boundaries for sandhill cranes. The contents of subsection (e) are relocated in §65.317 as new subsection (c). The change to §65.317, concerning Zones and Boundaries for Late Season Species, reinstates the north duck zone boundaries from last year and adds new subsection (c), which contains the boundaries for sandhill crane zones. The change to §65.318, concerning Open Seasons and Bag Limits- Late Season Species, creates a restricted special season for the take of canvasback ducks, ends the season for Canada geese and brant in the Eastern Zone earlier than what was proposed, and establishes season lengths and bag limits for sandhill cranes by adding new paragraph (3). The change to §65.321, concerning Special Management Provisions, eliminates proposed early closures of open seasons for migratory game birds, and alters the opening of the conservation season for light geese in the western goose zone.

The amendments are necessary, generally, to create opportunity for the public to hunt migratory game birds and to discharge the department's obligation to provide for sound biological management of the state's wildlife resources. The amendment to §65.314, concerning Zones and Boundaries for Early Season Species, is specifically necessary to clearly delineate the areas of the state to which the various seasons and restrictions apply. The amendment to §65.317, concerning Zones and Boundaries for Late Season Species, is specifically necessary to clearly delineate the areas of the state to which the various seasons and restrictions apply. The amendment to §65.318, concerning Open Seasons and Bag and Possession Limits - Late Season Species, is specifically necessary to adjusts the season dates for late-season species of migratory game birds to account for calendar-shift, and to create season lengths compatible with frameworks issued by the U.S. Fish and Wildlife Service. The amendment to §65.321, concerning Special Management Provisions, is specifically necessary to create a Special Snow Goose Conservation Period to assist in managing the severe impact that the overpopulation of light geese is exerting on arctic and subarctic breeding grounds, threatening the long-term health of those species.

The amendment to §65.314, concerning Zones and Boundaries for Early Season Species, will function by removing the provisions concerning sandhill cranes so they can be relocated in another section. The amendment to §65.317, concerning Zones and Boundaries for Late Season Species, will function by altering the boundary of the North Duck Zone to create additional hunting opportunity in southeast Texas, by creating additional recreational opportunity by opening parts of the previously closed mid-and lower-Gulf coasts to sandhill crane hunting, and by adjusting the eastern boundary of crane Zone B to match the boundary of the Goose Zone to minimize impacts of the Light Goose Conservation Season. The amendment to §65.118, concerning Open Seasons and Bag and Possession Limits - Late Season Species, will function by adjusting the season dates and bag limits for late-season species of migratory game birds to account for calendar-shift and to comply with federal frameworks. The amendment to §65.320, concerning Extended Falconry Season--Late Season Species, will function by adjusting season dates for the take of late-season species of migratory game birds by means of falconry. The amendment to §65.321, concerning Special Management Provisions, will function by adjusting the dates for the Special Snow Goose Conservation Period to account for calendar shift, and by eliminating the provisions for early closure of other migratory game bird seasons.

The department received three comments opposed to the proposed alteration of duck zone boundaries. The department agrees with the comments and has made changes accordingly. The department received one comment in support of the proposed amendment.

The department received nine comments requesting that duck season begin later than proposed. The department disagrees with the comments and responds that the proposed opening day for duck season is selected on the basis of hunter preference. No changes were made as a result of the comments.

The department received four comments requesting that duck season not be a split season, as proposed. The department disagrees with the comments and responds that the configuration of duck season is based on hunter preference and the department's desire to provide opportunity at times when the most people are likely to be able to take advantage of it. No changes were made as a result of the comments.

The department received two comments requesting that the season for canvasback ducks be closed. The department disagrees with the comments and responds that federal frameworks are based on the biological status of migratory game bird populations. The U.S. Fish and Wildlife this year has created a shortened season for canvasbacks, which is designed to afford hunting opportunity without producing biological harm to the population. No changes were made as a result of the comments.

The department received one comment requesting that the Canada goose season not be shortened. The department agrees with the comment and responds that Canada goose season has not been shortened.

Texas Wildlife Association commented in favor of adoption of the proposed rules.

The amendments are adopted under Parks and Wildlife Code, Chapter 64, which authorizes the Commission and the Executive Director to provide the open season and means, methods, and devices for the hunting and possessing of migratory game birds.

*§65.314. Zones and Boundaries for Early Season Species*

(a) Rails: statewide.

(b) Mourning and white-winged doves.

(1) North Zone: That portion of the state north of a line beginning at the International Bridge south of Fort Hancock; thence north along FM 1088 to State Highway 20; thence west along State Highway 20 to State Highway 148; thence north along State Highway 148 to Interstate Highway 10 at Fort Hancock; thence east along Interstate Highway 10 to Interstate Highway 20; thence northeast along Interstate Highway 20 to Interstate Highway 30 at Fort Worth; thence northeast along Interstate Highway 30 to the Texas-Arkansas state line.

(2) Central Zone: That portion of the state between the North Zone and the South Zone.

(3) South Zone: That portion of the state south of a line beginning at the International Toll Bridge in Del Rio; thence northeast along U.S. Highway 277 Spur to U.S. Highway 90 in Del Rio; thence east along U.S. Highway 90 to Interstate Highway 10 at San Antonio; thence east along Interstate Highway 10 to the Texas-Louisiana State Line.

(4) Special white-winged dove area: That portion of the state south and west of a line beginning at the International Toll Bridge in Del Rio; thence northeast along U.S. Highway 277 Spur to U.S. Highway 90 in Del Rio; thence east along U.S. Highway 90 to United States Highway 83 at Uvalde; thence south along U.S. Highway 83 to State Highway 44; thence east along State Highway 44 to State Highway 16 at Freer; thence south along State Highway 16 to State Highway 285 at Hebbronville; thence east along State Highway 285 to FM 1017; thence southeast along FM 1017 to State Highway 186 at Linn; thence east along State Highway 186 to the Mansfield Channel at Port Mansfield; thence east along the Mansfield Channel to the Gulf of Mexico.

(c) Gallinules (Moorhen or common gallinule and purple gallinule): statewide.

(d) Teal ducks (blue-winged, green-winged, and cinnamon): statewide.

(e) Woodcock: statewide.

(f) Common snipe: statewide.

*§65.317. Zones and Boundaries for Late Season Species.*

(a) Ducks, mergansers, and coots.

(1) High Plains Mallard Management Unit: that portion of Texas lying west of a line from the international toll bridge at Del Rio, thence northward following U.S. Highway 277 to Abilene, State Highway 351 and State Highway 6 to Albany, and U.S. Highway 283 from Albany to Vernon, thence eastward along U.S. Highway 183 to the Texas-Oklahoma state line.

(2) North Zone: that portion of Texas not in the High Plains Mallard Management Unit but north of a line from the International Toll Bridge in Del Rio; thence northeast along U.S. Highway 277 Spur to U.S. Highway 90 in Del Rio; thence east along U.S. Highway 90 to Interstate Highway 10 at San Antonio; thence east along Interstate Highway 10 to the Texas-Louisiana State Line.

(3) South Zone: the remainder of the state.

(b) Geese.

(1) Western Zone: that portion of Texas lying west of a line from the international toll bridge at Laredo, thence northward following IH 35 and 35W to Fort Worth, thence northwest along U.S. Highways 81 and 287 to Bowie, thence northward along U.S. Highway 81 to the Texas-Oklahoma state line.

(2) Eastern Zone: the remainder of the state.

(c) Sandhill cranes.

(1) Zone A: that portion of Texas lying west of a line beginning at the international toll bridge at Laredo, thence northeast along U.S. Highway 81 to its junction with Interstate Highway 35 in Laredo, thence north along Interstate Highway 35 to its junction with Interstate Highway 10 in San Antonio, thence northwest along Interstate Highway 10 to its junction with U.S. Highway 83 at Junction, thence north along U.S. Highway 83 to its junction with U.S. Highway 62, 16 miles north of Childress, thence east along U.S. Highway 62 to the Texas-Oklahoma state line.

(2) Zone B: that portion of Texas lying within boundaries beginning at the junction of U.S. Highway 81 and the Texas-Oklahoma state line, thence southeast along U.S. Highway 81 to its junction with U.S. Highway 287 in Montague County, thence southeast along U.S. Highway 287 to its junction with Interstate Highway 35W in Fort Worth, thence southwest along Interstate Highway 35 to its junction with Interstate Highway 10 in San Antonio, thence northwest along Interstate Highway 10 to its junction with U.S. Highway 83 in Junction, thence north along U.S. Highway 83 to its junction with U.S. Highway 62, 16 miles north of Childress, thence east along U.S. Highway 62 to the Texas-Oklahoma state line, thence south along the Texas-Oklahoma state line to the south bank of the Red River, thence eastward along the vegetation line on the south bank of the Red River to U.S. Highway 81.

(3) Zone C: the remainder of the state, except for the closed areas specified in paragraph (4) of this subsection.

(4) closed areas:

(A) that portion of the state lying east and north of a line beginning at the junction of U.S. Highway 81 and the Texas-Oklahoma state line, thence southeast along U.S. Highway 81 to its junction with U.S. Highway 287 in Montague County, thence southeast along U.S. Highway 287 to its junction with Interstate Highway 35W in Fort Worth, thence southwest along Interstate Highway 35 to its junction with U.S. Highway 290 East in Austin, thence east along U.S. Highway 290 to its junction with Interstate Loop 610 in Harris County, thence south and east along Interstate Loop 610 to its junction with Interstate Highway 45 in Houston, thence south on Interstate Highway 45 to State Highway 342, thence to the shore of the Gulf of Mexico, and thence north and east along the shore of the Gulf of Mexico to the Texas-Louisiana state line.

(B) that portion of the state lying within the boundaries of a line beginning at the Kleberg-Nueces county line and the shore of the Gulf of Mexico, thence west along the county line to Park Road 22 in Nueces County, thence north and west along Park Road 22 to its junction with State Highway 358 in Corpus Christi, thence west and north along State Highway 358 to its junction with State Highway 286, thence north along State Highway 286 to its junction with Interstate Highway 37, thence east along Interstate Highway 37 to its junction with U.S. Highway 181, thence north and west along U.S. Highway 181 to its junction with U.S. Highway 77 in Sinton, thence north and east along U.S. Highway 77 to its junction with U.S. Highway 87 in Victoria, thence south and east along U.S. Highway 87 to its junction with State Highway 35 at Port Lavaca, thence north and east along State Highway 35 to the south end of the Lavaca Bay Causeway, thence south and east along the shore of Lavaca Bay to its junction with the Port Lavaca Ship Channel, thence south and east along the Lavaca Bay Ship Channel to the Gulf of Mexico, and thence south and west along the shore of the Gulf of Mexico to the Kleberg-Nueces county line.

*§65.318. Open Seasons and Bag and Possession Limits--Late Season.*

Except as specifically provided in this section, the possession limit for all species listed in this section shall be twice the daily bag limit.

(1) Ducks, mergansers, and coots. The daily bag limit for ducks is six, which may include no more than five mallards or Mexican mallards (Mexican duck), only two of which may be hens, three scaup, one mottled duck, one pintail, two redheads, one canvasback, and two wood ducks. The daily bag limit for coots is 15. The daily bag limit for mergansers is five, which may include no more than one hooded merganser. No person may take a canvasback duck except during the period from December 27, 2001 through January 20, 2002.

(A) High Plains Mallard Management Unit: October 20-22, 2001, and October 27, 2001-January 20, 2002.

(B) North Zone: October 27-28, 2001, and November 10, 2001-January 20, 2002.

(C) South Zone: October 27-November 25, 2001, and December 8, 2001-January 20, 2002.

(2) Geese.

(A) Western Zone.

*(i)* Light geese: October 27, 2001-February 10, 2002. The daily bag limit for light geese is 20, and there is no possession limit.

*(ii)* Dark geese: October 27, 2001-February 10, 2002. The daily bag limit for dark geese is five, which may not include more than one white-fronted goose.

(B) Eastern Zone.

*(i)* Light geese: October 27, 2001-January 20, 2002. The daily bag limit for light geese is 20, and there is no possession limit.

*(ii)* Dark geese:

*(I)* White-fronted geese: October 27, 2001-January 20, 2002. The daily bag limit for white-fronted geese is two.

*(II)* Canada geese and brant: October 27, 2001-January 20, 2002. The daily bag limit is one Canada goose or one brant.

(3) Sandhill cranes. A free permit is required of any person to hunt sandhill cranes in areas where an open season is provided under this proclamation. Permits will be issued on an impartial basis with no limitation on the number of permits that may be issued.

(A) Zone A: November 10, 2001-February 10, 2002. The daily bag limit is three. The possession limit is six.

(B) Zone B: December 1, 2001-February 10, 2002. The daily bag limit is three. The possession limit is six.

(C) Zone C: December 29, 2001-Janaury 20, 2002. The daily bag limit is two. The possession limit is four.

(4) Special Youth-Only Season. There shall be a special youth-only duck season during which the hunting, taking, and possession of ducks, mergansers, and coots is restricted to licensed hunters 15 years of age and younger accompanied by a person 18 years of age or older, except for persons hunting by means of falconry under the provisions of §65.320 of this chapter (relating to Extended Falconry Season--Late Season Species). Bag and possession limits in any given zone during the season established by this paragraph shall be as provided for that zone by paragraph (1) of this section. Season dates are as follows:

(A) High Plains Mallard Management Unit: October 13-14, 2001;

(B) North Zone: October 20-21, 2001; and

(C) South Zone: October 20-21, 2001.

*§65.321. Special Management Provisions.*

The provisions of paragraphs (1)-(3) of this section apply only to the hunting of light geese. All provisions of this subchapter continue in effect unless specifically provided otherwise in this section; however, where this section conflicts with the provisions of this subchapter, this section prevails.

(1) Means and methods. In addition to the means and methods authorized in §65.310(a) of this title (relating to Means , Methods, and Special Requirements), the following means and methods are lawful during the time periods set forth in paragraph (4) of this section:

(A) shotguns capable of holding more than three shells; and

(B) electronic calling devices.

(2) Possession. During the time periods set forth in paragraph (4) of this section:

(A) there shall be no bag or possession limits; and

(B) the provisions of §65.312 of this title (relating to Possession of Migratory Game Birds) do not apply; and

(C) a person may give, leave, receive, or possess legally taken light geese or their parts, provided the birds are accompanied by a wildlife resource document from the person who killed the birds. The wildlife resource document is not required if the possessor lawfully killed the birds; the birds are transferred at the personal residence of the donor or donee; or the possessor also possesses a valid hunting license, a valid waterfowl stamp, and is HIP certified. The wildlife resource document shall accompany the birds until the birds reach their final destination, and must contain the following information:

*(i)* the name, signature, address, and hunting license number of the person who killed the birds;

*(ii)* the name of the person receiving the birds;

*(iii)* the number and species of birds or parts;

*(iv)* the date the birds were killed; and

*(v)* the location where the birds were killed (e.g., name of ranch; area; lake, bay, or stream; county).

(3) Shooting hours. During the time periods set forth in paragraph (4) of this section, shooting hours are from one half-hour before sunrise until one half-hour after sunset.

(4) Special Light Goose Conservation Period.

(A) From January 21, 2002 through March 31, 2002, the take of light geese is lawful in the Eastern Zone as defined in §65.317 of this title (relating to Zones and Boundaries for Late Season Species).

(B) From February 11, 2002 through March 31, 2002, the take of light geese is lawful in the Western Zone as defined in §65.317 of this title (relating to Zones and Boundaries for Late Season Species).

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 September 28, 2001.

TRD-200105883
Gene McCarty
Chief of Staff
Texas Parks and Wildlife Department
Effective date: October 18, 2001
Proposal publication date: April 27, 2001
For further information, please call: (512) 389-4775

♦ ♦ ♦

# TITLE 34. PUBLIC FINANCE

# PART 1. COMPTROLLER OF PUBLIC ACCOUNTS

## CHAPTER 3. TAX ADMINISTRATION

## SUBCHAPTER J. PETROLEUM PRODUCTS DELIVERY FEE

### 34 TAC §3.151

The Comptroller of Public Accounts adopts an amendment to §3.151, concerning imposition, collection, and bond and other security of the fee, without changes to the proposed text as published in the August 10, 2001, issue of the *Texas Register* (26 TexReg 5988).

House Bills 2687 and 2912, 77th Legislature, 2001, amend Water Code, Chapter 26, to reduce the petroleum products delivery fee by 33%. Subsection (c), of the existing rule is amended to implement the reduced fee rate schedule for the fiscal years 2002 and 2003, effective September 1, 2001.

No comments were received regarding adoption of the amendment.

This amendment is adopted under Tax Code, §111.002, which provides the comptroller with the authority to prescribe, adopt, and enforce rules relating to the administration and enforcement of the provisions of Tax Code, Title 2.

The amendment implements Water Code, §26.3574.

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 September 27, 2001.

TRD-200105851
Martin Cherry
Deputy General Counsel for Tax Policy and Agency Affairs
Comptroller of Public Accounts
Effective date: October 17, 2001
Proposal publication date: August 10, 2001
For further information, please call: (512) 305-9881

♦ ♦ ♦

## SUBCHAPTER K. HOTEL OCCUPANCY TAX

### 34 TAC §3.163

The Comptroller of Public Accounts adopts an amendment to §3.163, concerning refund of hotel occupancy tax, with changes to the proposed text as published in the August 3, 2001 issue of the *Texas Register* (26 TexReg 5771).

The 77th Legislature, in House Bill 2914, amended the Tax Code, Chapter 156, to require state agencies to use a fiscal year quarter when requesting a refund of state hotel occupancy taxes. Subsection (b) is amended to change the period for which a refund may be requested from a calendar quarter to fiscal year quarter. The amendment clarifies the procedures agencies must follow to apply for refunds of municipal and county hotel taxes.

Subsection (b) of the proposed amendment has been changed to include information regarding the refund of state hotel tax to state agencies.

No comments were received concerning the proposed amendment.

This amendment is proposed under the Tax Code, §111.002, which provides the comptroller with the authority to prescribe, adopt, and enforce rules relating to the administration and enforcement of the provisions of the Tax Code, Title 2.

The amendment implements Tax Code, §156.154(c).

*§3.163. Refund of Hotel Occupancy Tax.*

(a) State agency. A state agency is an agency, institution, board, or commission of the State of Texas other than an institution of higher education as defined in Education Code, §61.003.

(b) Refunds. A state agency may request a refund for each fiscal year quarter for the state hotel tax paid directly to a hotel or the amount of state hotel tax for which the agency reimbursed a state employee on a state travel voucher. A state agency that uses the Uniform Statewide Accounting System (USAS) will receive its state hotel tax refund by way of USAS. A state agency must directly contact the applicable city or county to apply for a refund of municipal or county hotel tax for which the agency reimbursed a state employee

(c) Time limitation. A state agency may apply for a refund of state hotel tax no later than two years after the end of the fiscal year in which the travel occurred as provided by State of Texas Travel Allowance Guide, §1.17 and §8.06. A state agency may apply for a refund of municipal or county hotel occupancy tax for each calendar quarter according to the local city or county ordinance. In the absence of a local ordinance, the same time limitation that applies to the refund of state hotel tax will apply to municipal and county taxes.

(d) Documentation required.

(1) Documentation must be maintained to substantiate the claim, including a copy of the hotel folio, billing statement, invoice, or other document, that contains the following information:

(A) name of the hotel,

(B) location address of hotel,

(C) name of city where hotel is located,

(D) name of county where hotel is located,

(E) date(s) of lodging,

(F) amount of state, municipal, and county hotel tax paid separately stated,

(G) method of payment (travel voucher reimbursement, state credit card, state purchase order, direct billing, other), and

(H) name of employee, if tax reimbursed on travel voucher.

(2) A municipality or county may, by local ordinance, require additional documentation or require documentation be submitted with a claim for refund of local tax.

(e) Separate refund claim required. A separate refund claim form must be filed with each municipality or county.

(f) Form. Each claim for refund for state hotel occupancy tax must be filed on a form furnished by the comptroller. The municipal and county hotel occupancy tax refund claim form, herein adopted by reference, must be substantially in the form set out as follows. Copies of the certificate are available for inspection at the office of the Texas Register or may be obtained from the Comptroller of Public Accounts, P.O. Box 13528, Austin, Texas 78711. Copies may also be requested by calling our toll-free number 1-800-252-1385. In Austin, call 463-4600. From a Telecommunication Device for the Deaf (TDD) only, call 1-800-248-4099 toll free. In Austin the local TDD number is 463-4621

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 September 27, 2001.

TRD-200105850
Martin Cherry
Deputy General Counsel for Tax Policy and Agency Affairs
Comptroller of Public Accounts
Effective date: October 17, 2001
Proposal publication date: August 3, 2001
For further information, please call: (512) 305-9881

♦ ♦ ♦

# TITLE 37. PUBLIC SAFETY AND CORRECTIONS

# PART 7. TEXAS COMMISSION ON LAW ENFORCEMENT OFFICER STANDARDS AND EDUCATION

## CHAPTER 217. LICENSING REQUIREMENTS

### 37 TAC §217.1

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) adopts an amendment to Title 37, Texas Administrative Code §217.1 concerning the minimum standards for initial licensure, without changes to the proposed text as published in the July 13, 2001, issue of the *Texas Register* (26 TexReg 5222).

In §217.1, subsection (g)(1)(C) of this section has been changed to be consistent with Commission practice. The amendment proposes the elimination of some of the language in subsection (g)(1)(C) of this section concerning the requirement of at least one-year paid full-time employment as a law enforcement officer. This amendment also adopts a change to the effective date in subsection (n) of this section.

No written comments were received.

This new section is adopted under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

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 October 1, 2001.

TRD-200105918

Edward T. Laine

Chief, Professional Standards and Administrative Operations

Texas Commission on Law Enforcement Officer Standards and Education

Effective date: November 1, 2001

Proposal publication date: July 13, 2001

For further information, please call: (512) 936-7700

♦ ♦ ♦

### 37 TAC §217.7

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) adopts an amendment to Title 37, Texas Administrative Code §217.7 concerning the reporting of the appointment and termination of a licensee without changes to the proposed text as published in the July 13, 2001, issue of the *Texas Register* (26 TexReg 5224).

In §217.7, subsection (d) of this section has been amended to be consistent with Commission practice. In addition, §217.7 is being changed to be consistent with the philosophy of the rules committee. It was not the intent of the committee to require all persons transferring from one agency to another to meet the current minimum standards for licensure. The committee did discuss the issue and felt that it would be appropriate to require those with at least a two year break in service to meet the current minimum standards for licensure. This amendment also adopts a change to the effective date in subsection (i) of this section.

No written comments were received.

This new section is adopted under Texas Occupations Code Annotated, Chapter 1701, §1701.151 which authorizes the Commission to promulgate rules for the administration of this chapter.

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 October 1, 2001.

TRD-200105917

Edward T. Laine

Chief, Professional Standards and Administrative Operations

Texas Commission on Law Enforcement Officer Standards and Education

Effective date: November 1, 2001

Proposal publication date: July 13, 2001

For further information, please call: (512) 936-7700

♦ ♦ ♦

# TITLE 43. TRANSPORTATION

## PART 1. TEXAS DEPARTMENT OF TRANSPORTATION

### CHAPTER 1. MANAGEMENT

### SUBCHAPTER F. ADVISORY COMMITTEES

### 43 TAC §1.84

The Texas Department of Transportation adopts amendments to §1.84, concerning statutory advisory committees. Section 1.84 is adopted without changes to the proposed text as published in the August 10, 2001, issue of the *Texas Register* (26 TexReg 5996) and will not be republished.

EXPLANATION OF ADOPTED AMENDMENTS

Senate Bill 195, 77th Legislature, 2001, amended Transportation Code, Subchapter C, Chapter 201, by adding §201.114 to establish a Border Trade Advisory Committee and to provide that the Transportation Commission may adopt rules to govern it.

Government Code, §2110.005, provides that a state agency that is advised by an advisory committee shall adopt rules that state the purpose of the committee and describe the task of the committee and the manner in which the committee will report to the agency. Government Code, §2110.008, provides that a state agency shall establish by rule a date on which the committee will automatically be abolished unless the governing body of the agency affirmatively votes to continue the committee in existence.

The amendments to §1.84 add new subsection (f) to meet these statutory requirements.

New subsection (f)(1) sets forth the purpose of the Border Trade Advisory Committee.

New subsection (f)(2) establishes the membership of the committee. The committee will consist of seven members with staggered terms of three years each. The commission may consider all relevant facts in selecting advisory committee members, including the desirability of geographic and occupational diversity. These provisions are intended to ensure that the committee will be small enough to be effective, but large enough to reflect various perspectives on border trade.

New subsection (f)(3) sets forth the duties of the committee. These duties are mostly derived from the language of Transportation Code, §201.114. The committee is also directed to undertake other duties as requested by the commission or the department.

New subsection (f)(4) provides for meetings at least annually. This permits the number and timing of meetings to be adjusted depending on the committee's workload at any given time.

New subsection (f)(5) provides that the committee will not be involved in rulemaking. This will permit the committee to concentrate on the broader policy issues set forth in Transportation Code, §201.114, and in new §1.84(f)(3).

New subsection (f)(6) sets a sunset date of December 31, 2005, for the committee.

COMMENTS

No comments were received on the proposed amendments.

STATUTORY AUTHORITY

The amendments are adopted under Transportation Code, §201.101, which provides the Texas Transportation Commission with the authority to establish rules for the conduct of the work of the Texas Department of Transportation. In addition, the amendments are adopted under Government Code, Chapter 2110, which provides that a state agency that is advised by an advisory committee shall adopt rules that state the purpose of the committee, describe the task of the committee, state the manner in which the committee will report to the agency, and establish a date on which the committee is abolished unless the governing body of the agency affirmatively votes to continue the committee in existence. The amendments are also adopted under Transportation Code, §201.114(b), which authorizes the adoption of rules with respect to the Border Trade Advisory Committee.

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 September 27, 2001.

TRD-200105854
Richard D. Monroe
General Counsel
Texas Department of Transportation
Effective date: October 17, 2001
Proposal publication date: August 10, 2001
For further information, please call: (512) 463-8630

♦ ♦ ♦

## CHAPTER 3. PUBLIC INFORMATION
## SUBCHAPTER B. ACCESS TO OFFICIAL RECORDS

### 43 TAC §§3.10 - 3.14

The Texas Department of Transportation adopts amendments to §§3.10-3.14, concerning access to official records. Sections 3.10-3.14 are adopted without changes to the proposed text as published in the August 10, 2001, issue of the *Texas Register* (26 TexReg 5999) and will not be republished.

EXPLANATION OF ADOPTED AMENDMENTS

House Bill 1922, 77th Legislature, 2001, created a right for an individual to request that government-held information about that individual be corrected. It required each state agency to establish reasonable procedures allowing information to be corrected.

House Bill 1544, 77th Legislature, repealed Transportation Code, Chapter 731 concerning the disclosure of personal information from motor vehicle records. It also clarified that statutory provisions relating to the release of accident reports apply only to certain legally required accident reports filed under Transportation Code, Chapters 550 and 601. In addition, House Bill 1544 conformed Transportation Code, Chapter 730 more closely to federal law by eliminating the requirement that a motorist elect not to release personal information contained in motor vehicle records.

Sections 3.10-3.14 are amended throughout to conform to the provisions of House Bills 1922 and 1544. Amendments are also made to conform the rules more closely to current language and to eliminate unnecessary language that merely duplicates statutory provisions. Additional nonsubstantive changes are made to enhance clarity and to improve grammar.

Section 3.10 is amended to clarify that the release of public information is governed by other laws, in addition to the Public Information Act.

Section 3.11 is amended to eliminate definitions of words that will no longer be used in the rules. The definition of personal information is amended to conform to the language of HB 1544 with regard to accident reports. The definition of programming is amended to eliminate the requirement that programming be performed in computer code to reflect the greater flexibility of current computers.

Section 3.12(a)(3)(B)(iii) is amended to eliminate the condition that a person must request that the department restrict the release of personal information. House Bill 1544 removed this condition.

Section 3.12(a)(4) and (5) are eliminated because they relate to the substantive law governing release of information, which is set forth more completely in Government Code, Chapter 552. In addition, §3.12(a)(5) is no longer accurate because the law governing accident reports was restricted by House Bill 1544 to certain legally required accident reports filed under Transportation Code, Chapters 550 and 601.

Section 3.12(e)(1)(A) is eliminated because it relates to the substantive law governing release of information, which is set forth more completely in Government Code, Chapter 552.

Section 3.12(e)(1)(B) is eliminated because House Bill 1544 repealed the statutory provisions requiring a person to request that personal information in motor vehicle records not be disclosed.

Section 3.12(f)(5) is amended to add General Counsel as a certifying official to conform to subsection (a)(1)(A) of this section.

Under §3.12, subsection (i) is added in response to House Bill 1922, which requires the department to establish a procedure for correcting information without imposing undue burdens. The procedure set forth in this subsection is designed to be flexible and decentralized so it can be molded to conform to the widely varying operations of different districts, divisions, and offices of the department. The procedure is also designed to avoid abuse by precluding undefined requests to correct all records without further specificity and by clarifying that official documents, such as vehicle titles and registrations, overweight permits, and occupational licenses, may not be changed without following procedures that are already established.

Section 3.13(a) is amended to eliminate the reference to the cost of weekly motor vehicle record updates when the tape is provided by the requestor. The department no longer permits requestors to provide their own tapes.

Section 3.13(f)(1) is amended to clarify that costs of public information will be waived for employees who file grievance proceedings only to the extent that requested information is relevant to those proceedings. This conforms to current practice, under which fees are not waived to subsidize broad fishing expeditions of no direct relevance to grievance proceedings. The determination of relevance is made by the Office of General Counsel, which has general responsibility for advising the department with regard to the Public Information Act.

Section 3.13(f)(2) is amended to conform to current practice, under which district engineers, division directors, and office directors are permitted to waive public information fees if waiver is in the public interest or if the fees would be minimal.

Section 3.14 is amended to removed reference to Transportation Code, Chapter 231 and to improve readability.

COMMENTS

No comments were received on the proposed amendments.

STATUTORY AUTHORITY

The amendments are adopted under Transportation Code, §201.101, which provides the Texas Transportation Commission with the authority to establish rules for the conduct of the work of the Texas Department of Transportation.

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 October 1, 2001.

TRD-200105895
Richard D. Monroe
General Counsel
Texas Department of Transportation
Effective date: October 21, 2001
Proposal publication date: August 10, 2001
For further information, please call: (512) 463-8630

♦ ♦ ♦

## CHAPTER 9. CONTRACT MANAGEMENT
## SUBCHAPTER B. HIGHWAY IMPROVEMENT CONTRACTS

### 43 TAC §9.14

The Texas Department of Transportation adopts amendments to §9.14 concerning highway improvement contracts. Section 9.14 is adopted without changes to the proposed text as published in the August 10, 2001, issue of the *Texas Register* (26 TexReg 6004) and will not be republished.

EXPLANATION OF ADOPTED AMENDMENTS

Transportation Code, Chapter 223, Subchapter A, prescribes the method by which the Texas Department of Transportation receives competitive bids for the improvement of highways that are a part of the state highway system. Pursuant to this authority, the commission has previously adopted §§9.10-9.20 to specify the process by which the department will award and execute.

H.B. 1138, 77th Legislature, 2001, added Transportation Code, §223.014, to provide that if the department requires a proposal guaranty as a condition of bidding for a contract, the guaranty may be in the form of a cashier's check or money order, a bid bond, or any other method the department determines to be suitable. Section 9.14(d) currently allows a bidder to submit a bid bond only for a project involving less than $300,000. To comply with H.B. 1138, §9.14(d)(2) is amended to allow the use of bid bonds as a proposal guaranty for all highway improvement contracts.

COMMENTS

No comments were received on the proposed amendments.

STATUTORY AUTHORITY

The amendments are adopted under Transportation Code, §201.101, which provides the Texas Transportation Commission with the authority to establish rules for the conduct of the work of the Texas Department of Transportation, and more specifically, Transportation Code, §§223.001-223.014, which authorize the Texas Department of Transportation to competitively bid highway improvement contracts.

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 October 1, 2001.

TRD-200105894
Richard D. Monroe
General Counsel
Texas Department of Transportation
Effective date: October 21, 2001
Proposal publication date: August 10, 2001
For further information, please call: (512) 463-8630

♦ ♦ ♦

# 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 Department of Health

**Title 25, Part 1**

The Texas Department of Health (department) will review and consider for readoption, revision or repeal Title 25, Texas Administrative Code, Part 1, Chapter 289. Radiation Control, Subchapter D. General, §289.202.

This review is in accordance with the requirements of the Texas Government Code, §2001.039, the General Appropriations Act, Article IX, §9-10.13, 76th Legislature, 1999.

An assessment will be made by the department as to whether the reasons for adopting or readopting the rule continue to exist. This assessment will be continued during the rule review process. Each rule will be reviewed to determine whether it is obsolete, whether the rule reflects current legal and policy considerations, and whether the rule reflects current procedures of the department. The review of all rules must be completed by August 31, 2003.

Comments on the review may be submitted in writing within 30 days following the publication of this notice in the *Texas Register* to Linda Wiegman, Office of General Counsel, Texas Department of Health, 1100 West 49th Street, Austin, Texas 78756. Any proposed changes to this rule as a result of the review will be published in the Proposed Rule Section of the *Texas Register* and will be open for an additional 30 day public comment period prior to final adoption or repeal by the department.

TRD-200105847
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: September 26, 2001

♦ ♦ ♦

Texas Commission on Law Enforcement Officer Standards and Education

**Title 37, Part 7**

Notice of Intention to Review: In accordance with Review of Agency Rules whereas State agencies are directed to review their administrative rules by the Government Code §2001.039, added by Acts, 1999, 76th Legislature, Chapter 1499, Art. 1, Section 1.11, the Texas Commission on Law Enforcement Officer Standards and Education files this notice of proposed intention to review Texas Administrative Code, Title 37 - Public Safety, Part 7, Texas Commission on Law Enforcement Officer Standards and Education.

The Texas Commission on Law Enforcement Officer Standards and Education comprehensive rules review is conducted following every legislative session and reported to the Commission at its regularly scheduled meeting in June. Rules, which do not require revision, are presented at the September meeting for reinstatement. Rules, which require revision, or new rules, are developed and presented as proposals at the September Commission meeting. Rules, which require revision, or new rules coming to the attention of the Commission at any other time, are considered and developed, as necessary.

Chapter 1701 of the Occupations Code gives the Commission its authority. Section 1701.151 General Powers of Commission; Rulemaking Authority, states that the Commission may adopt rules for the administration of this chapter.

The Commission on Law Enforcement initiated this plan September 28, 1999.

Written comments should be submitted to Dr. D.C. Jim Dozier, Executive Director, Texas Commission on Law Enforcement Officer Standards and Education, 6330 U.S. Highway 290 East, Suite 200, Austin, Texas 78723, or by facsimile (512) 963-7714.

The Commission on Law Enforcement approved on September 14, 2001, the below proposed amendments to Title 37, Texas Administrative Code.

§211.1. Definitions.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §211.1 concerning definitions. For clarification purposes, the proposed amendment adds a definition for the term "training cycle". The amendment also proposes the renumbering of the subsections of this section as well as a change to the effective date in subsection (b) of this section.

§211.27. Reporting Responsibilities of Individuals.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §211.27 concerning the reporting responsibilities of individuals. For consistency purposes, changes were made in subsections (a) and (c) of this section. The language, which previously read, "a person who holds a commission license or certificate," was deleted and was replaced by the term "licensee". The language is being provided to clarify that the Commission takes administrative action against licensees, not certificates that they hold. A proposed change was also made to the effective date in subsection (d) of this section.

§215.3. Academy Licensing.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §215.3 concerning academy licensing. For consistency purposes, changes were made to some of the terms used in a number of the subsections. The subsections that were affected were (a)(3) and (6); (b)(5), (7) and (8); (A)(B) and (C); (d); (e)(1) and (3); (h)(2) of this section; and a change was made in the effective date in subsection (j) of this section.

§215.5. Contractual Training.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §215.5 concerning contractual training. For clarification purposes the term "requesting party" was changed to the term "applicant" in subsection (e)(1)(A) of this section. The only other proposed change to this section was to the effective date in subsection (i) of this section.

§215.15. Enrollment Standards and Training Credit.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §215.15 concerning enrollment standards and training credit. Additional language provides clarification regarding the Commission's role, that training credit will be granted for courses conducted by a licensed academy as provided in the Commission's rules. In addition, the language provided in subsection (d)(1)(2)(3) of this section explains what records an academy must have on file for individuals who enroll in any basic peace officer training program which provides instruction in defensive tactics, arrest procedures, firearms, or use of a motor vehicle for law enforcement purposes. In addition, the language provided in subsection (e)(4) of this section is intended to minimize incidents where licensees obtain training credit by deceitful means. The other proposed changes in §215.15 include the renumbering of the subsections and a proposed change to the effective date in subsection (g) of this section.

§215.17. Distance Education.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §215.17 concerning distance education. Additional language provided in subsection (d) of this section provides clarification regarding distance education courses and the Commission's role. In addition, the added language provided in this subsection is intended to minimize incidents where licensees obtain distance education training credit by deceitful means. The only other proposed change in §215.17 includes a change to the effective date in subsection (f) of this section.

§217.1. Minimum Standards for Initial Licensure and §217.7. Reporting the Appointment and Termination of a License had adopted amendments with an effective date of November 1, 2001. The Commission on Law Enforcement reviewed in accordance with the Review of Agency Rules §217.1 and §217.7 and will make proposed rule amendments after the November 1, 2001 effective date.

§217.9 Continuing Education Credit for Licensees.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes to adopt an amendment to Title 37, Texas Administrative Code §217.9 concerning continuing education credit for licensees. In subsection (b) the term of this section, "shall" was deleted and the term "may" was substituted for clarification and consistency with the Commission's rules. In subsection (b)(5) of this section, the proposed amendment clarifies that the Commission may refuse credit for more than one presentation of a course by an instructor, per training cycle. The proposed amendment gives the Commission authority to take administrative action against licensees that claim credit in instances where credit was obtained by deceitful means. Additional language in subsection (b)(6) of this section, also serves to clarify that the Commission may refuse credit for the continuing education course(s) if the course(s) is obtained by deceitful means. The amendment also proposes a change to the effective date in subsection (d) of this section.

§217.11. Legislatively Required Continuing Education for Licensees.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §217.11 concerning legislatively required continuing education for licensees. Proposed amendments to this section clarify that the Commission will track the legislatively required courses taken and completed by licensees every four years versus every two years. In subsections (a), (b) and (e) of this section language was added for clarification purposes. In subsection (h) of this section language was added to clarify when the commission may discipline an individual for failure to complete 40 hours of training in either or both of the 24 month units within a training cycle. In subsection (j) of this section language was added to clarify that individuals licensed as peace officers shall attend a course, developed by the commission, on asset forfeiture no later than September 1, 2002. In subsection (k) of this section, language was added to clarify that individuals licensed as peace officers shall attend a course, developed by the commission, on racial profiling no later than September 1, 2003. In subsection (l) of this section, language was added to clarify that all peace officers must meet the continuing education requirements except where exempt by law. This rule is written to conform with continuing education requirements for peace officers as set forth by the Legislature in the 2001 session. The only other proposed amendment was to the effective date in subsection (m) of this section.

§217.17. Active License Renewal

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §217.17 concerning active license renewals. The proposed amendment to this subsection clarifies that the Commission will track the legislatively required courses taken and completed by licensees every four years versus every two years and that active licensees who have met the current legislatively required continuing education courses will have their license(s) automatically renewed on the last day of the training cycle. The amendments to subsection (c) and (d) of this section propose changes to the term reactivation and the term reinstated. These terms are being substituted by the terms reinstatement in subsection (c) and (d) of this section. A change is also being proposed to the effective date in subsection (e) of this section.

§217.19. Reactivation of a License.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §217.19 concerning reactivation of a license. The proposed amendment to this subsection clarifies the process that will be used by the Commission to allow individuals to maintain an active license status by completing the legislatively required continuing education. Subsection (f) of this section also clarifies the process that will be used for any jailer license issued after March 1, 2001. Jailers will be required to retest if out more than 2 years effective March 1, 2001. The amendment also proposed a change to the effective date in subsection (h) of this section.

§221.1. Proficiency Certificate Requirements.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §221.1 concerning proficiency certificate requirements. The proposed amendment to this subsection clarifies that an active licensee, who is not commissioned, will still be able to accrue certificates. Currently, a active licensee cannot earn certificates if not commissioned. The amendment also proposes a change to the effective date in subsection (f) of this section.

§221.3. Peace Officer Proficiency.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §221.3 concerning peace officer proficiency. The proposed amendment to this subsection clarifies that in order to qualify for an intermediate peace officer proficiency certificate, new legislation requires that an applicant must meet all proficiency requirements including two additional courses. In subsection (3)(F) and (G) of this section new legislation mandates that two new courses, an asset forfeiture course and a racial profiling course be completed if the basic peace officer certificate was issued or qualified for on or after January 1, 1987, the licensee must also complete all of the current intermediate peace officer certification courses. The amendment also proposes a change to the effective date in subsection (d) of this section.

§221.13. Emergency Telecommunications Proficiency.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §221.13 concerning emergency telecommunications proficiency. The proposed amendment to subsection (b)(3) and (4) of this section clarifies that in order to qualify for an intermediate emergency telecommunications proficiency certificate, new legislation requires that an applicant must meet all proficiency requirements including 120 hours of training and if the basic telecommunications certificate was issued or qualified for on or after January 1, 2000, successful completion of the required courses as specified by the Commission, which include: Cultural Diversity, Ethics in Law Enforcement, Crisis Communications, TCIC/NCIC for Full Access Operators; NLETS/TLETS; or Criminal Law; and Spanish for Law Enforcement. Subsection (c)(3) of this section clarifies that to qualify for an advanced telecommunications proficiency certificate, an applicant must meet all proficiency requirements including: an intermediate telecommunications certificate, at least four years of experience in public safety telecommunications, and 240 training hours. The amendment also proposes a change to the effective date in subsection (d) of this section.

§223.3 Answer Required.

The Texas Commission on Law Enforcement Officer Standards and Education (Commission) proposes an amendment to Title 37, Texas Administrative Code §223.3 concerning the answer required section. For consistency purposes, the proposed amendment to subsection (d)(3) of this section, includes the deletion of the abbreviated term, "Tex. Admin." which will be substituted by the term, "Texas Administrative Code." The amendment also proposes a change to the effective date in subsection (f) of this section.

The Texas Commission on Law Enforcement approved on September 14, 2001, the below proposed re-adoptions with no changes to Title 37, Texas Administrative Code.

§211.3. Public Information.

§211.5. Licensee Lists.

§211.7. Meeting Dates and Procedures.

§211.9. Execution of Orders Showing Action Taken at Commission Meetings.

§211.11. Contemplated Rule Making.

§211.13. Notice of Commission Rulemaking.

§211.15. Specific Authority to Waive Rules.

§211.17. Fees and Payment.

§211.19. Forms and Applications.

§211.21. Issuance of Duplicate or Delayed Documents.

§211.23. Date of Licensing or Certification.

§211.25. Date of Appointment.

§211.29. Responsibilities of Agency Chief Administrators.

§211.31. Memorandum of Understanding on Continuity of Care.

§211.33. Law Enforcement Achievement Awards.

§215.1. Licensing of Training Providers.

§215.7. Training Provider Advisory Boards.

§215.9. Training Coordinator.

§215.11. Training Provider Evaluations.

§215.13. Risk Assessment.

§217.3. Application for License and Initial Report of Appointment.

§217.5. Denial.

§217.13. Reporting Legislatively Required Continuing Education.

§217.15. Waiver of Legislatively Required Continuing Education.

§217.21. Firearms Proficiency Requirements.

§217.23. Training Standards for Conditional Reserve License.

§219.1. Eligibility to Take State Examinations.

§219.3. Examination Administration.

§219.5. Examinee Requirements.

§219.7. Scoring of Examinations.

§221.5. Jailer Proficiency.

§221.7. Investigative Hypnosis Proficiency.

§221.9. Standardized Field Sobriety Testing Proficiency (SFST).

§221.11. Mental Health Officer Proficiency.

§221.15. Crime Prevention Inspector Proficiency.

§221.17. Homeowners Insurance Inspector Proficiency.

§221.19. Firearms Instructor Proficiency.

§221.21. Firearms Proficiency for Community Supervision Officers.

§221.23. Academic Recognition Award.

§221.25. Civil Process Proficiency.

§221.27. Instructor Proficiency.

§223.1. License Action and Notification.

§223.5. Filing of Documents.

§223.7. Contested Cases and Hearings.

§223.9. Place and Nature of Hearings.

§223.11. Proposal for Decision and Exceptions or Briefs.

§223.13. Voluntary Surrender of License.

§223.15. Suspension of License.

§223.17. Reinstatement of a License.

§223.19. Revocation of License.

§223.21. Appeal.

§225.1. Issuance of Contract Jailer License.

§229.1. General Eligibility of Deceased Texas Peace Officers.

§229.3. Specific Eligibility of Deceased Texas Peace Officers.

§229.5. Determination Standards.

§229.7. Deaths Not Included.

TRD-200105935
Edward T. Laine
Chief, Professional Standards and Administration Operations
Texas Commission on Law Enforcement Officer Standards and Education
Filed: October 1, 2001

♦ ♦ ♦

## Adopted Rule Reviews

### Office of the Governor

**Title 1, Part 1**

The Office of the Governor has completed its review of Texas Administrative Code, Title 1, Part 1, Chapter 3 (Criminal Justice Division) and Chapter 5 (Budget and Planning Office). The review was conducted in accordance with the requirements of Texas Government Code, §2001.039, which requires state agencies to review and consider for re-adoption their administrative rules every four years.

The notice of review was published in the August 31, 2001, issue of the *Texas Register* (26 TexReg 6736). The Office of the Governor received no comments regarding the proposed rule review or the amendments and repeals to Chapter 3 (Criminal Justice Division), which were proposed in the July 20, 2001, issue of the *Texas Register* (26 TexReg 5311) and adopted in the August 31, 2001, issue of the *Texas Register* (26 TexReg 6645).

After completing the review, the Office of the Governor readopts Texas Administrative Code, Title 1, Part 1, Chapter 3 (Criminal Justice Division) and Chapter 5 (Budget and Planning Office) including the amendments and repeals to Chapter 3, effective September 9, 2001. The Office of the Governor determined that the reason for adopting these rules continues to exist.

TRD-200105905
David Zimmerman
Assistant General Counsel
Office of the Governor
Filed: October 1, 2001

♦ ♦ ♦

### Texas Natural Resource Conservation Commission

**Title 30, Part 1**

The Texas Natural Resource Conservation Commission (commission) adopts the rules review of Chapter 323, Waste Disposal Approvals, and readopts Chapter 323, in accordance with Texas Government Code, §2001.039, and the General Appropriations Act, Article IX, §9 - 10.13, 76th Legislature, 1999, which require state agencies to review and consider for readoption each of their rules every four years. A review must include an assessment of whether the reasons for the rules continue to exist. The proposed notice of intention to review was published in the July 27, 2001 issue of the *Texas Register* (26 TexReg 5667).

CHAPTER SUMMARY

Chapter 323 allows the executive director to develop a system for evaluating waste disposal facilities to determine if the design and operation merit state approval. The chapter provides conditions under which a person whose waste disposal facility attained an approved rating can erect signs to show that the facility has been approved, and establishes procedures used to evaluate waste disposal facilities after the rating system has been established.

ASSESSMENT OF WHETHER THE REASONS FOR THE RULES CONTINUE TO EXIST

The commission determined that the reasons for the rules in Chapter 323 continue to exist. These rules implement provisions of Texas Water Code, §26.033, Rating of Waste Disposal Systems. Section 26.033 requires the commission to provide by rule for a system of approved ratings for municipal waste disposal systems and other waste disposal systems which the commission may designate.

PUBLIC COMMENT

The public comment period closed on August 27, 2001. No comments on whether the reasons for the rules continue to exist were received.

TRD-200105855
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Filed: September 27, 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: 4 TAC §20.22(a)

| Pest Mgmt Zone | Planting Dates | Destruction Deadline | Destruction Method (also see footnotes) |
|---|---|---|---|
| 1 | Feb. 1 - March 31 | September 1 | shred and plow [a,b] |
| 2 – Area 1 | No dates set | September 1 | shred and plow [a,b] |
| 2 – Area 2 | No dates set | September 1 | shred and plow [a,b] |
| 2 – Area 3 | No dates set | September 1 | shred and plow [a,b] |
| 2 – Area 4 | No dates set | October 1 | shred and plow [a] |
| 3 -Area 1 (Matagorda County) | March 5 - May 15 | October 1 | shred and plow [a,b] |
| 3 -Area 1 (Jackson & Wharton Counties) | March 5 - May 15 | October 15 | Shred and plow [a,b] |
| 3 - Area 2 | March 5 - May 15 | October 29 | shred and plow [a,b] |
| 4 | No dates set | October 10 | shred and plow [a,b] |
| 5 | No dates set | October 20 | shred and/or plow [a,c] |
| 6 | No dates set | October 31 | shred and/or plow [a,c] |
| 7 | March 20 - May 31 | November 30 | shred and/or plow [a,c] |
| 8 | March 20 - May 31 | November 30 | shred and/or plow [a,c] |
| 9 | No dates set | March 15 | shred and plow [b,d] |
| 10 | No dates set | February 1 | shred and plow [b,d] |

a/ Alternative destruction methods are allowed (see paragraph (b)).

b/ Destruction shall be performed in a manner to prohibit the presence of live cotton plants.

c/ Destruction shall periodically be performed to prevent presence of fruiting structures.

d/ Soil shall be tilled to a depth of 2 or more inches in Zone 9, and to a depth of 6 or more inches in Zone 10.

Figure: 16 TAC §25.476(f)(7)(B)(ii)

SRR / TS,

where

| | |
|---|---|
| SRR = | the statewide REC requirement, in MWh, as calculated by the REC Trading Program Administrator for the compliance period coinciding with the Electricity Facts label disclosure, and |
| TS = | total MWh sales for all competitive retailers to Texas customers during the compliance period coinciding with the Electricity Facts label disclosure. |

Figure: 30 TAC §101.353(a)

$$A = [B] - X\left[B - \left(\frac{LA_{HA} * EF_{final}}{2000}\right)\right]$$

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:

$$B = \frac{(LA_{97} * EF_{97}) + (LA_{98} * EF_{98}) + (LA_{99} * EF_{99})}{3(2000)}$$

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 facility's emission factor for 1997 or the emission specifications under §§117.106, 117.206, and 117.475 of this title (relating to Emission Specifications for Attainment Demonstration; and Emission Specifications) (ESAD) whichever is higher, 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;

$EF_{98}$ = the facility's emission factor for 1998 or the emission specifications under ESAD, whichever is higher, 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;

$EF_{99}$ = the facility's emission factor for 1999 or the emission specifications under ESAD, whichever is higher, 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.

(B) For existing facilities not in operation prior to January 1, 1997 and that have been in operation less than five complete consecutive calendar years beginning after the end of the adjustment period and have not established two years of baseline data:

$$B = \frac{LA_{Allowable} * EF_{Allowable}}{2000}$$

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 or the emission specifications under ESAD, whichever is higher, authorized by the executive director until such time two consecutive calendar years of actual emission data is available.

(C) For existing facilities not in operation prior to January 1, 1997 and that have established two consecutive calendar years of baseline data out of the first five years of operation following the end of the adjustment period:

$$B = \frac{(LA_{Year-1} * EF_{Year-1}) + (LA_{Year-2} * EF_{Year-2})}{2(2000)}$$

Where: $LA_{Year-1}$ = the facility's level of activity, as certified by the executive director, for the first of any two consecutive years within the first five years of operation;

$LA_{Year-2}$ = the facility's level of activity, as certified by the executive director, for the second of any two consecutive years within the first five years of operation;

$EF_{Year-1}$ = the facility's emission factor or the emission specifications under ESAD, whichever is higher, 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 the first of any two consecutive years within the first five years of operation;

$EF_{Year-2}$ = the facility's emission factor or the emission specifications under ESAD, whichever is higher, 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 the second of any two consecutive years within the first five years of operation.

(3) X = reduction factor, where:

(A) For all boilers, auxiliary steam boilers, and stationary gas turbines (including duct burners used in turbine exhaust ducts) within an electric power generating system, as defined in §117.10(13)(A)(iii) of this title (relating to Definitions), located in the Houston/Galveston nonattainment area:

(i) for January 1, 2002 through March 31, 2003, X = 0.00;

(ii) for April 1, 2003 through March 31, 2004, X = 0.489;

(iii) on or after April 1, 2004 through March 31, 2007, X = 0.978;

(iv) on or after April 1, 2007, X = 1.00;

(B) If the emissions specifications in §117.106(c)(5) of this title apply, then:

(i) for January 1, 2002 through March 31, 2003, X = 0.00;

(ii) for April 1, 2003 through March 31, 2004, X = 0.50;

(iii) on or after April 1, 2004, X = 1.00;

(C) For all other facilities:

(i) for January 1, 2002 through March 31, 2004, X = 0.00;

(ii) for April 1, 2004 through March 31, 2005, X = 0.389;

(iii) for April 1, 2005 through March 31, 2006, X = 0.667;

(iv) for April 1, 2006 through March 31, 2007, X = 0.778;

(v) on or after April 1, 2001, X = 1.00;

(D) If the emissions specifications in §117.206(c)(18) of this title apply, then:

(i) for January 1, 2002 through March 31, 2004, X=0.00;

(ii) for April 1, 2004 through March 31, 2005, X=0.47;

(iii) for April 1, 2005 through March 31, 2006, X=0.80;

(iv) for April 1, 2006 through March 1, 2007, X=0.93;

(v) on or after April 1, 2007, X=1.00;

(E) 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 existing facilities, 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, beginning after the end of the adjustment period; or

(ii) when two complete consecutive calendar years of actual level of activity data is available, beginning after the end of the adjustment period, 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)(4), 117.206(c)(17), or 117.475(c)(6) of this title, 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)(4), 117.206(c)(17) or 117.475(c)(6) of this title.

Figure: 30 TAC §101.354(b)

$$A = \frac{LA_{CP} * EF_{CP}}{2000}$$

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 1: 30 TAC Chapter 117 - Preamble

| Emission Standards<br>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) | | 0.80 (0.60) |
| 8≤kW<19 (11≤hp<25) | Tier 1 | 2000 | 9.5 (7.1) | 6.6 (4.9) | 0.80 (0.60) |
| | Tier 2 | 2005 | 7.5 (5.6) | | 0.80 (0.60) |
| 19≤kW<37 (25≤hp<50) | Tier 1 | 1999 | 9.5 (7.1) | 5.5 (4.1) | 0.80 (0.60) |
| | Tier 2 | 2004 | 7.5 (5.6) | | 0.60 (0.45) |
| 37≤kW<75 (50≤hp<100) | Tier 2 | 2004 | 7.5 (5.6) | 5.0 (3.7) | 0.40 (0.30) |
| | Tier 3 | 2008 | 4.7 (3.5) | | |
| 75≤kW<130 (100≤hp<175) | Tier 2 | 2003 | 6.6 (4.9) | 5.0 (3.7) | 0.30 (0.22) |
| | Tier 3 | 2007 | 4.0 (3.0) | | |
| 130≤kW<225 (175≤hp<300) | Tier 2 | 2003 | 6.6 (4.9) | 3.5 (2.6) | 0.20 (0.15) |
| | Tier 3 | 2006 | 4.0 (3.0) | | |
| 225≤kW<450 (300≤hp<600) | Tier 2 | 2001 | 6.4 (4.8) | 3.5 (2.6) | 0.20 (0.15) |
| | Tier 3 | 2006 | 4.0 (3.0) | | |
| 450≤kW≤560 (600≤hp≤750) | Tier 2 | 2002 | 6.4 (4.8) | 3.5 (2.6) | 0.20 (0.15) |
| | Tier 3 | 2006 | 4.0 (3.0) | | |
| kW>560 (hp>750) | Tier 2 | 2006 | 6.4 (4.8) | 3.5 (2.6) | 0.20 (0.15) |

Figure 2: 30 TAC Chapter 117 - Preamble

**POTENTIAL $NO_X$ EMISSION REDUCTIONS FROM ALTERNATE ESADS* BY POINT SOURCE CATEGORY FOR HOUSTON/GALVESTON NONATTAINMENT AREA COUNTIES - Revised 9/26/01**

| Category | 1997 Emissions (tons per day (tpd)) | % of Total Point | Tier III Reductions as adopted on 12/6/00 (%; tpd) | Tier III Reductions as adopted on 9/26/01 (%; tpd) | Tier III Reductions if alternate ESADs are implemented in the future (%; tpd) |
|---|---|---|---|---|---|
| Utility Boilers | 196.44 | 29.4 | 93%; 184 tpd | 90%; 176 tpd[1] | 86%; 169 tpd[1] |
| Turbines (+Duct Burners) | 155.65 | 23.3 | 91%; 141 tpd | 91%; 141 tpd | 78%; 122 tpd |
| Heaters and Furnaces | 110.12 | 16.5 | 88%; 97 tpd | 88%; 97 tpd | 71%; 79 tpd |
| IC Engines | 86.37 | 12.9 | 88%; 75 tpd | 89%; 77 tpd[2] | 88%; 76 tpd[2] |
| Industrial Boilers | 85.98 | 12.9 | 92%; 79 tpd | 92%; 79 tpd | 89%; 76 tpd |
| Other | 32.99 | 4.9 | 59%; 19 tpd | 59%; 19 tpd | 49%; 16 tpd |
| Overall Point Source | 667.56 | 100.0 | 89%; 595 tpd | 88%; 588 tpd | 81%; 538 tpd |

*ESAD = Emission specifications for attainment demonstration

[1]Takes into account the decrease in emission reductions of 7.42 tpd due to the revisions to the utility boiler ESADs in §117.106(c)(1) of this title
[2]Takes into account the 1.12 tpd emission reduction due to the new diesel engine ESADs in §117.206(c)(9)(D) of this title

Figure 3: 30 TAC Chapter 117 - Preamble

**SUBCATEGORIES - POINT SOURCE POTENTIAL $NO_X$ EMISSION REDUCTIONS FROM ALTERNATE ESADS FOR HOUSTON/GALVESTON NONATTAINMENT AREA COUNTIES - Revised 9/26/01**

| Category | 1997 Emissions (tons per day (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 | 90%; 70.55 tpd | 0.020 lb/MMBtu |
| Gas Tangential-fired | 13.34 | | 5 | 30%; 4.00 tpd | 90%; 12.01 tpd | 87%; 11.58 tpd | 0.020 lb/MMBtu |
| Coal Wall-fired | 56.92 | | 2 | 45%; 25.61 tpd | 85%; 48.38 tpd | 89%; 50.88 tpd | 0.040 lb/MMBtu |
| Coal Tangential-fired | 47.78 | | 2 | 60%; 28.67 tpd | 85%; 40.61 tpd | 90%; 42.85 tpd | 0.040 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 | 90%; 176 tpd | |
| Turbines and Duct Burners | 139.06[1] | | 78 | 62%; 86.22 tpd | 90%; 125.15 tpd | 92%;128.22[1] tpd | 0.015 lb/MMBtu |
| Electric Generation | 4.90 | | 16 | 61%; 2.99 tpd | 90%; 4.41 tpd | 93%; 4.58 tpd | 0.015 lb/MMBtu |
| Compressors >10MW | 6.44 | | 22 | 60%; 3.86 tpd | 90%; 5.80 tpd | 90%; 5.80 tpd | 0.015 lb/MMBtu |
| Compressors 1-10MW | 0.42 | | 40 | 0%; 0 tpd | 70%; 0.29 tpd | 70%; 0.29 tpd | 0.150 lb/MMBtu |
| Compressors <1MW | 3.16 | | 29 | 14%; 0.44 tpd | 76%; 2.40 tpd | 78%; 2.47 tpd | 0.015 lb/MMBtu |
| Elec. Peaking/Int. | 0.52 | | 4 | 0%; 0 tpd | 0%; 0 tpd | 0%; 0 tpd | -- |
| Test Cell | 1.13[1] | | 2 | 0%; 0 tpd | 0%; 0 tpd | 0%; 0 tpd | -- |
| Chemical Processing | 0.02 | | 2 | 0%; 0 tpd | 0%; 0 tpd | 0%; 0 tpd | -- |
| Emergency | 155.65 | 23.3 | 193 | 60%; 93.51 tpd | 89%; 138.05 tpd | 91%; 141 tpd | |
| Total Turbines/DBs | | | | | | | |

| Category | 1997 Emissions (tons per day (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 |
|---|---|---|---|---|---|---|---|
| Process Heaters/Furnaces | | | | | | | |
| Gas-fired ³100 MMBtuh | 88.16 | | 424 | 49%; 43.20 tpd | 90%; 79.35 tpd | 90%; 79.35 tpd | 0.010 lb/MMBtu |
| Gas-fired ³40<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 | |
| 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 | 20%; 1.08 tpd | 0%; 0 tpd | 20%; 1.08 tpd | various |
| Other Diesel | 0.20 | | 10 | 20%; 0.04 tpd | 0%; 0 tpd | 20%; 0.04 tpd | various |
| 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 | 52%; 44.63 tpd | 86%; 73.88 tpd | 89%; 76.75 tpd | |
| Industrial Boilers | | | | | | | |
| Gas-fired ³100 MMBtuh | 55.46 | | 180 | 60%; 33.28 tpd | 90%; 49.91 tpd | 96%; 53.24 tpd | 0.010 lb/MMBtu |
| RCRA BIF ³100 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 ³40 <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 (tons per day (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 ³40 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 ³20 Ht Treat | 0.17 | | 4 | 35%; 0.06 tpd | 0%; 0 tpd | 35%; 0.06 tpd | 0.09 lb/MMBtu |
| Steel Furnace ³20 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 | |

[1]Corrections from the corresponding table in the January 12, 2001 issue of the *Texas Register*

Figure 4: 30 TAC Chapter 117 - Preamble

| Combined and Pollutant-Specific Emission Standards In grams per kilowatt-hour (g/kW-hr) and grams per horsepower-hour (g/hp-hr) | | | | |
|---|---|---|---|---|
| Engine Power | Tier | Non-Methane Hydrocarbons plus $NO_x$ | NMHC | $NO_x$ |
| kW<8 (hp<11) | Tier 2 | 7.5 (5.6) | 0.8 (0.6) | 6.7 (5.0) |
| | Tier 3 | --- | ---- | ---- |
| 8≤kW<19 (11≤hp<25) | Tier 2 | 7.5 (5.6) | 0.8 (0.6) | 6.7 (5.0) |
| | Tier 3 | ---- | ---- | ---- |
| 19≤kW<37 (25≤hp<50) | Tier 2 | 7.5 (5.6) | 0.8 (0.6) | 6.7 (5.0) |
| | Tier 3 | ---- | ---- | ---- |
| 37≤kW<75 (50≤hp<100) | Tier 2 | 7.5 (5.6) | 0.5 (0.4) | 7.0 (5.2) |
| | Tier 3 | 4.7 (3.5) | 0.3 (0.2) | 4.4 (3.3) |
| 75≤kW<130 (100≤hp<175) | Tier 2 | 6.6 (4.9) | 0.6 (0.4) | 6.0 (4.5) |
| | Tier 3 | 4.0 (3.0) | 0.3 (0.2) | 3.7 (2.8) |
| 130≤kW<225 (175≤hp<300) | Tier 2 | 6.6 (4.9) | 0.6 (0.4) | 6.0 (4.5) |
| | Tier 3 | 4.0 (3.0) | 0.3 (0.2) | 3.7 (2.8) |
| 225≤kW<450 (300≤hp<600) | Tier 2 | 6.4 (4.8) | 0.4 (0.3) | 6.0 (4.5) |
| | Tier 3 | 4.0 (3.0) | 0.3 (0.2) | 3.7 (2.8) |
| 450≤kW≤560 (600≤hp≤750) | Tier 2 | 6.4 (4.8) | 0.4 (0.3) | 6.0 (4.5) |
| | Tier 3 | 4.0 (3.0) | 0.3 (0.2) | 3.7 (2.8) |
| kW>560 (hp>750) | Tier 2 | 6.4 (4.8) | 0.4 (0.3) | 6.0 (4.5) |
| | Tier 3 | ---- | ---- | ---- |

Figure: 30 TAC §117.108(c)(1)

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

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 any system 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 any system 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 before January 2, 2001;

(II) EGFs which qualify for a permit by rule under Chapter 106 of this title and have commenced construction before January 2, 2001; and

(III) EGFs which were not in operation before January 1, 1997;

(iv) After two consecutive third quarters of actual level of activity data are available for an EGF described in subsection (c)(1) of this section, variable (B)(iii) of this figure, the owner or operator may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in '101.350 of this title (relating to Definitions); and

(v) In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period described in subsection (c)(1) of this section, variable (B)(i) - (iv) of this figure. Applications seeking an alternate baseline period must be submitted by the owner or operator of the EGF to the executive director:

(I) no later than December 31, 2001; or

(II) for EGFs for which the baseline period as described in subsection (c)(1) of this section, variable (B)(i) - (iv) of this figure is not complete by December 31, 2001, no later than 90 days after completion of the baseline period.

$R_i$ = (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 §117.210(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;

(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 before January 2, 2001;

(ii) EGFs which qualify for a permit by rule under Chapter 106 of this title and have commenced construction before January 2, 2001; and

(iii) EGFs which were not in operation before January 1, 1997;

(D) After two consecutive third quarters of actual level of activity data are available for an EGF described in subsection (c)(1) of this section, variable (C) of this figure, the owner or operator may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title (relating to Definitions); and

(E) In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period described in subsection (c)(1) of this section, variable (A) - (D) of this figure. Applications seeking an alternate baseline period must be submitted by the owner or operator of the EGF to the executive director:

(i) no later than December 31, 2001; or

(ii) for EGFs for which the baseline period as described in subsection (c)(1) of this section, variable (A) - (D) of this figure is not complete by December 31, 2001, no later than 90 days after completion of the baseline period.

$R_i$ = the emission limit of §117.206(c) of this title.

Figure: 30 TAC §117.210(c)(2)

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

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. For an EGF for which the system highest 30-day period in 1997 - 1999 occurs in months other than July - September, the owner or operator may substitute the system highest 30-day period in the nine months comprising the highest three consecutive months in each year of the 1997 - 1999 period;

(B) 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;

(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 before January 2, 2001;

(ii) EGFs which qualify for a permit by rule under Chapter 106 of this title and have commenced construction before January 2, 2001; and

(iii) EGFs which were not in operation before January 1, 1997;

(D) After two consecutive third quarters of actual level of activity data are available for an EGF described in subsection (c)(1) of this section, variable (C) of this figure, the owner or operator may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. For an EGF for which the system highest 30-day period in the first two years of operation occurs in months other than July - September, the owner or operator may substitute the system highest 30-day period in the six months comprising the highest three consecutive months in any two consecutive years in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title; and

(E) In extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period described in subsection (c)(1) of this section, variable (A) - (D) of this figure. Applications seeking an alternate baseline period must be submitted by the owner or operator of the EGF to the executive director:

(i) no later than December 31, 2001; or

(ii) for EGFs for which the baseline period as described in subsection (c)(1) of this section, variable (A) - (D) of this figure is not complete by December 31, 2001, no later than 90 days after completion of the baseline period.

$R_i$ = the emission limit of §117.206(c) of this title.

Figure: 30 TAC §117.210(c)(3)

$$\text{NO}_x \text{ maximum daily cap (lb/day)} = \sum_{i=1}^{N} (H_{mi} \times R_i)$$

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.

Figure: 30 TAC §117.570(d)

$$\Delta E = \left[ LA \times \left( ER_{old} - ER_{new} \right) \times \frac{d}{2000} \right]$$

Where:

| | | |
|---|---|---|
| $\Delta E$ | = | the differential of emissions |
| $LA$ | = | the maximum level of activity |
| *HEROLD* | = | the existing $NO_x$ emission rate for the affected in lb per unit of activity |
| *ERNE* | = | the new $NO_x$ emission rate for the affected unit in lb per unit of activity |
| $d$ | = | (i) to calculate annual emission reductions, $d$ = 365 |
| | | (ii) to calculate emission reductions for the remainder of a control period, $d$ = the number of days remaining in the control period |

# 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.

## Center for Rural Health Initiatives

Request for Proposals

The Center for Rural Health Initiatives is issuing a Request for Proposals ("RFP") for the Medically Underserved Community-State Matching Incentive Program. The purpose of this RFP is to provide the applicant with the information necessary to apply for matching state grant funds under the provisions of this program.

The purpose of this program is to increase the number of physicians providing primary care in medically underserved communities, particularly rural.

USE OF FUNDS: The funds can be used to establish a medical office and ancillary facilities for diagnosing and treating patients. The optimum use of funds would be for the purchase of equipment and furnishings that would establish a new practice site. The site will continue to serve the primary care needs of the community beyond the grant period, and the physician will agree to practice for a minimum of two years.

AMOUNT OF AWARDS: The funding available for support of this program during FY 2002 is $250,000. Approximately 10 projects will be funded. Under the requirements of this program the state grants funds of up to $25,000 to match the contributions by community groups to cover start-up costs for new physicians.

ELIGIBLE APPLICANTS: An eligible community must be in an underserved area as determined by the U.S. Department of Health and Human Services or the Texas Department of Health. The community must make a commitment of $15,000 - $25,000 in contributions toward the project and contract with a physician eligible to participate in this program.

Eligible physicians include those in family/general practice, general pediatrics, general internal medicine, or general obstetrics/gynecology. The physician must be licensed to practice in the State of Texas, have completed an accredited residency program, and have contracted with the community to provide full-time primary care for at least two years. A physician who completed residency within the last ten years will be given priority consideration.

EVALUATION AND SELECTION: The Center will prioritize the eligible communities to assure that the neediest are provided grants. The prioritization process will quantify indicators of need that may include, but are not limited to, the following: no practicing primary care physicians; only one primary care physician and a population of at least 2,000; no federally or state-funded primary care clinic; no practicing physician assistants or nurse practitioners; the participating physician will be the only physician practicing in one of the primary care specialties; a large minority population, if the participating physician is a member of the same minority group; designation by the United States Department of Health and Human Services as a primary care Health Professional Shortage Area (HPSA) for at least the last five years; a population-to-primary care provider ratio in the top 25% of all counties in the state; poverty rates above the state average; and median family incomes at least 25% below the state average.

DEADLINE: Applications are available November 1, 2001. Completed applications are due by May 31, 2002. Announcement of the selected applicants will be made by June 15, 2002.

CONTRACT PERIOD: The budget period for applications funded under this RFP will be September 1, 2002 - August 31, 2003. CONTACT PERSON: To obtain the application, please contact: David Darnell, Program Administrator, Center for Rural Health Initiatives, P.O. Drawer 1708, Austin, Texas 78767-1708, (512) 479-8891, email ddarnell@crhi.state.tx.us.

TRD-200105971
Susan Morgan
Executive Assistant
Center for Rural Health Initiatives
Filed: October 3, 2001

♦ ♦ ♦

## Coastal Coordination Council

Notice and Opportunity to Comment on Requests for Consistency Agreement/Concurrence Under the Texas Coastal Management Program

On January 10, 1997, the State of Texas received federal approval of the Coastal Management Program (CMP) (62 Federal Register pp. 1439-1440). Under federal law, federal agency activities and actions affecting the Texas coastal zone must be consistent with the CMP goals and policies identified in 31 TAC Chapter 501. As required by federal law, the public is given an opportunity to comment on the consistency of proposed activities in the coastal zone undertaken or authorized by federal agencies. Pursuant to 31 TAC §§506.25, 506.32, and 506.41, the public comment period for these activities extends 30 days from the date published on the Coastal Coordination Council web site. Requests for federal consistency review were received for the following projects(s) during the period of September 21, 2001, through September 27, 2001. The public comment period for these projects will close at 5:00 p.m. on November 2, 2001.

FEDERAL AGENCY ACTIONS:

Applicant: Williams Terminal Holdings, LP; Location: The project is located on the Houston Ship Channel at Williams Terminal Holdings, LP in the Galena Park Terminal Facility at 12901 American Petroleum Drive in Galena Park, Harris County, Texas. CCC Project No.: 01-0334-F1; Description of Proposed Action: The applicant proposes to construct and maintain a new barge dock platform for eight marine loading arms. The barge dock will also include an access walkway, an abutment, and new pipe supports. The fenderline for the new barge dock will be at the same location as the existing Barge Dock No. 2. The applicant also proposes to replace one damaged monopile mooring dolphin at ship Dock No. 2. No dredging will be required to perform the proposed work. The proposed project will not impact any wetlands and/or vegetated shallows. Type of Application: U.S.A.C.E. permit application #22476 is being evaluated under §10 of the Rivers and Harbors Act of 1899 (33 U.S.C.A. §403).

Applicant: Burlington Northern and Santa Fe Railway Company (BNSF); Location: The proposed rail line would run between Seadrift and Kamey, Texas. CCC Project No.: 01-0347-F1; Description of Proposed Action: The applicant proposes to construct and operate a new rail line, connecting the Union Carbide Corporation industrial complex at Seadrift, TX with the former Southern Pacific Transportation Company line between Placedo, TX and Port Lavaca, TX. The project would involve construction of approximately 7.8 miles of new rail line with a proposed right-of-way width of approximately 90 feet. The new rail line would convey an average of 2 trains per day and each train would have approximately 25-30 cars per train. The proposed project also includes rail/highway grade separations. Type of Application: The Surface Transportation Board has prepared a Draft Environmental Assessment for the proposed action for review. NOTE: Individual Agency Actions covered by the Environmental Impact Statement (EIS) will be subject to consistency review as ascribed by §501.15 of the Coastal Coordination Act Implementation Rules (Rev. 8/00); Title 31, Part 16.

Applicant: Robert LaDo; Location: The project is located at 2807 Lake Point Drive in Texas City, Galveston County, Texas. The project can be located on the U.S.G.S. quadrangle map entitled: Texas City, Texas. Approximate UTM Coordinates: Zone 15; Easting: 312232; Northing 3256056. CCC Project No.: 01-0350-F1; Description of Proposed Action: The applicant proposes to construct a private pier consisting of a 4-foot by 170-foot gangway, a 10-foot by 30-foot pier, and a 44-foot by 18-foot boathouse. The completed structure will total 1,772 square-feet. The structure will be 4 feet above the average water surface. The average water depth at the end of the pier is 4 feet. No vegetated shallows or wetlands will be affected by this project. Type of Application: U.S.A.C.E. permit application #22469 is being evaluated under §10 of the Rivers and Harbors Act of 1899 (33 U.S.C.A. §403).

Applicant: ExxonMobil Pipeline Company; Location: The project is located on Scott Bay, Upper San Jacinto Bay, and the Effluent Canal in Harris County, Texas. CCC Project No.: 01-0352-F1; Description of Proposed Action: The applicant proposes to abandon six sections of an existing pipeline. The reason for not removing these sections is to protect the existing shorelines and bay bottoms. Type of Application: U.S.A.C.E. permit application #22474 is being evaluated under §10 of the Rivers and Harbors Act of 1899 (33 U.S.C.A. §403).

Applicant: Kerry Milson; Location: The project is located on Caney Creek at 191 Creekside, Sargent, Matagorda County, Texas. The project can be located on the U.S.G.S. quadrangle map entitled: Sargent, Texas. Approximate UTM Coordinates: Zone 15; Easting: 240447; Northing 3187050. CCC Project No.: 01-0353-F1; Description of Proposed Action: The applicant proposes to construct a 102-linear-foot bulkhead at a distance of 2 to 12 feet from the existing shoreline. A 260 square-foot area behind the bulkhead will be filled with 1,512 cubic feet of fill. The existing shoreline has a well-developed stand of common reed (Phragmites australis) as well as other wetland plant species. Type of Application: U.S.A.C.E. permit application #22486 is being evaluated under §10 of the Rivers and Harbors Act of 1899 (33 U.S.C.A. §403) and §404 of the Clean Water Act (33 U.S.C.A. §§125-1387). NOTE: The CMP consistency review for this project may be conducted by the Texas Natural Resource Conservation Commission as part of its certification under § 401 of the Clean Water Act.

FEDERAL AGENCY ACTIONS:

Applicant: U.S. Coast Guard; Location: The project is located at Upper Morgans Point Outbound Front Range, Galveston Bay, Galveston County, Texas. The Front Light structure will be located on the new centerline extension of the Upper Morgans Point Range, approximately 3,150 feet south-southeast of the intersection between the Morgans Point Approach Range and the Upper Morgans Point Range. The Rear Light structure will be located on the new centerline extension of the Upper Morgans Point Range, approximately 600 feet south-southeast of the new Upper Morgans Point Outer Range Front Light. CCC Project No.: 01-0349-F2; Description of Proposed Action: The applicant proposes to construct two aids to navigation structures and the subsequent demolition of the existing structures in Galveston Bay, TX. Type of Application: In accordance with the requirements of Executive Order 12372, Notification of Intent is made for a proposed Coast Guard navigation structure construction and demolition project.

Pursuant to §306(d)(14) of the Coastal Zone Management Act of 1972 (16 U.S.C.A. §§1451-1464), as amended, interested parties are invited to submit comments on whether a proposed action is or is not consistent with the Texas Coastal Management Program goals and policies and whether the action should be referred to the Coastal Coordination Council for review.

Further information for the applications listed above may be obtained from Ms. Diane P. Garcia, Council Secretary, Coastal Coordination Council, 1700 North Congress Avenue, Room 617, Austin, Texas 78701-1495, or diane.garcia@glo.state.tx.us. Comments should be sent to Ms. Garcia at the above address or by fax at 512/475-0680.

TRD-200105988
Larry R. Soward
Chief Clerk, General Land Office
Coastal Coordination Council
Filed: October 3, 2001

♦ ♦ ♦

## Comptroller of Public Accounts

### Notice of Contract Award

Notice of Award: Pursuant to Chapter 2254, Chapter B, and Sections 403.011 and 403.020 Texas Government Code, the Comptroller of Public Accounts (Comptroller) announces this notice of consulting contract award.

The notice of request for proposals (RFP #123a) was published in the August 3, 2001, issue of the *Texas Register* at (26 TexReg 5852).

The consultant will assist Comptroller in conducting a management and performance review of the Aransas County Independent School District.

The contract was awarded to SoCo Consulting, Inc., 1011 Westlake Drive, Austin, Texas 78746. The total amount of this contract is not to exceed $73,092.00.

The term of the contract is September 25, 2001 through May 31, 2002. The final report is due on or before January 21, 2002.

TRD-200105972
Pamela Ponder
Deputy General Counsel for Contracts
Comptroller of Public Accounts
Filed: October 3, 2001

♦ ♦ ♦

### Notice of Contract Award

Notice of Award: Pursuant to Chapter 2254, Chapter B, and Sections 403.011 and 403.020 Texas Government Code, the Comptroller of Public Accounts (Comptroller) announces this notice of consulting contract award.

The notice of request for proposals (RFP #124a) was published in the August 3, 2001, issue of the *Texas Register* at (26 TexReg 5853).

The consultant will assist Comptroller in conducting a management and performance review of the Glen Rose Independent School District.

The contract was awarded to SDSM, Inc., P. O. Box 27619, Austin, Texas 78755. The total amount of this contract is not to exceed $75,000.00.

The term of the contract is September 25, 2001 through May 31, 2002. The final report is due on or before January 7, 2002.

TRD-200105973
Pamela Ponder
Deputy General Counsel for Contracts
Comptroller of Public Accounts
Filed: October 3, 2001

♦ ♦ ♦

## 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 and 303.009, Tex. Fin. Code.

The weekly ceiling as prescribed by Sections 303.003 and 303.009 for the period of 10/08/10/01 - 10/14/01 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 10/08/01 - 10/14/01 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-200105947
Leslie L. Pettijohn
Commissioner
Office of Consumer Credit Commissioner
Filed: October 2, 2001

♦ ♦ ♦

### Public Hearing

The Office of Consumer Credit Commissioner will conduct a public hearing beginning at: 11:00 a.m. on October 17, 2001, in the Auditorium, Houston Public Library, 500 McKinney Street, Houston, Texas 77002 to receive public comments on developing a standard format for the electronic transfer of pawnshop data to law enforcement agencies as mandated by House Bill 1763 of the 77th Legislative Session. Public comments may also address privacy issues related to reporting such data to ensure the protection of the financial information of individuals who use the services of the pawnbroker industry.

Interested persons are encouraged to attend the hearing and to present relevant and material comments. In addition persons may provide written comments on or before, November 30, 2001, to Leslie L. Pettijohn, Office of Consumer Credit Commissioner, 2601 North Lamar Boulevard, Austin, Texas 78705 or by email to info@occc.state.tx.us.

TRD-200105964
Leslie L. Pettijohn
Commissioner
Office of Consumer Credit Commissioner
Filed: October 2, 2001

♦ ♦ ♦

## Texas Department of Criminal Justice

### Notice to Bidders

The Texas Department of Criminal Justice invites bids for the Hutchins State Jail to construct an additional visitation area, Requisition Number: 696-FD-2-B008.

DESCRIPTION.

Outdoor visitation area to be increased in size and to cover the existing and new areas at the Hutchins State Jail located in Dallas, Texas. Project consists of constructing a new slab (27’0" x 50’9") toward the west and to enclose this area with a new 10’0" high (approx.) 8" CMU wall that will match the existing, complete with reinforcing pilasters to be painted to match. Both existing and new areas will be covered with a clear span, 14’ eave height pre-engineered metal building roof. The areas between the top of the CMU wall and the roof will be enclosed with a chain link fence.

REQUIREMENTS.

Contractor must have a minimum of five consecutive years of experience in the installation of the specified roofing and concrete work required and provide references for at least three projects that have been completed of a dollar value and complexity equal to or greater than the proposed project.

Please obtain bid packages at a cost of $50 on or after October 12, 2001, from the following: Edwards & Kelcey, Inc., Contact: Ron Cook, 654 North Sam Houston Parkway East, Suite 144, Houston, Texas 77060, Phone: 281-931-9920, Fax: 281-937-8929.

Range of Project: $35,000-$55,000.

TRD-200105979

Carl Reynolds
General Counsel
Texas Department of Criminal Justice
Filed: October 3, 2001

♦ ♦ ♦

## Notice to Bidders - Correction

The Texas Department of Criminal Justice invites bids for the replacement of underground wiring at the Lindsey State Jail, Jacksboro, Texas. The project consists of the installation of a duckbank around the perimeter of the sites serving all of the buildings, security camera replacement, complete replacement of all electrical conduit and conductors on every building. Included is a complete replacement of security systems and the fire alarm system in conduit. All perimeter fire alarm and security systems will be fiber optic cable installed in the ductbank, at the Lindsey State Jail, 1137 Old Post Oak Road, Jacksboro, Texas 76458. The work includes, but is not limited to, trenching, electrical, security electronics, and fiber optics installation, as further shown in the Contract Documents prepared by: Freese and Nichols, Inc., 4055 International plaza, Suite 200, Fort worth, Texas 76109.

The successful bidder will be required to meet the following requirements and submit evidence within five days after receiving notice of intent to award from the Owner:

A. Contractor must have a minimum of five consecutive years of experience as a General Contractor and provide references for at least three projects that have been completed of a dollar value and complexity equal to or greater than the proposed project.

B. Contractor must be bondable and insurable at the levels required.

All Bid Proposals must be accompanied by a Bid Bond in the amount of 5.0% of greatest amount bid. Performance and Payment Bonds in the amount of 100% of the contract amount will be required upon award of a contract. The Owner reserves the right to reject any or all bids, and to waive any informality or irregularity.

Bid Documents can be purchased from the Architect/Engineer at a cost of $150.00 (non-refundable) per set, inclusive of mailing/delivery costs, or they may be viewed at various plan rooms. Payment checks for documents should be made payable to the Architect/Engineer : Robert J. Kinkel, Freese and Nichols, Inc., 4055 International Plaza, Suite 200, Fort Worth, Texas 76109-4895; Phone: 817-735-7413; Fax: 817-735-7491.

A Pre-Bid conference will be held at 11AM on October 2, 2001, at the LINDSEY STATE JAIL, JACKSBORO, TEXAS, followed by a site-visit. ONLY ONE SCHEDULED SITE VISIT WILL BE HELD FOR REASONS OF SECURITY AND PUBLIC SAFETY; THEREFORE, BIDDERS ARE STRONGLY ENCOURAGED TO ATTEND.

Bids will be publicly opened and read at 2PM on OCTOBER 30, 2001, in the Contracts and Procurement Conference Room located in the West Hill Mall, Suite 525, Two Financial Plaza, Huntsville, Texas.

The Texas Department of Criminal Justice requires the Contractor to make a good faith effort to include Historically Underutilized Businesses (HUB's) in at least 57.2% of the total value of this construction contract award. Attention is called to the fact that not less than the minimum wage rates prescribed in the Special Conditions must be paid on these projects.

TRD-200105887

Carl Reynolds
General Counsel
Texas Department of Criminal Justice
Filed: October 1, 2001

♦ ♦ ♦

# Texas Commission for the Deaf and Hard of Hearing

## Grant Funds Available for One-Time Events

The Texas Commission for the Deaf and Hard of Hearing (TCDHH) has a total of $10,000 available for projects (1) to provide training to adults or children who are hard of hearing, late-deafened or oral deaf or to the parents of these children or (2) to provide training to professionals or service providers that will directly impact the provision of services to persons who are hard of hearing, late-deafened or oral deaf. Applicants must complete and submit the attached form to be considered for funding. Applications will be received and considered until such time as the funds are depleted and on a "first-come first-served" basis. Applications will be evaluated on the basis of the selection criteria printed elsewhere in this document.

Project Requirements

Projects are to:

A. provide training for adults or children who are hard of hearing, late-deafened or oral deaf or provide training to parents of these children; or provide training for professionals such as audiologists, hearing aid dispensers or VR counselors, who will have a direct impact on the provision of services to the target population

B. be a one-time event and not more than 1 week in duration;

seek other funds and use TCDHH funding only as a last resort (when no other funds are available)

C. acknowledge Commission funding during the event, and on publications, letterhead, materials, etc (TCDHH artwork will be supplied if necessary) and

D. provide sign-in sheets for attendees with a copy to TCDHH within 30 days after the last day of the event

Project funds can not be used for:

A. services that are legally required to be provided by other entities

B. equipment purchases

C. primarily to pay for interpreters or CART services. (projects are required to be accessible to the target population)

Priorities:

Projects may address the following topics relevant to persons who are hard of hearing, late-deafened or oral deaf:

A. workshops/training regarding legal rights, advocacy, communication strategies and communication access; assistive technology; coping strategies for improving daily living; resources and available services

B. workshops/training for professionals having direct impact on the target population, to ultimately enhance service provision to the target population by providing information about such issues as: assistive devices, resources and support available, the needs of the target population, communication strategies, hearing aid information, etc.

Additional Information:

Preference will be given to:

A. not-for-profit groups

B. projects which can provide matching funds and

C. projects which address the needs of the Spanish-speaking community

Proposals must provide estimates of the number of persons to be served.

Proposals must list other funding sources sought

Deadline for submitting proposals: Applications may be received at any time but no later than August 1, 2002.

Maximum funds available: $10,000

Maximum award amount: $2000

Project performance period: Projects funded shall provide services before September 1, 2002.

Selection Criteria:

Applications will be evaluated based on the following selection criteria:

1. The extent to which the project narrative is clear and comprehensive and explains who, what, when, where and how the training will be provided. (20 points)

2. The extent to which the proposed cost allocations are reasonable in relation to the objectives of the project. (20 points)

3. The extent to which the qualifications of project staff are sufficient for the project. (15 points)

4. The extent to which the project would serve unmet needs of the target population, or serve underserved or unserved areas. (25 points)

5. The extent to which the project has a beneficial impact on the target population or on those professionals who serve them. (20 points)

TRD-200105916
David W. Myers
Executive Director
Texas Commission for the Deaf and Hard of Hearing
Filed: October 1, 2001

♦ ♦ ♦

## Texas Education Agency

### Standard Application System Concerning Public Charter Schools, 2001-2002

Eligible Applicants. The Texas Education Agency (TEA) is requesting applications through Standard Application System (SAS) #A526 from campus charters, campus program charters, and open-enrollment charter schools as established by Texas Education Code, Chapter 12, Charters, to increase the understanding of the public charter schools model by providing financial assistance for the design and implementation of public charter schools. Applications will be mailed directly to each eligible public charter school.

Description. In accordance with the purpose of the federal Public Charter Schools Grant Program, funds may be used for post-award planning and design of the educational program, which may include: (1) refining the desired educational results and methods for measuring progress toward achieving those results; and (2) providing professional development for teachers and other staff who will work in the public charter school. Funds may also be used for the initial implementation of the charter school, which may include: (1) informing the community about the public charter school; (2) acquiring necessary equipment and educational materials and supplies; (3) acquiring or developing curriculum materials; and (4) funding other initial operational costs that cannot be met from state or local sources. Applicants must address each requirement as specified in the Request for Applications (RFA) to be considered for funding.

Dates of Project. The federal Public Charter Schools Grant Program will be implemented from January 1, 2002, to December 31, 2002. Applicants should plan for a starting date of no earlier than January 1, 2002, and an ending date of no later than December 31, 2002.

Project Amount. Each project will receive a maximum of $85,000. Project funding in any subsequent year will be based on satisfactory progress of the first-year objectives and activities and on general budget approval by the State Board of Education (SBOE) and the commissioner of education and appropriations by the U.S. Congress. This project is funded 100% from the Public Charter Schools federal funds.

The TEA is not obligated to approve an application, provide funds, or endorse any application submitted. The TEA is not committed to pay any costs before an application is approved. The TEA is not obligated to award a grant or pay any costs incurred in preparing an application.

Requesting the Application. A copy of the complete RFA #701-02-002 will be mailed to each eligible public charter school approved by the SBOE. Campus charters, campus program charters, and other interested parties may obtain complete copies of RFA#701-02-002 by writing to the: Document Control Center, Room 6-108, Texas Education Agency, William B. Travis Building, 1701 N. Congress Avenue, Austin, Texas 78701; calling (512) 463- 9304; faxing (512) 463-9811; or e-mailing dcc@tea.state.tx.us. Provide your name, complete mailing address, and telephone number, including area code. The complete RFA will also be posted on the TEA website at http://www.tea.state.tx.us./charter/. Please refer to the RFA number and title in your request.

Further Information. For clarifying information about the SAS, contact Esther Murguia Garcia, Division of Charter Schools, TEA, (512) 463-9575.

Deadline for Receipt of Applications. Applications must be received in the Document Control Center of the TEA no later than 5:00 p.m. (Central Time), Thursday, November 15, 2001, to be considered for funding.

TRD-200105974
Criss Cloudt
Associate Commissioner, Accountability Reporting and Research
Texas Education Agency
Filed: October 3, 2001

♦ ♦ ♦

## Texas General Land Office

### Notice of Contract Award for Consultant Services

In accordance with Chapter 2254, Subchapter B, and Section 2254.029, Texas Government Code, the Texas General Land Office (GLO) is publishing a notice of an award of a contract for consulting services. The Invitation for Offers of Consulting Services was published in the June 15, 2001, edition of the *Texas Register* (25 TexReg 4556).

The General Land Office (GLO) is a participant in the development and implementation of a comprehensive tide monitoring and gauging system known as the Texas Coastal Observation Network (TCOON). Other participants include the National Ocean Service (NOS), the Conrad Blucher Institute (CBI) of Texas A&M University at Corpus Christi (TAMU-CC), and the U.S. Army Corps of Engineers (COE).

The project is funded and administered through a cooperative effort of NOS, GLO, and COE. In previous years, the GLO contracted

TAMU-CC for installation and monitoring of the system and with CBI to obtain professional and technical assistance necessary to review and analyze data received from the operation of the TCOON.

The selected consultant is Briah K. Connor, Jr., 9676 Fleetwood Court, Frederick, MD 27101-7698. The total contract award is for $110,000 and the award period commenced on September 1, 2001 and will expire on August 31, 2003, unless extended or renewed by the parties, or terminated earlier.

The selected consultant shall run annual levels at each station in the respective areas of responsibility between the sensor leveling point and all bench marks at the station using electronic digital/barcode labeling system in accordance with the interim Federal Geodetic Control Subcommittee specifications and procedures for Second Order, Class I. Level runs shall be field abstracted and the benchmark descriptions shall be updated or revised using the NOS provided software. A copy of the electronic files generated, including the revised description files, shall be submitted on 3 1/2 inch floppy diskette and are due on a quarterly basis.

TRD-200105984
Larry R. Soward
Chief Clerk
Texas General Land Office
Filed: October 3, 2001

♦ ♦ ♦

## Office of the Governor

### Notice of Request for Grant Applications (RFA) for Local Law Enforcement Block Grant (LLEBG) Fund Programs

The Criminal Justice Division (CJD) of the Governor's Office is soliciting applications for Local Law Enforcement Block Grant funds from local units of government with sheriff or police departments.

Purpose: The purpose of the grants is to provide local law enforcement agencies with the opportunity to procure equipment directly related to basic law enforcement functions.

Available Funding: Local Law Enforcement Block Grant funding is made available through an LLEBG aggregate award to the Criminal Justice Division (CJD), which is the State Administrative Agency appointed by the governor to administer Texas' portion of LLEBG funds. The source of funding is an annual grant from the Office of Justice Programs. All LLEBG awards made by CJD under this RFA will have a $10,000 maximum grant award amount and will require a minimum of 10% grantee cash match.

Standards: Grantees must comply with the applicable grant management standards adopted under Title I, Part I, Chapter 3, Texas Administrative Code, which are hereby adopted by reference.

Prohibitions: Grantees may use grant funds only for the purchase equipment directly related to law enforcement functions and for the preservation of public safety. The following equipment is specifically prohibited: (1) firearms; (2) tanks/armored vehicles; (3) fixed-wing aircraft; (4) limousines; (5) real estate; and (6) yachts; (7) vehicles not primarily used for law enforcement.

Eligible Applicants: Eligible applicants include any county sheriff's department or city police department that is *neither receiving nor eligible* for a direct Local Law Enforcement Block Grant award from the Office of Justice Programs (OJP). All agencies identified as eligible for LLEBG funds from OJP are contacted by OJP directly. Any agency that has received a grant for LLEBG - Equipment Only - funds is not eligible under this RFA.

Project Period: Grant-funded projects under this specific RFA must begin on March 1, 2002 and end no later than August 31, 2002. These grants will not be eligible for extension or renewal.

Application Process: Interested applicants should call or write the regional council of governments for their county for information on application deadlines and submission requirements. Applicants may be required by a regional council to attend an application workshop prior to submitting their applications for funding. The applicant must contact the criminal justice planner at the regional council of governments for funding and workshop information. Detailed specifications are in the application kits, which is available from the regional council of governments or on the Office of the Governor's web site located at http://www.governor.state.tx.us.

Preferences: Preference will be given to applicants who will use the Local Law Enforcement Block Grant to purchase equipment directly related to law enforcement functions and for the preservation of public safety.

Closing Date for Receipt of Applications: All application deadlines are set by the regional councils of governments. Prospective applicants must contact the criminal justice planner at their regional council of governments for relevant deadlines. All applications received by the COGs are due in the Criminal Justice Division no later than January 16, 2002.

Selection Process: Applications are prioritized by the Criminal Justice Advisory Committees of the regional councils. Completed applications will be reviewed for eligibility and cost effectiveness by CJD. CJD reserves the right to renew grants for up to two additional years without the selected applications entering a competitive selection process. The Executive Director of CJD will make all final funding decisions.

Contact Person: If additional information is needed contact Taylor G. Petty in CJD at (512) 463-2822 or the criminal justice planner at the appropriate regional council of governments.

TRD-200105982
David Zimmerman
Assistant General Counsel
Office of the Governor
Filed: October 3, 2001

♦ ♦ ♦

## Texas Department of Health

### Licensing Actions for Radioactive Materials

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 | Amend-ment # | Date of Action |
|---|---|---|---|---|---|
| Houston | Houston International Cardiology | L05470 | Houston | 00 | 09/19/01 |
| Rockwall | Texas Cardiology Consultants PA | L05450 | Rockwall | 00 | 09/19/01 |
| Wichita Falls | North TX Cardiology Center LLP | L05443 | Wichita Falls | 00 | 09/19/01 |

AMENDMENTS TO LICENSES ISSUED:

| Location | Name | License # | City | Amend-ment # | Date of Action |
|---|---|---|---|---|---|
| Abilene | Hendrick Medical Center | L02433 | Abilene | 72 | 09/27/01 |
| Amarillo | Northwest Texas Healthcare System Inc | L02054 | Amarillo | 65 | 09/25/01 |
| Arlington | The University of TX at Arlington | L00248 | Arlington | 36 | 09/25/01 |
| Beeville | Christus Spohn Health System Corporation | L04510 | Beeville | 12 | 09/25/01 |
| Carrollton | Tenet Health System Hospitals Dallas Inc | L03765 | Carrollton | 35 | 09/28/01 |
| Corpus Christ | Spohn Hospital | L02495 | Corpus Christi | 67 | 09/19/01 |
| Corpus Christi | Spohn Health System Corporation | L00265 | Corpus Christi | 73 | 09/17/01 |
| Corpus Christi | The Corpus Christi Medical Center Bay Area | L04723 | Corpus Christi | 27 | 09/18/01 |
| Corpus Christi | Clinical Nuclear Services Inc | L05368 | Corpus Christi | 03 | 09/25/01 |
| Dallas | Texas Cardiology Consultants | L04997 | Dallas | 22 | 09/19/01 |
| Dallas | Tenet Health System Hospitals Dallas Inc | L02314 | Dallas | 43 | 09/28/01 |
| Dallas | Dallas Cardiology Associates PA | L04607 | Dallas | 28 | 09/21/01 |
| Denton | Columbia Medical Center of Denton Subsidiary | L02764 | Denton | 42 | 09/26/01 |
| Denton | International Isotopes Inc | L05159 | Denton | 24 | 09/27/01 |
| Edinburg | Radiology Associates of McAllen | L04512 | Edinburg | 08 | 09/17/01 |
| Edinburg | Radiology Associates of McAllen | L04512 | Edinburg | 09 | 09/27/01 |
| El Paso | The University of Texas at El Paso | L00159 | El Paso | 44 | 09/26/01 |
| Freeport | Huntsman Ethyleneamines Ltd | L05457 | Freeport | 01 | 09/21/01 |
| Ft Worth | John Peter Smith Hospital | L02208 | Ft Worth | 42 | 09/14/01 |
| Ft Worth | Ft Worth Medical Plaza Inc | L02171 | Ft Worth | 41 | 09/25/01 |
| Hondo | Medina Community Hospital | L03323 | Hondo | 14 | 09/27/01 |
| Houston | CHCA West Houston LP | L02224 | Houston | 55 | 09/27/01 |
| Houston | Hall Garcia Cardiology Associates | L05431 | Houston | 01 | 09/18/01 |
| Houston | Rice University | L04744 | Houston | 06 | 09/18/01 |
| Houston | Vital Imaging Companies | L05405 | Houston | 01 | 09/25/01 |
| Houston | Columbia/HCA Healthcare Corp | L02473 | Houston | 42 | 09/25/01 |
| Houston | DCH Health Services | L00131 | Houston | 39 | 09/25/01 |
| Houston | Cardiovascular Ventures of West Houston Inc | L04882 | Houston | 13 | 09/25/01 |
| Houston | Mallinckrodt Medical Inc | L03008 | Houston | 56 | 09/25/01 |
| Irving | Baylor Medical Center at Irving | L02444 | Irving | 39 | 09/26/01 |
| Kingsville | Texas A & M University Kingsville | L01821 | Kingsville | 30 | 09/28/01 |
| La Porte | Ohmstede Ltd | L04820 | La Porte | 02 | 09/19/01 |
| Laredo | Laredo Regional Medical Center | L02192 | Laredo | 22 | 09/25/01 |

(CONT) AMENDMENTS TO LICENSES ISSUED:

| Location | Name | License # | City | Amend-ment # | Date of Action |
|---|---|---|---|---|---|
| Lewisville | Columbia Medical Center of Lewisville Sub LP | L02739 | Lewisville | 30 | 09/21/01 |
| Littlefield | Lamb County Hospital | L04973 | Littlefield | 04 | 09/21/01 |
| Lubbock | Covenant Health System | L04881 | Lubbock | 24 | 09/19/01 |
| Lufkin | Memorial Medical Center of East Texas | L01346 | Lufkin | 67 | 09/27/01 |
| McAllen | Cardiovascular Consultants | L05126 | McAllen | 11 | 09/27/01 |
| Nederland | Beaumont Hospital Holdings Inc | L01756 | Nederland | 38 | 09/6/01 |
| Orange | Southeast Texas Cardiology Associates II LLC | L05204 | Orange | 05 | 09/24/01 |
| Plainview | Methodist Hospital Plainview | L02493 | Plainview | 21 | 09/25/01 |
| Plano | Texas Regional Heart Center | L03704 | Plano | 22 | 09/17/01 |
| Port Arthur | Beaumont Hospital Holdings Inc | L01707 | Port Arthur | 41 | 09/20/01 |
| Quitman | East Texas Medical Center | L03376 | Quitman | 11 | 09/20/01 |
| Richmond | Richmond Imaging Affiliates LTD | L04342 | Houston | 41 | 09/18/01 |
| San Antonio | Methodist Healthcare System | L03810 | San Antonio | 25 | 09/13/01 |
| San Antonio | Syncor International Corporation | L02033 | San Antonio | 91 | 09/13/01 |
| San Antonio | Methodist Healthcare System | L03810 | San Antonio | 26 | 09/19/01 |
| San Antonio | The University of Texas Health Science Center | L01279 | San Antonio | 88 | 09/27/01 |
| San Antonio | The University of TX Health Science CTR at SA | L05217 | San Antonio | 03 | 09/19/01 |
| Sherman | Wilson N Jones Memorial Hospital | L02384 | Sherman | 27 | 09/27/01 |
| Throughout TX | X-ray Inspection Inc | L05275 | Beaumont | 15 | 09/20/01 |
| Throughout TX | X-ray Inspection Inc | L05275 | Beaumont | 15 | 09/20/01 |
| Throughout TX | Phoenix Non Destructive Testing Co Inc | L04454 | Channelview | 42 | 09/24/01 |
| Throughout TX | Texas A & M University | L00448 | College Station | 107 | 09/17/01 |
| Throughout TX | Longview Inspection Inc | L01774 | Houston | 172 | 09/17/01 |
| Throughout TX | Petroleum Industry Inspectors | L04081 | Houston | 75 | 09/14/01 |
| Throughout TX | Professional Service Industries Inc | L04942 | Houston | 12 | 09/20/01 |
| Throughout TX | Baker Hughes Oilfield | L00446 | Houston | 131 | 09/20/01 |
| Throughout TX | Baker Hughes Oilfield Operations Inc | L00446 | Houston | 131 | 09/26/01 |
| Throughout TX | Big State X-ray | L02693 | Odessa | 34 | 09/19/01 |
| Throughout TX | Technical Welding Laboratory Inc | L02187 | Pasadena | 142 | 09/27/01 |
| Throughout TX | Technical Welding Laboratory Inc | L02187 | Pasadena | 140 | 09/20/01 |
| Throughout TX | Technical Welding Laboratory Inc | L02187 | Pasadena | 141 | 09/21/01 |
| Throughout TX | Earth Tech | L05449 | San Antonio | 01 | 09/12/01 |
| Throughout TX | Professional Service Industries Inc | L04946 | San Antonio | 04 | 09/20/01 |
| Waco | Providence Health Center | L01638 | Waco | 44 | 09/14/01 |
| Waco | Providence Health Center | L01638 | Waco | 45 | 09/25/01 |
| Waxahachie | Baylor Medical Center Ellis County | L04536 | Waxahachie | 19 | 09/27/01 |

RENEWALS OF LICENSES ISSUED:

| Location | Name | License # | City | Amend-ment # | Date of Action |
|---|---|---|---|---|---|
| Throughout TX | Professional Service Industries Inc | L04938 | Clute | 06 | 09/21/01 |
| Throughout TX | Professional Service Industries Inc | L03924 | Dallas | 16 | 09/21/01 |
| Throughout TX | Triple N Services Inc | L04907 | Midland | 02 | 09/20/01 |
| Throughout TX | Professional Service Industries Inc | L04946 | San Antonio | 04 | 09/20/01 |
| Throughout TX | Valero Refining Company | L02578 | Texas City | 19 | 09/27/01 |

TERMINATIONS OF LICENSES ISSUED:

| Location | Name | License # | City | Amend-ment # | Date of Action |
|---|---|---|---|---|---|
| Austin | Texas Department of Health | L01155 | Austin | 84 | 09/21/01 |
| Houston | Air Liquide America Corporation | L05041 | Houston | 02 | 09/19/01 |
| Lolita | Amtopp Corporation | L04720 | Lolita | 07 | 09/27/01 |
| Tyler | Numed Imaging Centers Inc at Tyler | L05067 | Tyler | 03 | 09/28/01 |

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 demonstrates that the person has suffered or will suffer actual injury or economic damage and, if the person is not a local government, is (a) a resident of a county, or a county adjacent to the county, in which radioactive material is or will be located, or (b) doing business or has a legal interest in land in the county or adjacent county. 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-200105970
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: October 2, 2001

♦ ♦ ♦

## Notice of Public Hearing on Proposed Immunization Rule

The Texas Department of Health (department) will hold a public hearing to take public comments on proposed rule, 25 Texas Administrative Code, §97.63, concerning the department's required immunizations for Hepatitis A. This rule was published in the August 31, 2001, issue of the *Texas Register* (26 TexReg 6541).

The hearing will be from 1:00 to 5:00 p.m., October 23, 2001, in the Main Building, Room K-100 (Auditorium), Texas Department of Health, 1100 West 49th Street, Austin, Texas 78756.

Further information may be obtained from Janie Garcia of the department's immunization division, Texas Department of Health, 1100 West 49th Street, Austin, Texas, 78756, Telephone (512) 458-7284, Extension 6430, or (800) 252-9152, or electronic mail at Janie.Garcia@tdh.state.tx.us.

TRD-200105978
Susan Steeg
General Counsel
Texas Department of Health
Filed: October 3, 2001

♦ ♦ ♦

# Texas Department of Housing and Community Affairs Manufactured Housing Division

## Notice of Administrative Hearing

**Tuesday, October 16, 2001, 1:00 p.m.**

State Office of Administrative Hearings, Stephen F. Austin Building, 1700 N Congress, 11th Floor, Suite 1100

Austin, Texas

AGENDA

Administrative Hearing before an administrative law judge of the State Office of Administrative Hearings in the matter of the complaint of the Texas Department of Housing and Community Affairs vs. Paragon Group, Inc. dba Texas Manufactured Housing to hear alleged violations of Sections 6(k), 6(l), 7(m), 14(f) and 14(j), of the Texas Manufactured Housing Standards Act and Sections 80.131(b) and 80.132(3) of the Texas Manufactured Housing Administrative Rules regarding not properly complying with the initial report and warranty orders of the Director and provide the Department with copies of completed work orders, in a timely manner, setting forth in the retail installment sales contract a down payment without actually having been received by the retailer at the time of execution of the contract, and by employing a salesperson without obtaining, maintaining, or possessing a valid salesperson's license SOAH 332-02-0267. Department MHD2000001414-W.

Contact: Jerry Schroeder, P.O. Box 12489, Austin, Texas 78711-2489, (512) 475-2894, jschroed@tdhca.state.tx.us

TRD-200105986
Daisy A. Stiner
Executive Director
Texas Department of Housing and Community Affairs Manufactured Housing Division
Filed: October 3, 2001

♦ ♦ ♦

Notice of Administrative Hearing

**Wednesday, October 17, 2001, 1:00 p.m.**

State Office of Administrative Hearings, Stephen F. Austin Building, 1700 N Congress, 11th Floor, Suite 1100

Austin, Texas

AGENDA

Administrative Hearing before an administrative law judge of the State Office of Administrative Hearings in the matter of the complaint of the Texas Department of Housing and Community Affairs vs. Clint James Luksa dba Clint J. Luksa Mobile Homes to hear alleged violations of Sections 4(d), 14(f) and 14(j) of the Texas Manufactured Housing Standards Act and Sections 80.54(a), 80.131(b) and 80.132(3) of the Texas Manufactured Housing Administrative Rules regarding not properly installing a manufactured home and not responding with corrective action in a timely manner. SOAH 332-02-0220. Department MHD2001000262-IV, MHD2001000265-IV, MHD2001000266-IV, MHD2001001768-IV, MHD2001001772-IV.

Contact: Jerry Schroeder, P.O. Box 12489, Austin, Texas 78711-2489, (512) 475-2894, jschroed@tdhca.state.tx.us

TRD-200105985

Daisy A. Stiner

Executive Director

Texas Department of Housing and Community Affairs Manufactured Housing Division

Filed: October 3, 2001

♦ ♦ ♦

## Texas Department of Insurance

### Insurer Services

Application for incorporation to the State of Texas by BALBOA LLOYDS INSURANCE COMPANY, a domestic Lloyds company. The home office is in Plano, Texas.

Application to change the name of INDEPENDENT COUNTY MUTUAL INSURANCE COMPANY to AMERICAN NATIONAL COUNTY MUTUAL INSURANCE COMPANY, a domestic fire and casualty company. The home office is in Galveston, Texas.

Application to change the name of ASSET GUARANTY INSURANCE COMPANY to RADIAN ASSET ASSURANCE INC., a foreign fire and casualty company. The home office is in New York, New York.

Application to change the name of OBAIT to ADVANTAGE HEALTH PLANS TRUST, an existing MEWA. The home office is in Oklahoma City, Oklahoma.

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-200105977

Lynda H. Nesenholtz

General Counsel and Chief Clerk

Texas Department of Insurance

Filed: October 3, 2001

♦ ♦ ♦

### Notice of Application by Small Employer Carrier to be Risk-Assuming Carrier

Notice is given to the public of the application of the listed small employer carrier to be a risk-assuming carrier 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 carrier has applied to be risk-assuming carriers:

Unicare Life & Health Insurance Company.

The application is subject to public inspection at the offices of the Texas Department of Insurance, Legal & Compliance Division - Jimmy G. Atkins, 333 Guadalupe, Hobby Tower 1, 9th Floor, Austin, Texas.

If you wish to comment on this application to be a risk-assuming carrier, 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 application, if the Commissioner is satisfied that all requirements of law have been met, the Commissioner or his designee may take action to approve the application to be a risk-assuming carrier.

TRD-200105944

Lynda H. Nesenholtz

General Counsel and Chief Clerk

Texas Department of Insurance

Filed: October 1, 2001

♦ ♦ ♦

### Third Party Administrator Application

The following third party administrator (TPA) application has been filed with the Texas Department of Insurance and is under consideration.

Application for admission to Texas of Healthcare Assurance Corporation, a foreign third party administrator. The home office is Knoxville, Tennessee.

Any objections must be filed within 20 days after this notice was filed with the Secretary of State, addressed to the attention of Charles M. Waits, MC 107-5A, 333 Guadalupe, Austin, Texas 78714-9104.

TRD-200105965

Lynda H. Nesenholtz

General Counsel and Chief Clerk

Texas Department of Insurance

Filed: October 2, 2001

♦ ♦ ♦

## Texas Natural Resource Conservation Commission

### Notice of Opportunity to Comment on Default Orders of Administrative Enforcement Actions

The Texas Natural Resource Conservation Commission (TNRCC or commission) staff is providing an opportunity for written public comment on the listed Default Order (DO). The TNRCC staff proposes a DO when the staff has sent an Executive Director's Preliminary Report and Petition (EDPRP) to an entity outlining the alleged violations; the proposed penalty; and the proposed technical requirements necessary to bring the entity back into compliance, and the entity fails to request a hearing on the matter within 20 days of its receipt of the EDPRP. Similar to the procedure followed with respect to Agreed Orders entered into by the executive director of the TNRCC pursuant to Texas Water Code, §7.075, this notice of the proposed order and the opportunity to comment is published in the *Texas Register* no later than the 30th day before the date on which the public comment period closes, which in this case is **November 12, 2001**. The TNRCC will consider any written comments received and the TNRCC may withdraw or withhold approval of a DO if a comment discloses facts or considerations that indicate that a proposed DO is inappropriate, improper, inadequate, or inconsistent with the requirements of the statutes and rules within the TNRCC's jurisdiction, or the TNRCC's orders and permits issued pursuant to the TNRCC's regulatory authority. Additional notice of changes to a proposed DO is not required to be published if those changes are made in response to written comments.

A copy of the proposed DO is available for public inspection at both the TNRCC's Central Office, located at 12100 Park 35 Circle, Building A, 3rd Floor, Austin, Texas 78753, (512) 239-3400 and at the applicable Regional Office listed as follows. Comments about the DO should be sent to the attorney designated for the DO at the TNRCC's Central Office at P.O. Box 13087, MC 175, Austin, Texas 78711-3087 and must be **received by 5:00 p.m. on November 26, 2001**. Comments may also be sent by facsimile machine to the attorney at (512) 239-3434. The TNRCC attorneys are available to discuss the DO and/or the comment procedure at the listed phone numbers; however, comments on the DO should be submitted to the TNRCC in **writing**.

(1) COMPANY: Haden E. Archer; DOCKET NUMBER: 2000-0488-OSI-E; TNRCC ID NUMBER: OS2959; LOCATION: P. O. Box 118, Iola, Grimes County, Texas; TYPE OF FACILITY: on-site sewage facility installer (OSSF); RULES VIOLATED: Texas Health and Safety Code (THSC), §366.051(c), by failing to verify proof of a permit; THSC, §366.054, by failing to notify the permitting authority; 30 TAC §285.5, by failing to submit the required planning materials for an OSSF installation; §285.58(a)(3), by failing to obtain the necessary authorization before the installation; §285.58(a)(11), by failing to contact the permitting authority for required inspections; §285.30(b)(5), (f), (i)(3) and §285.58(a)(6), THSC, §366.004, by failing to install the standard absorptive drain fields in suitable site conditions; PENALTY: $3,125; STAFF ATTORNEY: Joshua M. Olszewski, Litigation Division, MC 175, (512) 239-3400; REGIONAL OFFICE: Houston Regional Office, 5425 Polk Ave., Ste. H, Houston, Texas 77023-1486, (713) 767-3500.

TRD-200105957
Paul C. Sarahan
Director, Litigation Division
Texas Natural Resource Conservation Commission
Filed: October 2, 2001

♦ ♦ ♦

## Notice of Opportunity to Comment on Settlement Agreements of Administrative Enforcement Actions

The Texas Natural Resource Conservation Commission (TNRCC or commission) staff is providing an opportunity for written public comment on the listed Agreed Orders (AOs) pursuant to Texas Water Code (the Code), §7.075, which requires that the TNRCC may not approve these AOs unless the public has been provided an opportunity to submit written comments. Section 7.075 requires that notice of the proposed orders and of the opportunity to comment must be published in the *Texas Register* no later than the 30th day before the date on which the public comment period closes, which in this case is **November 12, 2001**. Section 7.075 also requires that the TNRCC promptly consider any written comments received and that the TNRCC may withhold approval of an AO if a comment discloses facts or considerations that indicate the proposed AO is inappropriate, improper, inadequate, or inconsistent with the requirements of the Code, the Texas Health and Safety (THSC), and/or the Texas Clean Air Act (the Act). Additional notice is not required if changes to an AO are made in response to written comments.

A copy of each of the proposed AOs is available for public inspection at both the TNRCC's Central Office, located at 12100 Park 35 Circle, Building C, 1st Floor, Austin, Texas 78753, (512) 239-1864 and at the applicable Regional Office listed as follows. Written comments about these AOs should be sent to the enforcement coordinator designated for each AO at the TNRCC's Central Office at P.O. Box 13087, Austin, Texas 78711-3087 and must be **received by 5:00 p.m. on November 12, 2001**. Written comments may also be sent by facsimile machine to the enforcement coordinator at (512) 239-2550. The TNRCC enforcement coordinators are available to discuss the AOs and/or the comment procedure at the listed phone numbers; however, §7.075 provides that comments on the AOs should be submitted to the TNRCC in **writing**.

(1) COMPANY: Action Oil Services, Inc.; DOCKET NUMBER: 2001-0354-AIR-E; IDENTIFIER: Air Account Number JE-0906-G and Used Oil Handler Registration Number A-85285; LOCATION: Beaumont, Jefferson County, Texas; TYPE OF FACILITY: used oil recovery and storage; RULE VIOLATED: 30 TAC §§111.201, 324.4(2)(V)(ii), 324.41(1), 328.23(a) and (b), 330.5, Agreed Order Docket Number 1998-0852-MSW-E, and THSC, §371.041 and §382.085(b), by failing to comply with the rules of outdoor burning and pay the administrative penalty assessed by Agreed Order 1998-0852-MSW-E; PENALTY: $1,000; ENFORCEMENT COORDINATOR: Susan Kelly, (409) 898-3838; REGIONAL OFFICE: 3870 Eastex Freeway, Suite 110, Beaumont, Texas 77703-1892, (409) 898-3838.

(2) COMPANY: Alapsara Inc. dba Almeda Food Mart; DOCKET NUMBER: 2001-0354-PST- E; IDENTIFIER: Petroleum Storage Tank (PST) Facility Identification Number 0029239; LOCATION: Houston, Harris County, Texas; TYPE OF FACILITY: convenience store with retail sales of gasoline; RULE VIOLATED: 30 TAC §334.50(b)(1)(A), (2)(A)(i)(III) and (ii), (d)(4)(A)(i) and (ii)(II), and the Code, §26.3475(c)(1), by failing to provide proper release detection; conduct annual tightness testing; conduct annual performance testing; conduct inventory control in combination with automatic tank gauging; and put the automatic tank gauge system into test mode; 30 TAC §334.48(c), by failing to conduct monthly inventory control; 30 TAC §334.7(d)(3), by failing to amend underground storage tank registration; and 30 TAC §334.105(a) and (b) (now 30 TAC §37.875(a) and (b)), by failing to provide proof of financial assurance; PENALTY: $5,040; ENFORCEMENT COORDINATOR: Rebecca Johnson, (713) 767-3500; REGIONAL OFFICE: 5425 Polk Avenue, Suite H, Houston, Texas 77023-1486, (713) 767-3500.

(3) COMPANY: Robert Staton dba Allied Recycling Services; DOCKET NUMBER: 2001-0620- MSW-E; IDENTIFIER: Used Oil Handler Registration Number A85545; LOCATION: Seguin, Guadalupe County, Texas; TYPE OF FACILITY: used oil and used oil filter transfer, treatment, and storage; RULE VIOLATED: 30 TAC §37.2011 and §324.222, by failing to provide financial assurance for the active area of the facility; PENALTY: $200; ENFORCEMENT COORDINATOR: Tel Croston, (512) 239-5717; REGIONAL OFFICE: 14250 Judson Road, San Antonio, Texas 78233- 4480, (210) 490-3096.

(4) COMPANY: American Retirement Corporation dba Homewood Residence at Shavano Park; DOCKET NUMBER: 2001-0727-EAQ-E;

IDENTIFIER: Edwards Aquifer (EAQ) Protection Program Project Number 1543.00; LOCATION: San Antonio, Bexar County, Texas; TYPE OF FACILITY: assisted living; RULE VIOLATED: 30 TAC §213.4(a), by failing to obtain approval prior to placement of one 500 gallon aboveground petroleum storage tank on the recharge zone; PENALTY: $800; ENFORCEMENT COORDINATOR: Rebecca Clausewitz, (210) 490-3096; REGIONAL OFFICE: 14250 Judson Road, San Antonio, Texas 78233-4480, (210) 490-3096.

(5) COMPANY: Aztec Rental Partners, LLC; DOCKET NUMBER: 2001-0617-SLG-E; IDENTIFIER: Sludge Transporter Registration Number 22817; LOCATION: near Lolita, Jackson County, Texas; TYPE OF FACILITY: sludge and septic service; RULE VIOLATED: the Code, §26.121, by failing to prevent an unauthorized discharge of sewage; and 30 TAC §312.146 and the Code, §26.039, by failing to notify the commission of an unauthorized discharge; PENALTY: $800; ENFORCEMENT COORDINATOR: Gary McDonald, (361) 825-3100; REGIONAL OFFICE: 6300 Ocean Drive, Suite 1200, Corpus Christi, Texas 78412-5503, (361) 825-3100.

(6) COMPANY: Alfredo Baeza dba Alfredo Baeza Septic Tank Pumping; DOCKET NUMBER: 2001-0229-SLG-E; IDENTIFIER: Sludge Transporter Registration Number 21614; LOCATION: Presidio, Presidio County, Texas; TYPE OF FACILITY: sludge transporter; RULE VIOLATED: 30 TAC §312.143 and the Code, §26.121, by failing to properly dispose of grease trap waste; 30 TAC §312.144(a) and (f), by failing to prominently mark and identify the truck used to transport grease trap waste and the valves and/or ports on the tanks; 30 TAC §312.145(a) and (b)(4), by failing to maintain a record of each individual collection and deposit in the form of trip tickets and accurately report amount and type of waste collected and delivered; PENALTY: $5,200; ENFORCEMENT COORDINATOR: Gary Shipp, (806) 796-7092; REGIONAL OFFICE: 401 East Franklin Avenue, Suite 560, El Paso, Texas 79901-1206, (915) 834-4949.

(7) COMPANY: Bayer Water System, Inc.; DOCKET NUMBER: 2001-0622-PWS-E; IDENTIFIER: Public Water Supply (PWS) Number 1010212 and Certificate of Convenience and Necessity (CCN) Number 12281; LOCATION: Spring, Harris County, Texas; TYPE OF FACILITY: public water supply; RULE VIOLATED: 30 TAC §291.21(c)(7) and §291.93(2)(A), and the Code, §13.136(a), by failing to ensure that its tariff includes an approved drought contingency plan; and 30 TAC §288.30(3)(B) and the Code, §13.132(a)(1), by failing to make its adopted drought contingency plan available for inspection; PENALTY: $125; ENFORCEMENT COORDINATOR: Tel Croston, (512) 239-5717; REGIONAL OFFICE: 5425 Polk Avenue, Suite H, Houston, Texas 77023-1486, (713) 767-3500.

(8) COMPANY: Mr. Ha Van Nguyen dba Burnet Hills Mobile Home Park and Windy Hills Mobile Home Park; DOCKET NUMBER: 2001-0228-PWS-E; IDENTIFIER: PWS Numbers 0270042 and 0270090; LOCATION: Burnet, Burnet County, Texas; TYPE OF FACILITY: public water supply; RULE VIOLATED: 30 TAC §290.106(a)(1) (now 30 TAC §290.109(c)(1)(A)), by failing to have a written sample siting plan; 30 TAC §290.46(f)(2), (i), (k), (n), and (p) (now 30 TAC §290.46(n)(2)), by failing to maintain records of the disinfectant residual tests, adopt a plumbing ordinance, regulations, or service agreement, construct a water line connecting the water systems without receiving prior approval, maintain maps of the water distribution systems, maintain records of the annual inspections of the ground storage tanks, and maintain records of the annual inspections of the pressure tanks; 30 TAC §290.39(h)(1), by constructing two ground storage tanks without providing prior notification; 30 TAC §290.41(c)(1)(F) and (3)(B), by failing to obtain sanitary control easements for the water wells and by failing to have the well casing extend at least 18 inches above the finished floor; 30 TAC §290.45(b)(1)(B)(i), Agreed Order Number 1998-1167-PWS-E, and the Code, §341.0315(c), by failing to provide the minimum required well capacity at the Burnet Hills and Windy Hills water systems; 30 TAC §291.21(c)(7) and §291.93(2)(A), and the Code, §13.136(a), by failing to ensure that the Burnet Hills water system's tariff includes an approved drought contingency plan; and 30 TAC §288.30(3)(B) and the Code, §13.132(a)(1), by failing to make Burnet Hills water system's adopted drought contingency plan available for inspection; PENALTY: $4,563; ENFORCEMENT COORDINATOR: Larry King, (512) 339-2929; REGIONAL OFFICE: 1921 Cedar Bend Drive, Suite 150, Austin, Texas 78758-5336, (512) 339-2929.

(9) COMPANY: Dixie Chemical Company, Inc.; DOCKET NUMBER: 2001-0435-IHW-E; IDENTIFIER: Solid Waste Registration Number 30314; LOCATION: Pasadena, Harris County, Texas; TYPE OF FACILITY: organic chemical manufacturing; RULE VIOLATED: 30 TAC §335.62 and §335.504, and 40 Code of Federal Regulations (CFR) §262.11, by failing to conduct hazardous waste determinations; 30 TAC §335.4 and the Code, §26.121, by failing to prevent unauthorized discharge of hazardous waste; 30 TAC §335.431 and 40 CFR §268.1(a)(4) and §268.40, by failing to meet treatment standards for hazardous waste constituents; and 30 TAC §335.69(a)(1)(B) and §335.112(a)(9), and 40 CFR §262.34(a)(1)(ii) and §265.193(a)(1), by failing to provide secondary containment for a less than 90 days hazardous waste tank; PENALTY: $44,000; ENFORCEMENT COORDINATOR: Catherine Sherman, (713) 767-3500; REGIONAL OFFICE: 5425 Polk Avenue, Suite H, Houston, Texas 77023-1486, (713) 767-3500.

(10) COMPANY: E.I. Du Pont De Nemours and Company, Inc.; DOCKET NUMBER: 2001- 0722-AIR-E; IDENTIFIER: Air Account Number OC-0007-J; LOCATION: Orange, Orange County, Texas; TYPE OF FACILITY: petrochemical plant; RULE VIOLATED: 30 TAC §101.4 and THSC, §382.085(a) and (b), by allegedly having unauthorized emissions which resulted in nuisance conditions; PENALTY: $8,000; ENFORCEMENT COORDINATOR: Laura Clark, (409) 898-3838; REGIONAL OFFICE: 3870 Eastex Freeway, Suite 110, Beaumont, Texas 77703-1892, (409) 898-3838.

(11) COMPANY: Evans Systems, Inc.; DOCKET NUMBER: 2001-0641-PST-E; IDENTIFIER: PST Facility Identification Number 33625; LOCATION: League City, Galveston County, Texas; TYPE OF FACILITY: convenience store with retail sales of gasoline; RULE VIOLATED: 30 TAC §115.246(4) and THSC, §382.085(b), by failing to maintain proof of attendance and completion of Stage II training; and 30 TAC §115.245(2) and THSC, §382.085(b), by failing to successfully perform the annual pressure decay test; PENALTY: $2,500; ENFORCEMENT COORDINATOR: Bill Davis, (512) 239-6793; REGIONAL OFFICE: 5425 Polk Avenue, Suite H, Houston, Texas 77023-1486, (713) 767-3500.

(12) COMPANY: Hardy Oaks, Ltd.; DOCKET NUMBER: 2001-0728-EAQ-E; IDENTIFIER: EAQ Protection Program Project Number 1291.00; LOCATION: San Antonio, Bexar County, Texas; TYPE OF FACILITY: commercial office space; RULE VIOLATED: 30 TAC §213.4(k), Water Pollution Abatement Plan for Project Number 1291.00, and the Code, §26.121(a)(3), by failing to adhere to Special Condition Number Six of the Water Pollution Abatement Plan; PENALTY: $1,250; ENFORCEMENT COORDINATOR: Rebecca Clausewitz, (210) 490-3096; REGIONAL OFFICE: 14250 Judson Road, San Antonio, Texas 78233-4480, (210) 490-3096.

(13) COMPANY: Theo Hybner; DOCKET NUMBER: 2001-0707-MSW-E; IDENTIFIER: Unauthorized Tire Site Number COT0002; LOCATION: Shiner, Lavaca County, Texas; TYPE OF FACILITY: unauthorized tire facility; RULE VIOLATED: 30 TAC §328.57(c)(1) and(3), by failing to obtain a scrap tire transporter registration and transport scrap tire to an authorized site; and 30 TAC §328.60(a), by

failing to obtain a scrap tire storage site registration prior to storing more than 500 scrap tires; PENALTY: $2,400; ENFORCEMENT COORDINATOR: Carol McGrath, (361) 825-3100; REGIONAL OFFICE: 6300 Ocean Drive, Suite 1200, Corpus Christi, Texas 78412-5503, (361) 825-3100.

(14) COMPANY: City of Katy; DOCKET NUMBER: 2001-0199-MWD-E; IDENTIFIER: Texas Pollutant Discharge Elimination System (TPDES) Permit Number 10706-001; LOCATION: Katy, Fort Bend County, Texas; TYPE OF FACILITY: wastewater treatment; RULE VIOLATED: 30 TAC §305.125(1), TPDES Permit Number 10706-001, and the Code, §26.121, by allowing discharges of wastewater that did not comply with permitted limits; PENALTY: $11,250; ENFORCEMENT COORDINATOR: Brian Lehmkuhle, (512) 238-4482; REGIONAL OFFICE: 5425 Polk Avenue, Suite H, Houston, Texas 77023-1486, (713) 767-3500.

(15) COMPANY: La Joya Water Supply Corporation; DOCKET NUMBER: 2001-0573-PWS-E; IDENTIFIER: PWS Number 1080022; LOCATION: Palmview, Hidalgo County, Texas; TYPE OF FACILITY: public water supply; RULE VIOLATED: 30 TAC §290.45(b)(2)(E) and (G), and THSC, §341.0315(c), by failing to provide a total storage capacity and provide an elevated storage capacity; 30 TAC §290.42(d)(2) and (5), by failing to prevent the cross-connection between the post chlorinated water line and another conduit carrying raw water and provide a flow measuring device; 30 TAC §290.121(a), by failing to provide a copy of the monitoring plan; and 30 TAC §290.46(m), by failing to provide maintenance to the east clarifier; PENALTY: $5,863; ENFORCEMENT COORDINATOR: Sandra Hernandez Alanis, (956) 425-6010; REGIONAL OFFICE: 1804 West Jefferson Avenue, Harlingen, Texas 78550-5247, (956) 425-6010.

(16) COMPANY: Mr. John Martinec dba Lake Worth Mobile Home Park; DOCKET NUMBER: 2001-0448-PWS-E; IDENTIFIER: PWS Number 2200136; LOCATION: Fort Worth, Tarrant County, Texas; TYPE OF FACILITY: public water supply; RULE VIOLATED: 30 TAC §290.46(e)(1) and (m)(1), by failing to have the system under direct supervision of a certified waterworks operator and conduct annual inspections of pressure tanks; 30 TAC §290.45(b)(1)(A)(ii) and THSC, §341.0315(c), by failing to provide a pressure tank capacity of 50 gallons per connection; 30 TAC §290.41(c)(3)(A), (B), (F), (M), and (N), by failing to provide well completion data, extend the well casing 18 inches above the natural ground level, provide a sanitary control easement, and provide a sampling tap and a flow meter on the well pump discharge line; PENALTY: $2,550; ENFORCEMENT COORDINATOR: Judy Fox, (817) 588-5800; REGIONAL OFFICE: 2301 Gravel Drive, Fort Worth, Texas 76118-6951, (817) 588-5800.

(17) COMPANY: Mr. Domingo Morales dba Morales Plating; DOCKET NUMBER: 2001-0197- AIR-E; IDENTIFIER: Air Account Number KB-0193-S; LOCATION: Forney, Kaufman County, Texas; TYPE OF FACILITY: decorative chromium plating; RULE VIOLATED: 30 TAC §§106.376, 116.110(a), and 113.190, and THSC, §382.085(b), by failing to maintain records to show compliance with 40 CFR Part 63, Subpart N, to submit a notification of compliance status and prepare and maintain a formal ongoing compliance status report; and 30 TAC §113.100 and §113.190, and THSC, §382.085(b), by failing to maintain records for continuous compliance monitoring or perform initial performance testing and prepare a formal operation and maintenance plan; PENALTY: $7,200; ENFORCEMENT COORDINATOR: Jorge Ibarra, (817) 588-5800; REGIONAL OFFICE: 2301 Gravel Drive, Fort Worth, Texas 76118-6951, (817) 588-5800.

(18) COMPANY: Norton Company; DOCKET NUMBER: 2001-0586-AIR-E; IDENTIFIER: Air Account Number EF-0012-C; LOCATION: Stephenville, Erath County, Texas; TYPE OF FACILITY: abrasive belt manufacturing; RULE VIOLATED: 30 TAC §122.145(2) and §122.146, and THSC, §382.085(b), by failing to submit the required deviation reports and annual compliance certifications; PENALTY: $3,600; ENFORCEMENT COORDINATOR: Jorge Ibarra, (817) 588-5800; REGIONAL OFFICE: 2301 Gravel Drive, Fort Worth, Texas 76118-6951, (817) 588-5800.

(19) COMPANY: Ms. Upinder K. Singh dba One Stop & Go; DOCKET NUMBER: 2000- 1032-PST-E; IDENTIFIER: PST Facility Identification Number 0044668; LOCATION: Euless, Tarrant County, Texas; TYPE OF FACILITY: convenience store with retail sales of gasoline; RULE VIOLATED: 30 TAC §115.242(9) and THSC, §382.085(b), by failing to have the required operating instructions and information posted on the dispensers; 30 TAC §115.245(2) and THSC, §382.085(b), by failing to successfully conduct the annual pressure decay test; 30 TAC §115.246(4) and THSC, §382.085(b), by failing to provide proof of attendance and completion of training; 30 TAC §334.50(b)(2)(A)(i)(III) and (ii)(I), and THSC, §26.3475, by failing to perform annual performance test on the line leak detector and perform a tightness test for the pressurized piping; and 30 TAC §334.48(c), by failing to conduct inventory volume measurements; PENALTY: $13,125; ENFORCEMENT COORDINATOR: Judy Fox, (817) 588-5800; REGIONAL OFFICE: 2301 Gravel Drive, Fort Worth, Texas 76118-6951, (817) 588-5800.

(20) COMPANY: Silica Products, Inc.; DOCKET NUMBER: 2001-0587-AIR-E; IDENTIFIER: Air Account Number BL-0687-A; LOCATION: Freeport, Brazoria County, Texas; TYPE OF FACILITY: synthetic fused silica glass manufacturing; RULE VIOLATED: 30 TAC §116.115(c), TNRCC Air Permit Number 35978, and THSC, §382.085(b), by failing to certify that the continuous emissions monitoring system unit meets performance specifications; and 30 TAC §101.20(1) and 40 CFR §60.113b(c), TNRCC Air Permit Number 35978, and the THSC, §382.085(b), by failing to submit an operating plan; PENALTY: $5,400; ENFORCEMENT COORDINATOR: Trina Grieco, (713) 767-3500; REGIONAL OFFICE: 5425 Polk Avenue, Suite H, Houston, Texas 77023-1486, (713) 767-3500.

(21) COMPANY: Zaki Niazi dba Snappy Mart No. 6; DOCKET NUMBER: 2001-0680-PWS-E; IDENTIFIER: PWS Number 1700557; LOCATION: Conroe, Montgomery County, Texas; TYPE OF FACILITY: public water supply; RULE VIOLATED: 30 TAC §290.106(a) and (e), and §290.103(5) (now 30 TAC §290.109(c)(2) and (g), and §290.122(c)), by failing to collect and submit routine monthly water samples for bacteriological analysis and provide public notice; and 30 TAC §290.51, by failing to pay public health service fees; PENALTY: $938; ENFORCEMENT COORDINATOR: Kimberly McGuire, (512) 239-4761; REGIONAL OFFICE: 5425 Polk Avenue, Suite H, Houston, Texas 77023-1486, (713) 767-3500.

(22) COMPANY: City of Snyder; DOCKET NUMBER: 2001-0712-PST-E; IDENTIFIER: PST Facility Identification Number 10734; LOCATION: Snyder, Scurry County, Texas; TYPE OF FACILITY: city warehouse; RULE VIOLATED: 30 TAC §334.50(b)(1)(A) and the Code, §26.3475, by failing to monitor underground storage tanks; and 30 TAC §330.602(a), by failing to pay municipal solid waste fees; PENALTY: $2,000; ENFORCEMENT COORDINATOR: Carolyn Easley, (915) 698-9674; REGIONAL OFFICE: 1977 Industrial Boulevard, Abilene, Texas 79602-7833, (915) 698-9674.

(23) COMPANY: South-Tex Concrete, Inc.; DOCKET NUMBER: 2001-0414-AIR-E; IDENTIFIER: Air Account Numbers 92-2093-H and 92-0482-G; LOCATION: Sullivan City, Hidalgo County, Texas; TYPE OF FACILITY: concrete batch plants; RULE VIOLATED: 30 TAC §116.115(c), Permit Number 22093, and THSC, §382.085(b),

by failing to operate under the allowed maximum annual throughput of 15,000 cubic yards per year; operate the facility with water sprays; install a visible and/or audible warning device in the fly ash and cement silos; have a truck drop batch point controlled by a water fog ring; comply with all record keeping requirements; maintain a file and make available copies of material safety data sheets; maintain a copy of Permit Numbers 22093 and 20649 at the plant and made available upon request; maintain permanent in-plant roads; have the cement weigh hopper vented to a fabric filter; load rotary mix trucks through a discharge spout equipped with a water fog ring; and maintain a water truck on-site for the purpose of watering plant roads; PENALTY: $14,400; ENFORCEMENT COORDINATOR: Sandra Hernandez, (956) 425- 6010; REGIONAL OFFICE: 1804 West Jefferson Avenue, Harlingen, Texas 78550-5247, (956) 425-6010.

(24) COMPANY: Upper Valley Enterprises, Inc. dba Shorty's Food Marts; DOCKET NUMBER: 2001-0545-AIR-E; IDENTIFIER: Air Account Number EE-1957-I; LOCATION: Canutillo, El Paso County, Texas; TYPE OF FACILITY: convenience food store; RULE VIOLATED: 30 TAC §114.100(a) and THSC, §382.085(b), by failing to comply with the 2.7% by weight oxygenate content; PENALTY: $600; ENFORCEMENT COORDINATOR: John Mead, (512) 239-6010; REGIONAL OFFICE: 401 East Franklin Avenue, Suite 560, El Paso, Texas 79901-1206, (915) 834-4949.

(25) COMPANY: Mr. Mark Taylor; DOCKET NUMBER: 2001-0317-LII-E; IDENTIFIER: Landscape Irrigator License Number 6369; LOCATION: Carrollton, Dallas County, Texas; TYPE OF FACILITY: landscape irrigation system; RULE VIOLATED: 30 TAC §344.72, by failing to design and install an irrigation system in a manner which promotes water conservation; 30 TAC §344.77(a), by failing to design and install an irrigation system which meets the manufacturer's maximum recommended spray head spacing; and 30 TAC §344.94(b), by failing to include the statement: "Irrigation in Texas is regulated by the Texas Natural Resource Conservation Commission, P.O. Box 13087, Austin, Texas 78711-3087" in a written contract to install an irrigation system; PENALTY: $220; ENFORCEMENT COORDINATOR: Tom Greimel, (512) 239-5690; REGIONAL OFFICE: 2301 Gravel Drive, Fort Worth, Texas 76118-6951, (817) 588-5800.

(26) COMPANY: Tejas Gas Pipeline, L.P.; DOCKET NUMBER: 2001-0453-AIR-E; IDENTIFIER: Air Account Number HG-1391-L; LOCATION: Pasadena, Harris County, Texas; TYPE OF FACILITY: natural gas transmission; RULE VIOLATED: 30 TAC §122.146(2) and THSC, §382.085(b), by failing to submit annual compliance certification; and 30 TAC §122.145(2)(B) and THSC, §382.085(b), by failing to submit deviation reports; PENALTY: $1,800; ENFORCEMENT COORDINATOR: Catherine Sherman, (713) 767-3500; REGIONAL OFFICE: 5425 Polk Avenue, Suite H, Houston, Texas 77023-1486, (713) 767-3500.

(27) COMPANY: U.S. Liquids of Houston, L.L.C.; DOCKET NUMBER: 2001-0040-AIR-E; IDENTIFIER: Air Account Number HG-5304-E; LOCATION: Houston, Harris County, Texas; TYPE OF FACILITY: dewatering plant; RULE VIOLATED: 30 TAC §101.4, by failing to prevent odors from leaving the property; PENALTY: $2,500; ENFORCEMENT COORDINATOR: Mike Meyer, (512) 239-4492; REGIONAL OFFICE: 5425 Polk Avenue, Suite H, Houston, Texas 77023- 1486, (713) 767-3500.

(28) COMPANY: Wagner Oil Company; DOCKET NUMBER: 2001-0733-AIR-E; IDENTIFIER: Air Account Number AG-0012-N and Operating Permit Number O-00509; LOCATION: Jourdanton, Atascosa County, Texas; TYPE OF FACILITY: natural gas compressor station; RULE VIOLATED: 30 TAC §122.46(2) and THSC, §382.085(b), by failing to submit an annual compliance certification; and 30 TAC §122.45(2)(C) and THSC, §382.085(b), by failing to submit a deviation report; PENALTY: $1,800; ENFORCEMENT COORDINATOR: Sandy VanCleave, (512) 239-0667; REGIONAL OFFICE: 14250 Judson Road, San Antonio, Texas 78233-4480, (210) 490-3096.

(29) COMPANY: Waterco Incorporated dba Bell Water Company; DOCKET NUMBER: 2001- 0562-PWS-E; IDENTIFIER: PWS Number 2280034 and CCN Number 10130; LOCATION: Pasadena, Harris County, Texas; TYPE OF FACILITY: public water supply; RULE VIOLATED: 30 TAC §291.21(c)(7) and §291.93(2)(A), and the Code, §13.136(a), by failing to ensure that its tariff includes an approved drought contingency plan; and 30 TAC §288.30(3)(B) and the Code, §13.132(a)(1), by failing to make its adopted drought contingency plan available for inspection; PENALTY: $125; ENFORCEMENT COORDINATOR: Sunday Udoetok, (512) 239-0739; REGIONAL OFFICE: 5425 Polk Avenue, Suite H, Houston, Texas 77023-1486, (713) 767-3500.

(30) COMPANY: City of Whitney; DOCKET NUMBER: 2000-1426-MWD-E; IDENTIFIER: TPDES Permit Number 11408-002; LOCATION: Whitney, Hill County, Texas; TYPE OF FACILITY: wastewater treatment; RULE VIOLATED: 30 TAC §305.125(1), TPDES Permit Number 11408-002, and the Code, §26.121, by failing to comply with total suspended solids, five-day carbonaceous biochemical oxygen demand, dissolved oxygen, ammonia nitrogen, and daily average flow; PENALTY: $5,000; ENFORCEMENT COORDINATOR: Pamela Campbell, (512) 239-4493; REGIONAL OFFICE: 6801 Sanger Avenue, Suite 2500, Waco, Texas 76710-7826, (254) 751-0335.

TRD-200105946
Paul C. Sarahan
Director, Litigation Division
Texas Natural Resource Conservation Commission
Filed: October 2, 2001

♦ ♦ ♦

## Notice of Opportunity to Comment on Settlement Agreements of Administrative Enforcement Actions

The Texas Natural Resource Conservation Commission (TNRCC or commission) staff is providing an opportunity for written public comment on the listed Agreed Order (AO) pursuant to Texas Water Code (TWC), §7.075. Section 7.075 requires that before the commission may approve the AO, the commission shall allow the public an opportunity to submit written comments on the proposed AO. Section 7.075 requires that notice of the opportunity to comment must be published in the *Texas Register* no later than the 30th day before the date on which the public comment period closes, which in this case is **November 12, 2001**. Section 7.075 also requires that the commission promptly consider any written comments received and that the commission may withdraw or withhold approval of an AO if a comment discloses facts or considerations that the consent is inappropriate, improper, inadequate, or inconsistent with the requirements of the statutes and rules within the TNRCC's orders and permits issued pursuant to the TNRCC's regulatory authority. Additional notice of changes to a proposed AO is not required to be published if those changes are made in response to written comments.

A copy of the proposed AO is available for public inspection at both the TNRCC's Central Office, located at 12100 Park 35 Circle, Building A, 3rd Floor, Austin, Texas 78753, (512) 239-3400 and at the applicable Regional Office listed as follows. Comments about the AO should be sent to the attorney designated for the AO at the TNRCC's Central Office at P.O. Box 13087, MC 175, Austin, Texas 78711-3087 and must be **received by 5:00 p.m. on November 26, 2001**. Comments may also be sent by facsimile machine to the attorney at (512) 239-3434. The TNRCC attorneys are available to discuss the AO and/or the comment procedure at the listed phone numbers; however, §7.075 provides that comments on the AO should be submitted to the TNRCC in **writing**.

(1) COMPANY: Doyle Wood dba Martin Springs Dairy; DOCKET NUMBER: 1999-1490-AGR-E; TNRCC ID NUMBER: 0003274; LOCATION: 1/4 mile south of Farm-to-Market Road 2560 and Highway 11 near Sulphur Springs, Hopkins County, Texas; TYPE OF FACILITY: dairy; RULES VIOLATED: 30 TAC §321.31(a), TWC, §26.121 and TNRCC Permit Number WQ0003274, Special Provision Numbers VI.1.1.2 and VI.2.2.1, by failing to prevent the discharge of waste and/or wastewater from the retention control structure and via irrigation tailwater into or adjacent to waters in the state; §321.39(f)(24)(K), by failing to prevent the ponding of non-point source waste and/or wastewater in the open lot east of the primary and secondary lagoons; §321.39(f)(28) and TNRCC Permit Number WQ0003274, Special Provision Number VI.2.3, by failing to perform the required soil analysis and submit the results; §321.39(f)(29), and TNRCC Permit Number WQ0003274, Special Provision Number VI.2.4, by failing to perform the required irrigation wastewater analysis and submit the results; PENALTY: $9,375; STAFF ATTORNEY: Dwight Martin, Litigation Division, MC 175, (512) 239-0682; REGIONAL OFFICE: Tyler Regional Office, 2916 Teague Drive, Tyler, Texas 75701-3756, (903) 535-5100.

TRD-200105958
Paul C. Sarahan
Director, Litigation Division
Texas Natural Resource Conservation Commission
Filed: October 2, 2001

♦ ♦ ♦

## Notice of Public Hearing

In accordance with the requirements of Texas Government Code, Chapter 2001, Subchapter B, the Texas Natural Resource Conservation Commission (TNRCC or commission) will conduct a public hearing to receive testimony concerning the proposed amended section in 30 TAC Chapter 290, Public Drinking Water.

House Bill 2912, 77th Legislature, 2001 mandates the commission to consider equity in the establishment of the public health drinking water fee rates. The proposed amendment to this chapter is intended to consider equity while generating overall revenue at the current revenue stream. The revenue generated from the new fee assessment does not exceed the amount appropriated by the legislature for fiscal year (FY) 2002, nor is it greater than the revenue generated under the previous assessment in FY 2001.

A public hearing on this proposal will be held November 8, 2001, at 10:00 a.m., Texas Natural Resource Conservation Commission Complex, Building C, Room 131E, 12100 Park 35 Circle (North I-35), Austin. The hearing is structured for the receipt of oral or written comments by interested persons. Individuals may present oral statements when called upon in order of registration. Open discussion will not occur during the hearing; however, agency staff members will be available to discuss the proposal 30 minutes prior to the hearing, and will answer questions before and after the hearing.

Comments may be submitted to Patricia Durón, MC 205, Texas Natural Resource Conservation Commission, Office of Environmental Policy, Analysis, and Assessment, P.O. Box 13087, Austin, Texas 78711-3087, or by fax to (512) 239-4808. All comments should reference Rule Log Number 2001-099-290-AD. Comments must be received by 5:00 p.m., November 12, 2001. For further information contact Debi Dyer at (512) 239-3972.

Persons with disabilities who have special communication or other accommodation needs who are planning to attend the hearing should contact the Office of Environmental Policy, Analysis, and Assessment at (512) 239-4900. Requests should be made as far in advance as possible.

TRD-200105857
Stephanie Bergeron
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Filed: September 27, 2001

♦ ♦ ♦

## Notice of Public Hearing

In accordance with the requirements of Texas Government Code, Chapter 2001, Subchapter B, the Texas Natural Resource Conservation Commission (TNRCC or commission) will conduct a public hearing to receive comments concerning new 30 TAC Chapter 60, Compliance History.

House Bill 2912, 77th Legislature, 2001, §4.01, amended Texas Water Code, Chapter 5, Texas Natural Resource Conservation Commission, by adding Subchapter Q, Performance-Based Regulation, which requires the commission to "develop a uniform standard for evaluating compliance history." New Chapter 60 would define the applicability and components of compliance history.

A public hearing on this proposal will be held in Austin on November 12, 2001 at 10:00 a.m. at the commission's central office, Building F, Room 2210, located at 12100 Park 35 Circle. The hearing will be structured for the receipt of oral or written comments by interested persons. Individuals may present oral statements when called upon in order of registration. There will be no open discussion during the hearing; however, an agency staff member will be available to discuss the proposal 30 minutes prior to the hearing and will answer questions before and after the hearing. Persons with disabilities who have special communication or other accommodation needs who are planning to attend the hearing should contact the Office of Environmental Policy, Analysis, and Assessment at (512) 239-4900. Requests should be made as far in advance as possible.

Written comments may be submitted to Joyce Spencer, MC-205, Texas Natural Resource Conservation Commission, Office of Environmental Policy, Analysis, and Assessment, P.O. Box 13087, Austin, Texas 78711-3087, or by fax to (512) 239-4808. All comments should reference Rule Log Number 2001-070-060-AD. Comments must be received by 5:00 p.m., November 12, 2001. For further information, please contact Debra Barber, Policy and Regulations Division, (512) 239-0412.

TRD-200105943
Stephanie Bergeron
Division Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Filed: October 1, 2001

♦ ♦ ♦

## Notice of Water Quality Applications.

The following notices were issued during the period of September 20, 2001 through September 28, 2001.

The following require the applicants to publish notice in the newspaper. The public comment period, requests for public meetings, or requests for a contested case hearing may be submitted to the Office of the Chief Clerk, Mail Code 105, P O Box 13087, Austin Texas 78711-3087,

WITHIN 30 DAYS OF THE DATE OF NEWSPAPER PUBLICATION OF THIS NOTICE.

AQUASOURCE DEVELOPMENT has applied for a new permit, proposed Texas Pollutant Discharge Elimination System (TPDES) Permit No. 14272-001, to authorize the discharge of treated domestic wastewater at a daily average flow not to exceed 150,000 gallons per day. The facility is located approximately 5,500 feet east- southeast of the intersection of Grant Road and Shaw Road in Harris County, Texas.

AUSTOFIELD PARTNERS NO. 1, LTD. a private, wastewater treatment plant owner, has applied for a new permit, proposed Texas Pollutant Discharge Elimination System (TPDES) Permit No. 14289-001, to authorize the discharge of treated domestic wastewater at a daily average flow not to exceed 375,000 gallons per day. The facility will be located approximately 1.6 miles east of the intersection of Wilson Road and Will Clayton Parkway, and approximately 400 feet north of Will Clayton Parkway in Harris County, Texas.

AZLE INDEPENDENT SCHOOL DISTRICT has applied for a renewal of Permit No. 13304-001, which authorizes the disposal of treated domestic wastewater at a daily average flow not to exceed 9,000 gallons per day via surface irrigation of 4.42 acres of land. The facility and disposal site are located approximately 3.5 miles southwest of the Town of Azle and adjacent to and east of Farm-to-Market Road 730 in Parker County, Texas.

CANYON REGIONAL WATER AUTHORITY has applied for a major amendment to Permit No. 14126-001 to authorizes the land application of water treatment sludge for beneficial use on 40 acres. This permit will not authorize a discharge of pollutants into waters in the State. The facility and disposal site are located on the south bank of the Guadalupe River, approximately 1,000 feet southwest of the dam for Lake Dunlap at Dittmar Falls, and approximately 3,000 feet northeast of the Town of Schumansville in Guadalupe County, Texas. The sludge treatment works and the sludge disposal site are located on the south bank of the Guadalupe River, approximately 1,000 feet southwest of the dam for Lake Dunlap at Dittmar Falls, and approximately 3,000 feet northeast of the Town of Schumansville in Guadalupe County, Texas.

CITY OF THE COLONY has applied to the Texas Natural Resource Conservation Commission (TNRCC) for a renewal of TNRCC Permit No. 11570-001, which authorizes the discharge of treated domestic wastewater at a daily average flow not to exceed 3,390,000 gallons per day. The draft permit authorizes the discharge of treated domestic wastewater at an annual average flow not to exceed 3,390,000 gallons per day. The facility is located approximately 0.2 mile east and 2.7 miles north of the intersection of State Highway 121 and Farm-to-Market Road 423, near Stewart Creek in the City of The Colony in Denton County, Texas.

COUNTY OF HIDALGO has applied for a Texas Pollutant Discharge Elimination System (TPDES) wastewater permit. The applicant has an existing Texas Natural Resource Conservation Commission (TNRCC) Permit No. 10973-001 which authorizes the discharge of treated domestic wastewater at a daily average flow not to exceed 5,000 gallons per day. The plant site is located approximately 2 miles north of the intersection of Farm-to- Market Roads 88 and 1422, east of Farm-to-Market Road 88, adjacent to the Monte Alto Reservoir in Hidalgo County, Texas.

CITY OF HONEY GROVE has applied for a renewal of TPDES Permit No. 10710-003, which authorizes the discharge of treated domestic wastewater at a daily average flow not to exceed 300,000 gallons per day. The facility is located approximately 2,000 feet west from Farm-to-Market Road 100 and approximately 3,000 feet north of U.S. Highway 82 in Fannin County, Texas.

CITY OF MAUD has applied for a new permit, proposed Texas Pollutant Discharge Elimination System (TPDES) Permit No. 14025-001, to authorize the discharge of treated domestic wastewater at a daily average flow not to exceed 192,000 gallons per day. The plant site is located approximately 1,500 feet south of U.S. Highway 67 and St. Louis Southwestern Railroad, and approximately 5,000 feet east of the intersection of U.S. Highway 67 and State Highway 8 in Bowie County, Texas.

NORTH TEXAS MUNICIPAL WATER DISTRICT has applied for renewal of an existing wastewater permit. The applicant has an existing National Pollutant Discharge Elimination System (NPDES) Permit No. TX0078565 and an existing Texas Natural Resource Conservation Commission (TNRCC) Permit No. 12047-001. The draft permit authorizes the discharge of treated domestic wastewater at an annual average flow not to exceed 2,250,000 gallons per day. The plant site is located on the west side of Buffalo Creek and on the south side of Farm-to-Market Road 3097 approximately 1.5 miles northwest of the intersection of Farm-to-Market Roads 3097 and 549 in the City of Rockwall in Rockwall County, Texas.

CITY OF PORT NECHES has applied to the Texas Natural Resource Conservation Commission (TNRCC) for a renewal of TNRCC Permit No. 10477-004, which authorizes the discharge of treated domestic wastewater at an annual average flow not to exceed 4,980,000 gallons per day. The facility is located in the 6400 block of Georgia Street, approximately 1 mile northwest of the intersection of State Highway 347 and State Highway 73 in Jefferson County, Texas.

CITY OF UVALDE has applied for a renewal of TPDES Permit No. 10306-001, which authorizes the discharge of treated domestic wastewater at an annual average flow not to exceed 2,500,000 gallons per day. The current permit authorizes the land application of sewage sludge for beneficial use on 55 acres. The sludge disposal site is located on a crop land totaling approximately 55 acres adjacent to the plant site along the road entering the plant. The facility is located approximately 1.3 miles southwest of the intersection of Farm-to-Market Road 117 and U.S. Highway 83 in Uvalde County, Texas.

TRD-200105969
LaDonna Castañuela
Chief Clerk
Texas Natural Resource Conservation Commission
Filed: October 2, 2001

♦ ♦ ♦

## Proposal for Decision

The State Office Administrative Hearing issued a Proposal for Decision and Order to the Texas Natural Resource Conservation Commission on September 28, 2001 Executive Director of the Texas Natural Resource Conservation Commission, Petitioner v. Final Oil & Chemical Company; Respondent; SOAH Docket No.582-95-1044; TNRCC Docket No.95-1004-ISW-E. In the matter to be considered by the Texas Natural Resource Conservation Commission on a date and time to be determined by the Chief Clerk's Office in Room 201S of Building E, 12118 N. Interstate 35, Austin, Texas. This posting is Notice of Opportunity to Comment on the Proposal for Decision and Order. The comment period will end 30 days from date of publication. Written public comments should be submitted to the Office of the Chief Clerk, MC-105, TNRCC, PO Box 13087, Austin, Texas 78711-3087. If you have any questions or need assistance, please contact Doug Kitts, Chief Clerk's Office, (512) 239-3317.

TRD-200105968

Douglas A. Kitts
Agenda Coordinator
Texas Natural Resource Conservation Commission
Filed: October 2, 2001

♦ ♦ ♦

## Texas Parks and Wildlife Department

### Correction of Error

The Texas Parks and Wildlife Department adopted 31 TAC §53.90, concerning Exemptions from Stamp Fees in the August 31, 2001, issue of the *Texas Register* (26 TexReg 6714). Due to a typographical error the rule was published as §53.190. The correct section number is §53.90.

TRD-200105884

♦ ♦ ♦

## Public Utility Commission of Texas

### Notice of Application for a Certificate to Provide Retail Electric Service

Notice is given to the public of the filing with the Public Utility Commission of Texas (commission) of an application on September 27, 2001, for retail electric provider (REP) certification, pursuant to §§39.101 - 39.109 of the Public Utility Regulatory Act (PURA). A summary of the application follows.

Docket Title and Number: Application of Texas Commercial Energy, L.L.C. for Retail Electric Provider (REP) certification, Docket Number 24752 before the Public Utility Commission of Texas.

Applicant's requested service area by geography includes the entire State of Texas.

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 no later than October 19, 2001. Hearing and speech-impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136.

TRD-200105951
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: October 2, 2001

♦ ♦ ♦

### Notice of Application for Amendment to Service Provider Certificate of Operating Authority

On September 27, 2001, R Tex Communications Group, Inc. filed an application with the Public Utility Commission of Texas (commission) to amend its service provider certificate of operating authority (SPCOA) granted in SPCOA Certificate Number 60392. Applicant intends to (1) remove the resale-only restriction; and (2) expand its geographic area to include the entire State of Texas.

The Application: Application of R Tex Communications Group, Inc. for an Amendment to its Service Provider Certificate of Operating Authority, Docket Number 24751.

Persons with questions about this docket, or who wish to intervene or otherwise participate in these proceedings should make appropriate filings or comments to the Public Utility Commission of Texas, P.O. Box 13326, Austin, Texas 78711-3326 no later than October 17, 2001. You may contact the commission's Customer Protection Division at (512) 936-7120. Hearing and speech- impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 24751.

TRD-200105950
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: October 2, 2001

♦ ♦ ♦

### Notice of Application for Relinquishment of a Service Provider Certificate of Operating Authority

On September 24, 2001, Edge Connections, Inc. filed an application with the Public Utility Commission of Texas (commission) to relinquish its service provider certificate of operating authority (SPCOA) granted in SPCOA Certificate Number 60390. Applicant intends to relinquish its certificate.

The Application: Application of Edge Connections, Inc. to Relinquish its Service Provider Certificate of Operating Authority, Docket Number 24625.

Persons with questions about this docket, or who wish to intervene or otherwise participate in these proceedings should make appropriate filings or comments to the Public Utility Commission of Texas, P.O. Box 13326, Austin, Texas 78711-3326 no later than October 17, 2001. You may contact the commission's Customer Protection Division at (512) 936-7120. Hearing and speech- impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 24625.

TRD-200105848
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: September 26, 2001

♦ ♦ ♦

### Notice of Application for Waiver from an Energy Efficiency Template

Notice is given to the public of the filing with the Public Utility Commission of Texas (commission) of an application on September 27, 2001, for waiver to permit a modification to the "program template" for an energy efficiency program approved by the commission in Project Number 22241.

Docket Title and Number: Application of Entergy-Gulf States Texas (EGSI) for Waiver From an Energy Efficiency Template. Docket Number 24746.

The Application: EGSI stated that it is requesting a waiver to add this additional feature to ensure that a more-comprehensive set of measures are implemented to better meet the energy efficiency needs of the "Hard-To-Reach" (HTR) customer segment. Furthermore, EGSI opined that this waiver is requested on a one-year "pilot" basis and involves a relatively small portion of EGSI's total program budget for energy efficiency activities. EGSI believes that it would be in the public interest to permit it to augment the existing Residential and Small Commercial Standard Offer Program to require an Energy Efficiency Service Provider that wishes to serve HTR customers to implement at least one of the following "first priority" measures (e.g., ceiling insulation, wall insulation, or air infiltration reduction) as identified in the program template for the HTR Standard Offer Program at each customer site.

Persons who wish to comment upon the action sought should contact the Public Utility Commission of Texas, by mail at P.O. Box 13326, Austin, Texas, 78711-3326, or call the commission's Customer Protection Division at (512) 936-7120 or toll free at 1-888-782-8477. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All comments should reference Docket Number 24746.

TRD-200105967
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: October 2, 2001

♦ ♦ ♦

## Notice of Application to Relinquish a Service Provider Certificate of Operating Authority

On September 26, 2001, Ameritech Communications International, Inc. filed an application with the Public Utility Commission of Texas (commission) to relinquish its service provider certificate of operating authority (SPCOA) granted in SPCOA Certificate Number 60092. Applicant intends to relinquish its certificate.

The Application: Application of Ameritech Communications International, Inc. to Relinquish its Service Provider Certificate of Operating Authority, Docket Number 24741.

Persons with questions about this docket, or who wish to intervene or otherwise participate in these proceedings should make appropriate filings or comments to the Public Utility Commission of Texas, P.O. Box 13326, Austin, Texas 78711-3326 no later than October 17, 2001. You may contact the commission's Customer Protection Division at (512) 936-7120. Hearing and speech- impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 24741.

TRD-200105915
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: October 1, 2001

♦ ♦ ♦

## Notice of Petition for Expanded Local Calling Service

Notice is given to the public of the filing with the Public Utility Commission of Texas (commission) of a petition on August 24, 2001, for expanded local calling service (ELCS) pursuant to Chapter 55, Subchapter C of the Public Utility Regulatory Act (PURA). A summary of the application follows.

Project Title and Number: Petition of the Rosewood Exchange for Expanded Local Calling Service, Project Number 24554.

The petitioners in the Rosewood Exchange request ELCS to the exchanges of Big Sandy and Winnsboro.

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 no later than October 29, 2001. Hearing and speech-impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136.

TRD-200105914
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: October 1, 2001

♦ ♦ ♦

## Public Notice of Interconnection Agreement

On September 25, 2001, United Telephone Company of Texas, Inc., doing business as Sprint, Central Telephone Company of Texas doing business as Sprint (collectively, Sprint), and United Technological Systems, Inc. doing business as Uni-Tel, collectively referred to as applicants, filed a joint application for approval of interconnection agreement under Section 252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998 & Supplement 2001) (PURA). The joint application has been designated Docket Number 24737. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 24737. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by October 26, 2001, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the commission's Customer Protection Division at (512) 936-7120 or toll free at 1-888-782-8477. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 24737.

TRD-200105849
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: September 26, 2001

♦ ♦ ♦

## Public Notice of Workshop on Capacity Auctions

The Public Utility Commission of Texas (commission) will hold a workshop regarding possible changes to the capacity auction mechanics and commission procedures for the capacity auctions scheduled to be held in March 2002 and July 2002, on Friday, October 19, 2001, at 9:30 a.m. in Hearing Room Gee located on the 7th floor of the William B. Travis Building, 1701 North Congress Avenue, Austin, Texas 78701. Project Number 24492, *Rulemaking Proceeding to Revise Substantive Rule §25.381, Capacity Auctions*, has been established for this proceeding.

Questions concerning the workshop or this notice should be referred to Eric Schubert, Senior Market Economist, Market Oversight Division, 512-936-7398. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136.

TRD-200105864
Rhonda G. Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: September 27, 2001

♦ ♦ ♦

## Public Notice of Workshop Rulemaking to Amend USF Rules Regarding UNE Sharing Mechanism

The staff of the Public Utility Commission of Texas (commission) will hold a workshop regarding alternative methods to increase competition within rural areas via amendments to the universal service fund (USF) rules regarding the unbundled network element (UNE) sharing mechanism on Tuesday, October 30, 2001, at 9:30 a.m. in the Commissioners' Hearing Room, located on the 7th floor of the William B. Travis Building, 1701 North Congress Avenue, Austin, Texas 78701. Project Number 24526, *Rulemaking to Amend USF Rules Regarding Unbundled Network Element Sharing Mechanism*, is assigned to this proceeding. Interested parties may sign onto the list server located on the project's webpage located at http://www.puc.state.tx.us/rules/rulemake/24526/24526.cfm

Staff's proposed questions will be posted on this webpage prior to the workshop.

Questions concerning the workshop or this notice should be referred to Lori Cobos, Policy Analyst, Policy Development Division, at (512) 936-7242. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136.

TRD-200105912
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: October 1, 2001

♦ ♦ ♦

## Request for Proposals to Assist in Implementing a Statewide "Do Not Call" List

The Public Utility Commission of Texas (commission) is issuing a Request for Proposals (RFP) for a vendor or vendors who will assist the commission in implementing and maintaining a statewide do not call program. The commission is authorized to enter into a contract for the operation of the database. This RFP is issued pursuant to the commission's authority under Title IV, Texas Business and Commerce Code, Chapter 43, Subchapter C, §§43.101 though 43.104 and Title II, Texas Utilities Code, Public Utility Regulatory Act, Chapter 39, Subchapter C, §39.1025. The commission is responsible for establishing and operating a database that lists the names, addresses, and telephone numbers of consumers in this state who object to receiving unsolicited telemarketing or telephone calls. In addition to this general list, the commission must also establish and operate a database for electric consumers who object to receiving unsolicited telemarketing or telephone calls relating to the customer's choice of retail electric providers.

To be considered, an original and six copies (seven total) of the proposal must arrive at the commission on or before 3:00 p.m. Central Standard Time (CST), Thursday, November 8, 2001.

Eligible Proposers. The commission is requesting proposals from entities with more than two years relevant experience in administering comparable databases. Entities that meet the definition of a historically underutilized business (HUB) as defined in Texas Government Code, Chapter 2161, §2161.001, are encouraged to submit a proposal.

Project Description. This RFP contains three different services for which a vendor will be needed. These services include, but are not limited to, the following: (1) acceptance of applications and fees; (2) data entry and maintenance of database(s) to compile registrant information; and, (3) access to the do not call list by appropriate parties upon proper request. Bidders must submit proposals to perform each of the services described. Bidders planning to combine with other vendors in a common effort should provide all the requested information for all vendors involved.

Selection Criteria. The vendor(s) will be selected based on the ability of the proposer to provide the best value in carrying out requirements identified in the RFP. Evaluation criteria will include, but is not limited to, evidence of ability to manage the project; experience of the organization; qualifications of assigned personnel; evidence of successful projects of similar nature; the clarity of the description of details for carrying out the project; the total estimated fees; and whether the proposed project time lines are logical and appropriate. A complete description of selection criteria is set forth in the RFP. Proposers will be notified in writing of the selection.

Requesting the Proposal. A complete copy of the RFP may be obtained by writing Patricia Dolese, Public Utility Commission of Texas, P.O. Box 13326, Austin, Texas 78711-3326, or email Patricia.Dolese@puc.state.tx.us, or faxing (512) 936-7003. The RFP will be available Friday, October 12, 2001. The RFP will also be available at the commission's website (www.puc.state.tx.us) under Project Number 24376.

Deadline for Receipt of Proposals. Proposals must be received no later than 3:00 p.m. CST on Thursday, November 8, 2001 in the Central Records Division of the Public Utility Commission of Texas, Room G-113, William B. Travis Building, 1701 North Congress Avenue, P.O. Box 13326, Austin, Texas 78711-3326. Proposals received in Central Records after 3:00 p.m., Thursday, November 8, 2001, will not be considered. Proposals may be filed in Central Records between 9:00 a.m. and 5:00 p.m. Monday through Friday. Regardless of the method of submission of the proposal, the commission will rely solely on Central

Records' time/date stamp in establishing the time and date of receipt. Proposals should be filed under Project Number 24376.

TRD-200105966
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: October 2, 2001

♦ ♦ ♦

## Texas A&M University System, Board of Regents

### Public Notice

Pursuant to Section 552.123, Texas Government Code, the following candidate is the finalist for the position of President of The Texas A&M University System Health Science Center and upon the expiration of twenty-one days, final action is to be taken by the Board of Regents of The Texas A&M University System:

(1) Dr. Nancy Wilson Dickey

TRD-200105886
Vickie Burt Spillers
Executive Secretary to the Board
Texas A&M University System, Board of Regents
Filed: September 28, 2001

♦ ♦ ♦

## Texas Department of Transportation

### Public Hearing Notice - Highway Project Selection Process

In accordance with Transportation Code, §201.602, the Texas Transportation Commission (commission) will conduct a public hearing to receive data, comments, views, and/or testimony concerning the commission's highway project selection process and the relative importance of the various criteria on which the commission bases its project selection decisions. It is emphasized that the subject of the hearing will be the procedure by which projects are selected and not the merits or details of specific projects themselves.

The public hearing will be held on Thursday, November 15, 2001, at 9:00 a.m., in the first floor hearing room of the Dewitt C. Greer State Highway Building, 125 E. 11th Street, Austin, Texas. The hearing will be held in accordance with the procedures specified in 43 TAC §1.5. Any interested person may appear and offer comments, either orally or in writing; however, questioning of those making presentations will be reserved exclusively to the commission as may be necessary to ensure a complete record. While any person with pertinent comments or testimony concerning the selection procedure will be granted an opportunity to present them during the course of the hearing, the commission reserves the right to restrict testimony in terms of time and repetitive comment. Organizations, associations, or groups are encouraged to present their commonly-held views, and same or similar comments, through a representative member where possible. Presentations must remain pertinent to the issue being discussed. A person may not assign a portion of his or her time to another speaker. Persons with disabilities who plan to attend the hearing and who may need auxiliary aids or services such as interpreters for persons who are deaf or hearing impaired, readers, large print or Braille, are requested to contact Randall Dillard, Director, Public Information Office, at 125 E. 11th St., Austin, Texas 78701-2383, or (512) 305-9196 at least two working days prior to the hearing so that appropriate arrangements can be made.

Copies of the criteria/information will be available beginning October 15, 2001, at the department's Riverside Annex, 118 E. Riverside Drive, Bldg. 118, Room 2B-6, Austin, (512) 486-5050. Written comments may be submitted to the Texas Department of Transportation, Attention: James L. Randall, P.E., P.O. Box 149217, Austin, Texas 78714-9217. The deadline for receipt of comments is 5:00 p.m. on January 29, 2002.

TRD-200105980
Bob Jackson
Associate General Counsel
Texas Department of Transportation
Filed: October 3, 2001

♦ ♦ ♦

### Public Hearing Notice - Oversize and Overweight Vehicles and Loads

In accordance with the requirements of the Administrative Procedure Act, Government Code, Chapter 2001, Subchapter B, the Texas Department of Transportation will conduct a public hearing to receive comments on the proposed amendments to §§28.11, 28.13 and 28.14, concerning general permits for oversize and overweight vehicles and loads. The amendments were published in the September 14, 2001, issue of the Texas Register (26 TexReg 7100). A public hearing will be held at 9:00 a.m. on October 23, 2001, in the first floor hearing room of the Dewitt C. Greer State Highway Building, 125 E. 11th Street, Austin, Texas, and will be conducted in accordance with the procedures specified in 43 TAC §1.5. Those desiring to make comments or presentations may register starting at 8:30 a.m.

House Bill 468, 77th Legislature, 2001 amended Transportation Code, §623.093. The amendments to §623.093 require that applications for a permit to move a manufactured home (other than a move from the retailer pursuant to an original sale) be accompanied by documentation showing the home's ad valorem tax status.

The amendments are necessary to implement this legislation and to clarify policies and procedures concerning issuance of oversize/overweight permits, thereby preserving the transportation infrastructure, and providing safe, effective and efficient movement of people and goods. The amendments further ensure the department's proper administration of the laws concerning the issuance of permits for the movement of oversize and overweight loads.

Any interested person may appear and offer comments, either orally or in writing; however, questioning of those making presentations will be reserved exclusively to the presiding officer as may be necessary to ensure a complete record. While any person with pertinent comments will be granted an opportunity to present them during the course of the hearing, the presiding officer reserves the right to restrict testimony in terms of time and repetitive content. Organizations, associations, or groups are encouraged to present their commonly held views, and same or similar comments, through a representative member where possible. Presentations must remain pertinent to the issue being discussed. A person may not assign a portion of his or her time to another speaker. Persons with disabilities who have special communication or accommodation needs and who plan to attend the hearing and who may need auxiliary aids or services such as interpreters for persons who are deaf or hearing impaired, readers, large print or Braille, are requested to contact Randall Dillard, Director of the Public Information Office, at 125 E. 11th St., Austin, Texas 78701-2483, (512) 463-8588, at least two weeks prior to the hearing so that appropriate arrangements can be made.

Written comments on the proposed amendments may be submitted to Lawrance R. Smith, Director, Motor Carrier Division, 125 East 11th

Street, Austin, Texas 78701-2483. The deadline for receipt of comments is extended from October 15, 2001, to 5:00 p.m. on October 30, 2001.

TRD-200105981
Bob Jackson
Associate General Counsel
Texas Department of Transportation
Filed: October 3, 2001

♦ ♦ ♦

## The University of Texas System

### Notice of Entering Into A Major Consulting Services Contract

The University of Texas System has entered into a contract for consulting services. The consultant will assist the University with identifying issues related to implementation and evaluation of long-range planning.

The name and address of the consultant are as follows:

TVM Consulting

815A Brazos Street, Suite 505

Austin, Texas 78751

The University will pay a fixed fee of $57,000. The contract will run from September 19, 2001 until December 31, 2002. Any reports required will be due no later than December 31, 2002.

Any questions regarding this posting should be directed to:

Mr. Arthur Martinez

Associate Director

Office of Business and Administrative Services

The University of Texas System

201 West 7th Street

Austin, Texas 78701

Voice: 512/499-4584

Email: Amartinez@utsystem.edu

TRD-200105896
Francie Frederick
Counsel and Secretary to the Board of Regents
The University of Texas System
Filed: October 1, 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:

City of Mexia, 101 South McKinney Street, P.O. Box 207, Mexia, Texas, 76667, received August 31, 2001, application for financial assistance in the amount of $5,420,000 from the Clean Water State Revolving Fund.

City of Olney, 201 E. Main, P.O. Box 546, Olney, Texas, 76374-0546, received August 21, 2001, application for financial assistance in the amount of $265,000 from the Clean Water State Revolving Fund.

City of Kaufman, 209 South Washington, Kaufman, Texas, 75142, received August 31, 2001, application for financial assistance in the amount of $2,455,000 from the Clean Water State Revolving Fund.

City of Ingleside, 5024 Broadway, Ingleside, Texas, 76117, received February 28, 2001, application for financial assistance in the total amount of $4,597,390 from the Economically Distressed Areas Account of the Texas Water Development Fund.

City of Odem, 14916 Main, Odem, Texas, 78052, received June 20, 2001, application for financial assistance in the amount of $2,618,616 from the Economically Distressed Areas Account of the Texas Water Development Fund.

City of Willis, 200 North Bell, Willis, Texas, 77378, received August 31, 2001, application for financial assistance in the amount of $1,000,000 from the Clean Water State Revolving Fund.

City of Houston, P.O. Box 1562, Houston, Texas, 77251-1562, received August 28, 2001, application for financial assistance in the amount of $50,050,000 from the Clean Water State Revolving Fund.

Panhandle Regional Planning Commission, P. O. Box 9257, Amarillo, Texas, 79105, received September 21, 2001, application for financial assistance in an amount not to exceed $17,200 from the Research and Planning Fund.

Red River Authority of Texas, 900 8th Street, Suite 520, Wichita Falls, Texas, 76301-6894, received September 20, 2001, application for financial assistance in an amount not to exceed $15,000 from the Research and Planning Fund.

North Texas Municipal Water Authority, P. O. Drawer C, Wylie, Texas, 75098, received September 21, 2001, application for financial assistance in an amount not to exceed $80,000 from the Research and Planning Fund.

Northeast Texas Municipal Water District, P. O. Box 9555, Hwy. 250 South, Hughes Springs, Texas, 75656, received September 18, 2001, application for financial assistance in an amount not to exceed $28,900 from the Research and Planning Fund.

Rio Grande Council of Governments, 1100 N. Stanton, Suite 610, El Paso, Texas, 79902, received September 7, 2001, application for financial assistance in an amount not to exceed $15,000 from the Research and Planning Fund.

Colorado River Municipal Water District, P. O. Box 869, Big Spring, Texas, 79721-0869, received September 21, 2001, application for financial assistance in an amount not to exceed $20,800 from the Research and Planning Fund.

Brazos River Authority, P.O. Box 7555, Waco, Texas, 76714-7555, received September 21, 2001, application for financial assistance in an amount not to exceed $154,350 from the Research and Planning Fund.

San Jacinto River Authority, P. O. Box 329, Conroe, Texas, 77305-0329, received September 21, 2001, application for financial assistance in an amount not to exceed $48,200 from the Research and Planning Fund.

Deep East Texas Council of Governments, 274 East Lamar, Jasper, Texas, 75951, received September 20, 2001, application for financial assistance in an amount not to exceed $41,200 from the Research and Planning Fund.

Upper Guadalupe River Authority, 125 Lehmann Drive, Suite 100, Kerrville, Texas, 78028, received September 20, 2001, application for financial assistance in an amount not to exceed $13,000 from the Research and Planning Fund.

Lower Colorado River Authority, P. O. Box 220, Austin, Texas 78767, received September 20, 2001, application for financial assistance in an amount not to exceed $15,000 from the Research and Planning Fund.

San Antonio River Authority, P. O. Box 839980, San Antonio, Texas, 78283, received September 20, 2001, application for financial assistance in an amount not to exceed $28,800.32 from the Research and Planning Fund.

Lower Rio Grande Valley Development Council, 311 North 15th Street, McAllen, Texas, 78501, received September 7, 2001, application for financial assistance in an amount not to exceed $19,200 from the Research and Planning Fund.

Nueces River Authority, 6300 Ocean Drive, NRC 3100, Corpus Christi, Texas, 78412, received September 21, 2001, application for financial assistance in an amount not to exceed $15,000 from the Research and Planning Fund.

High Plains Underground Water Conservation District No. 1, 2930 Avenue Q, Lubbock, Texas, 79405-1499, received September 18, 2001, application for financial assistance in an amount not to exceed $15,000 from the Research and Planning Fund.

Lavaca-Navidad River Authority, P.O. Box 429, Edna, Texas, 77957-0429, received September 21, 2001, application for financial assistance in an amount not to exceed $15,000 from the Research and Planning Fund.

TRD-200105987
Gail L. Allan
Director of Project-Related Legal Services
Texas Water Development Board
Filed: October 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).

**<u>Texas Natural Resource Conservation Commission, Title 30</u>**

❑ **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

**<u>Texas Workers Compensation Commission, Title 28</u>**

❑ Update service $25/year

| | |
|---|---|
| **<u>Texas Register Phone Numbers</u>** | **(800) 226-7199** |
| Documents | (512) 463-5561 |
| Circulation | (512) 463-5575 |
| Marketing | (512) 305-9623 |
| Texas Administrative Code | (512) 463-5565 |

**<u>Information For Other Divisions of the Secretary of State’s Office</u>**

| | |
|---|---|
| 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