TITLE 16. ECONOMIC REGULATION
PART 1. RAILROAD COMMISSION OF TEXAS
CHAPTER 8. PIPELINE SAFETY REGULATIONS
SUBCHAPTER A. GENERAL REQUIREMENTS AND DEFINITIONS

§8.1. General Applicability and Standards.

(a) Applicability.

(1) The rules in this chapter establish minimum standards of accepted good practice and apply to:

(A) all gas pipeline facilities and facilities used in the intrastate transportation of gas, including LPG distribution systems and master metered systems, as provided in 49 United States Code (U.S.C.) §§60101, *et seq*.; and Texas Utilities Code, §§121.001 - 121.507;

(B) onshore pipeline and gathering and production facilities, beginning after the first point of measurement and ending as defined by 49 CFR Part 192 as the beginning of an onshore gathering line. The gathering and production beyond this first point of measurement shall be subject to 49 CFR Part 192.8 and shall be subject to the rules as defined as Type A or Type B gathering lines as those Class 2, 3, or 4 areas as defined by 49 CFR Part 192.5;

(C) the intrastate pipeline transportation of hazardous liquids or carbon dioxide and all intrastate pipeline facilities as provided in 49 U.S.C. §§60101, *et seq*.; and Texas Natural Resources Code, §117.011 and §117.012; and

(D) all pipeline facilities originating in Texas waters (three marine leagues and all bay areas). These pipeline facilities include those production and flow lines originating at the well.

(2) The regulations do not apply to those facilities and transportation services subject to federal jurisdiction under: 15 U.S.C. §§717, *et seq*.; or 49 U.S.C. §§60101, *et seq*.

(b) Minimum safety standards. The Commission adopts by reference the following provisions, as modified in this chapter, effective October 1, 2011.

(1) Natural gas pipelines, including LPG distribution systems and master metered systems, shall be designed, constructed, maintained, and operated in accordance with 49 U.S.C. §§60101, *et seq*.; 49 Code of Federal Regulations (CFR) Part 191, Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports; 49 CFR Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards; and 49 CFR Part 193, Liquefied Natural Gas Facilities: Federal Safety Standards.

(2) Hazardous liquids or carbon dioxide pipelines shall comply with 49 U.S.C. §§60101, *et seq*.; and 49 CFR Part 195, Transportation of Hazardous Liquids by Pipeline.

(3) All operators of pipelines and/or pipeline facilities shall comply with 49 CFR Part 199, Drug and Alcohol Testing, and 49 CFR Part 40, Procedures for Transportation Workplace Drug and Alcohol Testing Programs.

(4) All operators of pipelines and/or pipeline facilities, other than master metered systems and distribution systems, shall comply with §3.70 of this title (relating to Pipeline Permits Required).

(c) Special situations. Nothing in this chapter shall prevent the Commission, after notice and hearing, from prescribing more stringent standards in particular situations. In special circumstances, the Commission may require the following:

(1) Any operator which cannot determine to its satisfaction the standards applicable to special circumstances may request in writing the Commission's advice and recommendations. In a special case, and for good cause shown, the Commission may authorize exemption, modification, or temporary suspension of any of the provisions of this chapter, pursuant to the provisions of §8.125 of this title (relating to Waiver Procedure).

(2) If an operator transports gas and/or operates pipeline facilities which are in part subject to the jurisdiction of the Commission and in part subject to the Department of Transportation pursuant to 49 U.S.C. §§60101, *et seq*. the operator may request in writing to the Commission that all of its pipeline facilities and transportation be subject to the exclusive jurisdiction of the Department of Transportation. If the operator files a written statement under oath that it will fully comply with the federal safety rules and regulations, the Commission may grant an exemption from compliance with this chapter.

(d) Concurrent filing. A person filing any document or information with the Department of Transportation pursuant to the requirements of 49 CFR Parts 190, 191, 192, 193, 195, or 199 shall file a copy of that document or information with the Pipeline Safety Division.

(e) Penalties. A person who submits incorrect or false information with the intent of misleading the Commission regarding any material aspect of an application or other information required to be filed at the Commission may be penalized as set out in Texas Natural Resources Code, §§117.051 - 117.054, and/or Texas Utilities Code, §§121.206 - 121.210, and the Commission may dismiss with prejudice to refiling an application containing incorrect or false information or reject any other filing containing incorrect or false information.

(f) Retroactivity. Nothing in this chapter shall be applied retroactively to any existing intrastate pipeline facilities concerning design, fabrication, installation, or established operating pressure, except as required by the Office of Pipeline Safety, Department of Transportation. All intrastate pipeline facilities shall be subject to the other safety requirements of this chapter.

(g) Compliance deadlines. Operators shall comply with the applicable requirements of this section according to the following guidelines.

(1) Each operator of a pipeline and/or pipeline facility that is new, replaced, relocated, or otherwise changed shall comply with the applicable requirements of this section at the time the pipeline and/or pipeline facility goes into service.

(2) An operator whose pipeline and/or pipeline facility was not previously regulated but has become subject to regulation pursuant to the changed definition in 49 CFR Part 192 and subsection (a)(1)(B) of this section shall comply with the applicable requirements of this section no later than the stated date:

(A) for cathodic protection (49 CFR Part 192), March 1, 2012;

(B) for damage prevention (49 CFR 192.614), September 1, 2010;

(C) to establish an MAOP (49 CFR 192.619), March 1, 2010;

(D) for line markers (49 CFR 192.707), March 1, 2011;

(E) for public education and liaison (49 CFR 192.616), March 1, 2011; and

(F) for other provisions applicable to Type A gathering lines (49 CFR 192.8(c)), March 1, 2011.

The provisions of this §8.1 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective May 15, 2005, 30 TexReg 2849; amended to be effective January 30, 2006, 31 TexReg 480; amended to be effective March 2, 2009, 34 TexReg 1414; amended to be effective August 30, 2010, 35 TexReg 7743; amended to be effective August 6, 2012, 37 TexReg 5738.

§8.5. Definitions. In addition to the definitions given in 49 CFR Parts 40, 191, 192, 193, 195, and 199, the following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--This definition of this term applies only to the procedures and requirements of §8.125 of this title (relating to Waiver Procedure). The term includes but is not limited to:

(A) persons owning or occupying real property within 500 feet of any property line of the site for the facility or operation for which the waiver is sought;

(B) the city council, as represented by the city attorney, the city secretary, the city manager, or the mayor, if the property that is the site of the facility or operation for which the waiver is sought is located wholly or partly within any incorporated municipal boundaries, including the extraterritorial jurisdiction of any incorporated municipality. If the site of the facility or operation for which the waiver is sought is located within more than one incorporated municipality, then the city council of every incorporated municipality within which the site is located is an affected person;

(C) the county commission, as represented by the county clerk, if the property that is the site of the facility or operation for which the waiver is sought is located wholly or partly outside the boundary of any incorporated municipality. If the site of the facility or operation for which the waiver is sought is located within more than one county, then the county commission of every county within which the site is located is an affected person;

(D) any other person who would be impacted by the waiver sought.

(2) Applicant--A person who has filed with the Pipeline Safety Division a complete application for a waiver to a pipeline safety rule or regulation, or a request to use direct assessment or other technology or assessment methodology not specifically listed in §8.101(b)(1), of this title (relating to Pipeline Integrity Assessment and Management Plans for Natural Gas and Hazardous Liquids Pipelines).

(3) Application for waiver--The written request, including all reasons and all appropriate documentation, for the waiver of a particular rule or regulation with respect to a specific facility or operation.

(4) Charter school--An elementary or secondary school operated by an entity created pursuant to Texas Education Code, Chapter 12.

(5) Commission--The Railroad Commission of Texas.

(6) Direct assessment--A structured process that identifies locations where a pipeline may be physically examined to provide assessment of pipeline integrity. The process includes collection, analysis, assessment, and integration of data, including but not limited to the items listed in §8.101(b)(1) of this title, relating to Pipeline Integrity Assessment and Management Plans for Natural Gas and Hazardous Liquids Pipelines. The physical examination may include coating examination and other applicable non-destructive evaluation.

(7) Director--The director of the Pipeline Safety Division or the director's delegate.

(8) Division--The Pipeline Safety Division of the Commission.

(9) Farm tap odorizer--A wick-type odorizer serving a consumer or consumers off any pipeline other than that classified as distribution as defined in 49 CFR 192.3 which uses not more than 10 mcf on an average day in any month.

(10) Gas--Natural gas, flammable gas, or other gas which is toxic or corrosive.

(11) Gas company--Any person who owns or operates pipeline facilities used for the transportation or distribution of gas, including master metered systems.

(12) Hazardous liquid--Petroleum, petroleum products, anhydrous ammonia, or any substance or material which is in liquid state, excluding liquefied natural gas (LNG), when transported by pipeline facilities and which has been determined by the United States Secretary of Transportation to pose an unreasonable risk to life or property when transported by pipeline facilities.

(13) In-line inspection--An internal inspection by a tool capable of detecting anomalies in pipeline walls such as corrosion, metal loss, or deformation.

(14) Intrastate pipeline facilities--Pipeline facilities located within the State of Texas which are not used for the transportation of natural gas or hazardous liquids or carbon dioxide in interstate or foreign commerce.

(15) Lease user--A consumer who receives free gas in a contractual agreement with a pipeline operator or producer.

(16) Liquids company--Any person who owns or operates a pipeline or pipelines and/or pipeline facilities used for the transportation or distribution of any hazardous liquid, or carbon dioxide, or anhydrous ammonia.

(17) Master meter operator--The owner, operator, or manager of a master metered system.

(18) Master metered system--A pipeline system (other than one designated as a local distribution system) for distributing natural gas within but not limited to a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means such as rents.

(19) Natural gas supplier--The entity selling and delivering the natural gas to a school facility or a master metered system. If more than one entity sells and delivers natural gas to a school facility or master metered system, each entity is a natural gas supplier for purposes of this chapter.

(20) Operator--A person who operates on his or her own behalf, or as an agent designated by the owner, intrastate pipeline facilities.

(21) Person--Any individual, firm, joint venture, partnership, corporation, association, cooperative association, joint stock association, trust, or any other business entity, including any trustee, receiver, assignee, or personal representative thereof, a state agency or institution, a county, a municipality, or school district or any other governmental subdivision of this state.

(22) Person responsible for a school facility--In the case of a public school, the superintendent of the school district as defined in Texas Education Code, §11.201, or the superintendent's designee previously specified in writing to the natural gas supplier. In the case of charter and private schools, the principal of the school or the principal's designee previously specified in writing to the natural gas supplier.

(23) Pipeline facilities--New and existing pipe, right-of-way, and any equipment, facility, or building used or intended for use in the transportation of gas or hazardous liquid or their treatment during the course of transportation.

(24) Pressure test--Those techniques and methodologies prescribed for leak-test and strength-test requirements for pipelines. For natural gas pipelines, including LPG distribution systems and master metered systems, the requirements are found in 49 Code of Federal Regulations (CFR) Part 192, and specifically include 49 CFR 192.505, 192.507, 192.515, and 192.517. For hazardous liquids pipelines, the requirements are found in 49 CFR Part 195, and specifically include 49 CFR 195.305, 195.306, 195.308, and 195.310.

(25) Private school--An elementary or secondary school operated by an entity accredited by the Texas Private School Accreditation Commission.

(26) Public school--An elementary or secondary school operated by an entity created in accordance with the laws of the State of Texas and accredited by the Texas Education Agency pursuant to Texas Education Code, Chapter 39, Subchapter D. The term does not include programs and facilities under the jurisdiction of the Texas Department of Mental Health and Mental Retardation, the Texas Youth Commission, the Texas Department of Human Services, the Texas Department of Criminal Justice or any probation agency, the Texas School for the Blind and Visually Impaired, the Texas School for the Deaf and Regional Day Schools for the Deaf, the Texas Academy of Mathematics & Science, the Texas Academy of Leadership in the Humanities, and home schools or proprietary schools as defined in Texas Education Code, §132.001.

(27) School facility--All piping, buildings and structures operated by a public, charter, or private school that are downstream of a meter measuring natural gas service in which students receive instruction or participate in school sponsored extracurricular activities, excluding maintenance or bus facilities, administrative offices, and similar facilities not regularly utilized by students.

(28) Transportation of gas--The gathering, transmission, or distribution of gas by pipeline or its

storage within the State of Texas. For purposes of safety regulation, the term shall include onshore pipeline and production facilities, beginning after the first point of measurement and ending as defined by 49 CFR Part 192 as the beginning of an onshore gathering line.

(29) Transportation of hazardous liquids or carbon dioxide--The movement of hazardous liquids or carbon dioxide by pipeline, or their storage incidental to movement, except that, for purposes of safety regulations, it does not include any such movement through gathering lines in rural locations or production, refining, or manufacturing facilities or storage or in-plant piping systems associated with any of those facilities.

The provisions of this §8.5 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective February 4, 2009, 34 TexReg 582; amended to be effective August 30, 2010, 35 TexReg 7743.

SUBCHAPTER B. REQUIREMENTS FOR ALL PIPELINES

§8.51. Organization Report.

(a) Each gas and/or liquids company, other than a master meter operator, operating wholly or partially within this state, acting either as principal or as agent for another, and performing operations within the jurisdiction of the Commission, shall have on file with the Commission an approved organization report (Form P-5) and financial security as required by Texas Natural Resources Code, §§91.103-91.1091, and §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements).

(b) Each master meter operator, operating wholly or partially within this state, acting either as principal or as agent for another, and performing operations within the jurisdiction of the Commission, shall have on file with the Commission an approved organization report (Form P-5) as authorized by Texas Utilities Code §121.201(a)(2), but is not required to furnish the financial security required by Texas Natural Resources Code, §91.109(b)(2) if the operation of one or more master metered systems is the only business for which the financial security would otherwise be required.

The provisions of this §8.51 adopted to be effective November 24, 2004, 29 TexReg 10733.

§8.101. Pipeline Integrity Assessment and Management Plans for Natural Gas and Hazardous Liquids Pipelines.

(a) This section does not apply to plastic pipelines.

(b) By February 1, 2002, operators of intrastate transmission lines subject to the requirements of 49 CFR Part 192 or 49 CFR Part 195 shall have designated to the Commission on a system-by-system or segment within each system basis whether the pipeline operator has chosen to use the risk-based analysis pursuant to paragraph (1) of this subsection or the prescriptive plan authorized by paragraph (2) of this subsection. Hazardous liquid pipeline operators using the risk-based plan shall complete at least 50% of the initial assessments by January 1, 2006, and the remainder by January 1, 2011; operators using the prescriptive plan shall complete the initial integrity testing by January 1, 2006, or January 1, 2011, pursuant to the requirements of paragraph (2) of this subsection. Natural gas pipeline operators using the risk-based plan shall complete at least 50% of the initial assessments by December 17, 2007, and the remainder by December 17, 2012; operators using the prescriptive plan shall complete the initial integrity testing by December 17, 2007, or December 17, 2012, pursuant to the requirements of paragraph (2) of this subsection.

(1) The risk-based plan shall contain at a minimum:

(A) identification of the pipelines and pipeline segments or sections in each system covered by the plan;

(B) a priority ranking for performing the integrity assessment of pipeline segments of each system based on an analysis of risks that takes into account:

(i) population density;

(ii) immediate response area designation, which, at a minimum, means the identification of significant threats to the environment (including but not limited to air, land, and water) or to the public health or safety of the immediate response area;

(iii) pipeline configuration;

(iv) prior in-line inspection data or reports;

(v) prior pressure test data or reports;

(vi) leak and incident data or reports;

(vii) operating characteristics such as established maximum allowable operating pressures (MAOP) for gas pipelines or maximum operating pressures (MOP) for liquids pipelines, leak survey results, cathodic protection surveys, and product carried;

(viii) construction records, including at a minimum but not limited to the age of the pipe and the operating history;

(ix) pipeline specifications; and

(x) any other data that may assist in the assessment of the integrity of pipeline segments.

(C) assessment of pipeline integrity using at least one of the following methods appropriate for each segment:

(i) in-line inspection;

(ii) pressure test;

(iii) direct assessment after approval by the director; or

(iv) other technology or assessment methodology not specifically listed in this paragraph after approval by the director.

(D) management methods for the pipeline segments which may include remedial action or increased inspections as necessary; and

(E) periodic review of the pipeline integrity assessment and management plan every 36 months, or more frequently if necessary.

(2) Operators electing not to use the risk-based plan in paragraph (1) of this subsection shall conduct a pressure test or an in-line inspection and take remedial action in accordance with the following schedule:

GAS TRANSMISSION LINES				
Size	**Pressure**	**Class 2, 3, 4**	**Class 1**	**Offshore**
Less than or equal to 8 inches	Less than 100 psig	n/a	n/a	Intervals prescribed by operator
	Greater than 100 psig and less than 20% SMYS	10 year intervals	n/a	Intervals prescribed by operator
	Greater than 20% SMYS	5 year intervals	n/a	Intervals prescribed by operator
Greater than 8 inches	Less than 100 psig	n/a	n/a	Intervals prescribed by operator
	Greater than 100 psig and less than 20% SMYS	5 year intervals	n/a	Intervals prescribed by operator
	Greater than 20% SMYS	5 year intervals	10 year intervals	Intervals prescribed by operator

LIQUIDS PIPELINES				
Hazardous Liquids	**Non Rural**	**Rural**	**Crossing of Navigable Waterways**	**Offshore**
Crude Transmission	5 year intervals	10 year intervals	5 year intervals	Intervals prescribed by operator
Crude Gathering	5 year intervals	n/a	5 year intervals	Intervals prescribed by operator
HVL	5 year intervals	5 year intervals	5 year intervals	Intervals prescribed by operator
Products	5 year intervals	10 year intervals	5 year intervals	Intervals prescribed by operator
Carbon Dioxide	5 year intervals	10 year intervals	5 year intervals	Intervals prescribed by operator

(c) Within 185 days after receipt of notice that an operator's plan is complete, the Commission shall either notify the operator of the acceptance of the plan or shall complete an evaluation of the plan to determine compliance with this section.

(d) After the completion of the assessment required under either plan, the operator shall promptly remove defects that are immediate hazards and, no later than the next test interval, shall mitigate any anomalies identified by the test that could reasonably be predicted to become hazardous defects.

(e) Operators of pipelines for which an integrity assessment was performed prior to April 30, 2001 (the effective date of this rule), shall not be required to implement a new plan as long as the original assessment meets the minimum requirements of this section.

(f) If a pipeline that is not subject to this section undergoes any change in circumstances that results in the pipeline becoming subject to this section, then the operator of such pipeline shall establish integrity of the pipeline pursuant to the requirements of this section prior to any further operation. Such changes include but are not limited to an addition to the pipeline, change in the operating pressure of the pipeline, change from inactive to active status, change in population in the area of the pipeline, or change of operator of the pipeline segment. If a pipeline segment is acquired by a new operator, the pipeline segment can continue to be operated without establishing pipeline integrity as long as the new operator utilizes the prior operator's operation and maintenance procedures for this pipeline segment. If the population in the area of a pipeline segment changes, the pipeline segment can continue to operate without establishing pipeline integrity until such time as the operator determines whether or not the change in population affects the criteria applicable to the integrity management program, but for no longer than the time frames established under 49 CFR Part 192 or 195.

The provisions of this §8.101 adopted to be effective April 30, 2001, 26 TexReg 3214; amended to be effective August 25, 2003, 28 TexReg 6829; amended to be effective November 24, 2004, 29 TexReg 10733; amended to be effective August 28, 2006, 31 TexReg 6715; amended to be effective March 2, 2009, 34 TexReg 1414; amended to be effective August 30, 2010, 35 TexReg 7743.

§8.105. Records. Each pipeline operator shall maintain the following most current record or records for at least the time period prescribed by the following regulations or five years if no other time period is specified:

(1) For gas and LNG pipelines, those records and documents required by 49 CFR Parts 191, 192, 193, and 199, and §8.215 of this chapter (relating to Odorization of Gas).

(2) For liquids pipelines, those records and documents required by 49 CFR Parts 195 and 199.

(3) Activities for which the above listed regulations may require record-keeping include but are not limited to:

(A) all design and installation of new and used pipe, including design pressure calculations, pipeline specifications, specified minimum yield strength and wall-thickness calculations, each valve, fitting, fabricated branch connection, closure, flange connection, station piping, fabricated assembly, and above-ground breakout tank;

(B) all pipeline construction, procedures, training, and inspection pertaining to welding, nondestructive testing, and cathodic protection;

(C) all hydrostatic testing performed on all pipeline segments, components, and tie-ins; and

(D) the performance of the procedures outlined in the operations and maintenance procedure manual.

The provisions of this §8.105 adopted to be effective November 24, 2004, 29 TexReg 10733.

§8.115. New Construction Commencement Report. Except as set forth below, at least 30 days prior to commencement of construction of any installation totaling one mile or more of pipe, each operator shall file with the Commission a report stating the proposed originating and terminating points for the pipeline, counties to be traversed, size and type of pipe to be used, type of service, design pressure, and length of the proposed line on Form PS-48. Each operator shall file a new construction report for the initial construction of a new liquefied petroleum gas distribution system. Each operator of a sour gas pipeline and/or pipeline facilities, as defined in §3.106(b) of this title (relating to Sour Gas Pipeline Facility Construction Permit), shall file a new construction report and Form PS-79, Application for a Permit to Construct a Sour Gas Pipeline Facility. New construction on natural gas distribution or master meter system of less than five miles is exempted from this reporting requirement.

The provisions of this §8.115 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective February 4, 2009, 34 TexReg 582.

§8.125. Waiver Procedure.

(a) Purpose and scope. The Commission considers waiver applications to be properly based on a technical inability to comply with the pipeline safety standards set forth in this chapter, related to the specific configuration, location, operating limitations, or available technology for a particular pipeline. Generally, an application for waiver of a pipeline safety rule is site-specific. Cost is generally not a proper objection to compliance by the operator with the pipeline safety standards set forth in this chapter, and a waiver filed simply to avoid the expense of safety compliance is generally not appropriate.

(b) Filing. Any person may apply for a waiver of a pipeline safety rule or regulation by filing an application for waiver with the Division. Upon the filing of an application for waiver of a pipeline safety rule, the Division shall assign a docket number to the application and shall forward it to the director, and thereafter all documents relating to that application shall include the assigned docket number. An application for a waiver is not an acceptable response to a notice of an alleged violation of a pipeline safety rule. The Division shall not assign a docket number to or consider any application filed in response to a notice of violation of a pipeline safety rule.

(c) Form. The application shall be typewritten on paper not to exceed 8 1/2 inches by 11 inches and shall have margins of at least one inch. The contents of the application shall appear on one side of the paper and shall be double or one and one-half spaced, except that footnotes and lengthy quotations may be single spaced. Exhibits attached to an application shall be the same size as the application or folded to that size.

(d) Content. The application shall contain the following:

(1) the name, business address, and telephone number, and facsimile transmission number and electronic mail address, if available, of the applicant and of the applicant's authorized representative, if any;

(2) a description of the particular operation for which the waiver is sought;

(3) a statement concerning the regulation from which the waiver is sought and the reason for the exception;

(4) a description of the facility at which the operation is conducted, including, if necessary, design and operation specifications, monitoring and control devices, maps, calculations, and test results;

(5) a description of the acreage and/or address upon which the facility and/or operation that is the subject of the waiver request is located. The description shall:

(A) include a plat drawing;

(B) identify the site sufficiently to permit determination of property boundaries;

(C) identify environmental surroundings;

(D) identify placement of buildings and areas intended for human occupancy that could be endangered by a failure or malfunction of the facility or operation;

(E) state the ownership of the real property of the site; and

(F) state under what legal authority the applicant, if not the owner of the real property, is permitted occupancy;

(6) an identification of any increased risks the particular operation would create if the waiver were granted, and the additional safety measures that are proposed to compensate for those risks;

(7) a statement of the reason the particular operation, if the waiver were granted, would not be inconsistent with pipeline safety.

(8) an original signature, in ink, by the applicant or the applicant's authorized representative, if any; and

(9) a list of the names, addresses, and telephone numbers of all affected persons, as defined in §8.5 of this title (relating to Definitions).

(e) Notice.

(1) The applicant shall send a copy of the application and a notice of protest form published by the Commission by certified mail, return receipt requested, to all affected persons on the same date of filing the application with the Division. The notice shall describe the nature of the waiver sought; shall state that affected persons have 30 calendar days from the date of the last publication to file written objections or requests for a hearing with the Division; and shall include the docket number of the application and the mailing address of the Division. The applicant shall file all return receipts with the Division as proof of notice.

(2) The applicant shall publish notice of its application for waiver of a pipeline safety rule once a week for two consecutive weeks in the state or local news section of a newspaper of general circulation in the county or counties in which the facility or operation for which the requested waiver is located. The notice shall describe the nature of the waiver sought; shall state that affected persons have 30 calendar days from the date of the last publication to file written objections or requests for a hearing with the Division; and shall include the docket number of the application and the mailing address of the Division. Within ten calendar days of the date of last publication, the applicant shall file with the Division a publisher's affidavit from each newspaper in which notice was published as proof of publication of notice. The affidavit shall state the dates on which the notice was published and shall have attached to it the tear sheets from each edition of the newspaper in which the notice was published.

(3) The applicant shall give any other notice of the application which the director may require.

(f) Protest or support of waiver application.

(1) Affected persons shall have standing to object to, support, or request a hearing on an application.

(2) A person who objects to, who supports, or who requests a hearing on the application shall file a written objection, statement of support, or request for a hearing with the Division no later than the 30th calendar day after the date the notice of the application

was postmarked or the last date the notice was published in the newspaper in the county in which the person owns or occupies property, whichever is later.

(3) The objection, statement of support, or request for a hearing shall:

(A) state the name, address, and telephone number of the person filing the objection, statement of support, or request for hearing and of every person on whose behalf the objection, statement of support, or request for a hearing is being filed;

(B) include a statement of the facts on which the person filing the protest or statement of support relies to conclude that each person on whose behalf the objection, statement of support, or request for a hearing is being filed is an affected person, as defined in §8.5 of this title (relating to Definitions); and

(C) include a statement of the nature and basis for the objection to or statement of support for the waiver request.

(g) Division review.

(1) The director shall complete the review of the application within 60 calendar days after the application is complete. If an application remains incomplete 12 months after the date the application was filed, such application shall expire and the director shall dismiss without prejudice to refiling.

(A) If the director does not receive any objections or requests for a hearing from any affected person, the director may recommend in writing that the Commission grant the waiver if granting the waiver is not inconsistent with pipeline safety. The director shall forward the file, along with the written recommendation that the waiver be granted, to the Office of General Counsel for the preparation of an order.

(B) The director shall not recommend that the Commission grant the waiver if the application was filed either to correct an existing violation or to avoid the expense of safety compliance. The director shall dismiss with prejudice to refiling an application filed in response to a notice of violation of a pipeline safety rule.

(C) If the director declines to recommend that the Commission grant the waiver, the director shall notify the applicant in writing of the recommendation and the reason for it, and shall inform the applicant of any specific deficiencies in the application.

(2) If the director declines to recommend that the Commission grant the waiver, and if the application was not filed either to correct an existing violation or solely to avoid the expense of safety compliance, the applicant may either:

(A) modify the application to correct the deficiencies and resubmit the application; or

(B) file a written request for a hearing on the matter within ten calendar days of receiving notice of the assistant director's written decision not to recommend that the Commission grant the application.

(h) Hearings.

(1) Within three days of receiving either a timely-filed objection or a request for a hearing, the director shall forward the file to the Office of General Counsel for the setting of a hearing.

(2) Within three days of receiving the file, the Office of General Counsel shall assign a presiding examiner to conduct a hearing as soon as practicable.

(3) The presiding examiner shall mail notice of the hearing by certified mail, return receipt requested, not less than 30 calendar days prior to the date of the hearing to:

(A) the applicant;

(B) all persons who filed an objection or a request for a hearing; and

(C) all other affected persons.

(4) The presiding examiner shall conduct the hearing in accordance with the procedural requirements of Texas Government Code, Chapter 2001 (the Administrative Procedure Act), and Chapter 1 of this title (relating to Practice and Procedure).

(i) Finding requirement. After a hearing, the Commission may grant a waiver of a pipeline safety rule based on a finding or findings that the grant of the waiver is not inconsistent with pipeline safety.

(j) Notice to United States Department of Transportation. Upon a Commission order granting a waiver of a pipeline safety rule, the director shall give written notice to the Secretary of Transportation pursuant to the provisions of 49 United States Code Annotated, §60118(d). The Commission's grant of a waiver becomes effective in accordance with the provisions of 49 United States Code Annotated, §60118(d).

The provisions of this §8.125 adopted to be effective November 24, 2004, 29 TexReg 10733.

§8.130. Enforcement.

(a) Periodic inspection. The Division shall have responsibility for the administration and enforcement of the provisions of this chapter. To this end, the Division shall formulate a plan or program for periodic evaluation of the books, records, and facilities of gas companies and liquids companies operating in Texas on a sampling basis, in order to satisfy the Commission that these companies are in compliance with the provisions of this chapter.

(b) Scope of inspection. Upon reasonable notice, the Division or its authorized representative may, at any reasonable time, inspect the books, files, records, reports, supplemental data, other documents and information, plant, property, and facilities of a gas company or a liquids company to ensure compliance with the provisions of this chapter.

(c) Company obligations.

(1) Each operator, officer, employee, and representative of a gas company or a liquids company operating in Texas shall cooperate with the Division and its authorized representatives in the administration and enforcement of the provisions of this chapter; in the determination of compliance with the provisions of this chapter; and in the investigation of violations, alleged violations, accidents or incidents involving intrastate pipeline facilities.

(2) Each operator, officer, employee, and representative of a gas company or a liquids company operating in Texas shall make readily available all company books, files, records, reports, supplemental data, other documents, and information, and shall make readily accessible all company plant, property, and facilities as the Division or its authorized representative may reasonably require in the administration and enforcement of the provisions of this chapter; in the determination of compliance with the provisions of this chapter; and in the investigation of violations, alleged violations, accidents or incidents involving intrastate pipeline facilities.

The provisions of this §8.130 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective August 30, 2010, 35 TexReg 7743.

§8.135. Penalty Guidelines for Pipeline Safety Violations.

(a) Policy. Improved safety and environmental protection are the desired outcomes of any enforcement action. Encouraging operators to take appropriate voluntary corrective and future protective actions once a violation has occurred is an effective component of the enforcement process. Deterrence of violations through penalty assessments is also a necessary and effective component of the enforcement process. A rule-based enforcement penalty guideline to evaluate and rank pipeline safety-related violations is consistent with the central goal of the Commission's enforcement efforts to promote compliance. Penalty guidelines set forth in this section will provide a framework for more uniform and equitable assessment of penalties throughout the state, while also enhancing the integrity of the Commission's enforcement program.

(b) Only guidelines. This section complies with the requirements of Texas Natural Resources Code, §81.0531(d), and Texas Utilities Code, §121.206(d). The penalty amounts contained in the tables in this section are provided solely as guidelines to be considered by the Commission in determining the amount of administrative penalties for violations of provisions of Texas Natural Resources Code, Title 3, relating to pipeline safety, or of rules, orders or permits relating to pipeline safety adopted under those provisions, and for violations of Texas Utilities Code, §121.201, or a safety standard or other rule prescribed or adopted under that provision.

(c) Commission authority. The establishment of these penalty guidelines shall in no way limit the Commission's authority and discretion to cite violations and assess administrative penalties. The typical minimum penalties listed in this section are for the most common violations cited; however, this is neither an exclusive nor an exhaustive list of violations that the Commission may cite. The Commission retains full authority and discretion to cite violations of Texas Natural Resources Code, Title 3, relating to pipeline safety, or of rules, orders, or permits relating to pipeline safety adopted under those provisions, and for violations of Texas Utilities Code, §121.201, or a safety standard or other rule prescribed or adopted under that provision, and to assess administrative penalties in any amount up to the statutory maximum when warranted by the facts in any case, regardless of inclusion in or omission from this section.

(d) Factors considered. The amount of any penalty requested, recommended, or finally assessed in an enforcement action will be determined on an individual case-by-case basis for each violation, taking into consideration the following factors:

(1) the person's history of previous violations, including the number of previous violations;

(2) the seriousness of the violation and of any pollution resulting from the violation;

(3) any hazard to the health or safety of the public;

(4) the degree of culpability;

(5) the demonstrated good faith of the person charged; and

(6) any other factor the Commission considers relevant.

(e) Typical penalties. Typical penalties for violations of provisions of Texas Natural Resources Code, Title 3, relating to pipeline safety, or of rules, orders, or permits relating to pipeline safety adopted under those provisions, and for violations of Texas Utilities Code, §121.201, or a safety standard or other rule prescribed or adopted under that provision are set forth in Table 1.

Table 1. Typical Penalties

Rule	**Guideline Penalty Amount**

16 TAC §3.70-Pipeline Permits Required	$5,000
16 TAC §8.1-General Applicability and Standards	$5,000
16 TAC §8.51-Organization Report	$5,000
16 TAC §8.101-Pipeline Integrity Assessment and Management Plans	$5,000
16 TAC §8.105-Records	$5,000
16 TAC §8.115-Construction Commencement Report	$5,000
16 TAC §8.201-Pipeline Safety and Regulatory Program Fees	10% of amt. due
16 TAC §8.203-Supplemental Regulations	$5,000
16 TAC §8.205-Written Procedure for Handling Natural Gas Leak Complaints	$5,000
16 TAC §8.206- Risk Based Leak Survey Program	$5,000
16 TAC §8.207-Leak Grading and Repair	$5,000
16 TAC §8.208- Mandatory Removal and Replacement Program	$5,000
16 TAC §8.209- Distribution Facilities Replacements	$5,000
16 TAC §8.210-Reports	$5,000
16 TAC §8.215-Odorization of Gas	$10,000
16 TAC §8.220-Master Metered Systems	$5,000
16 TAC §8.225-Plastic Pipe Requirements	$5,000
16 TAC §8.230-School Piping Testing	$5,000
16 TAC §8.235-Natural Gas Pipelines Public Education and Liaison	$5,000
16 TAC §8.235-Proximity to Public Schools Located within 1,000 Feet	$5,000
16 TAC §8.240-Discontinuance of Service	$10,000
16 TAC §8.301-Records and Reporting	$5,000
16 TAC §8.305-Corrosion Control	$5,000
16 TAC §8.310-Hazardous Liquids and Carbon Dioxide Public Education and Liaison	$5,000
16 TAC §8.315-Hazardous Liquids and Carbon Dioxide Pipeline Located within 1,000 Feet of Public School	$5,000
49 CFR 192.613-Continuing surveillance	$5,000
49 CFR 192.619-Maximum allowable operating pressure	$5,000
49 CFR 192.625-Odorization of gas	$10,000
49 CFR 192 Subpart I- Requirements for Corrosion Control	$5,000
49 CFR 192 Subpart M-Maintenance	$5,000
49 CFR 192 Subpart N-Qualification of Pipeline Personnel	$5,000
49 CFR 192, Subpart O-Pipeline Integrity Management	$5,000
49 CFR 192, Subpart P- Gas Distribution Pipeline Integrity Management	$5,000
49 CFR Part 192-Transportation of Natural and Other Gas by Pipeline	$1,000
49 CFR Part 193-Liquefied Natural Gas Facilities: Federal Safety Standards	$1,000
49 CFR Part 195-Transportation of Hazardous Liquids by Pipeline	$1,000
49 CFR Part 195.401-General Requirements	$5,000
49 CFR Part 195.406-Maximum Operating Pressure	$5,000
49 CFR Part 195.440-Public Awareness	$5,000
49 CFR Part 195.452-Integrity Management	$5,000
49 CFR Part 195 Subpart G-Qualification of Pipeline Personnel	$5,000
49 CFR Part 199-Drug and Alcohol Testing	$1,000

(f) Penalty enhancements for certain violations. For violations that involve threatened or actual pollution; result in threatened or actual safety hazards; or result from the reckless or intentional conduct of the person charged, the Commission may assess an enhancement of the typical penalty, as shown in Table 2. The enhancement may be in any amount in the range shown for each type of violation.

Table 2. Penalty Enhancements

For violations that involve:	Threatened or actual pollution	Threatened or actual safety hazard	Severity of violation or culpability of person

			charged
Bay estuary or marine habitat	$5,000 to $25,000		
Pollution resulting from the violation	$5,000 to $25,000		
Impact to a residential or public area		$5,000 to $25,000	
Hazardous material release		$2,000 to $25,000	
Reportable incident or accident		$5,000 to $25,000	
Exceeding pressure control limits		$5,000 to $25,000	
Any hazard to the health or safety of the public		$5,000 to $25,000	
The seriousness of the violation			$5,000 to $25,000
Death or personal injury			$5,000 to $25,000
Affected area exceeds 100 square feet			$10 per square foot
Reckless conduct of person charged			Up to double the total penalty
Intentional conduct of person charged			Up to triple the total penalty

(g) Penalty enhancements for certain violators. For violations in which the person charged has a history of prior violations within seven years of the current enforcement action, the Commission may assess an enhancement based on either the number of prior violations or the total amount of previous administrative penalties, but not both. The actual amount of any penalty enhancement will be determined on an individual case-by-case basis for each violation. The guidelines in Tables 3 and 4 are intended to be used separately. Either guideline may be used where applicable, but not both.

Table 3. Penalty enhancements based on number of prior violations within seven years

Number of violations or warnings in the seven years prior to action	Guideline Enhancement Amount
One	Double penalty amount
More than two but fewer than five	Triple penalty amount
More than five but fewer than ten	Four times penalty amount
More than ten	Five times penalty amount

Table 4. Guideline Penalty enhancements based on total amount of prior penalties within seven years

Total administrative penalties assessed in the seven years prior to action	Guideline Enhancement amount
Less than $10,000	$1,000
Between $10,001 and $25,000	$2,500
Between $25,001 and $50,000	$5,000
Between $50,001 and $100,000	$10,000
Over $100,000	10% of total amount

(h) Penalty reduction for settlement before hearing. The recommended penalty for a violation may be reduced by up to 50% if the person charged agrees to a settlement before the Commission conducts an administrative hearing to prosecute a violation. Once the hearing is convened, the opportunity for the person charged to reduce the basic monetary penalty is no longer available. The reduction applies to the basic penalty amount requested and not to any requested enhancements.

(i) Demonstrated good faith. In determining the total amount of any penalty requested, recommended, or finally assessed in an enforcement action, the Commission may consider, on an individual case-by-case basis for each violation, the demonstrated good faith of the person charged. Demonstrated good faith includes, but is not limited to, actions taken by the person charged before the filing of an enforcement action to remedy, in whole or in part, a violation or to mitigate the consequences of a violation.

(j) Penalty calculation worksheet. The penalty calculation worksheet shown in Table 5 lists the typical penalty amounts for certain violations; the circumstances justifying enhancements of a penalty and the amount of the enhancement; and the circumstances justifying a reduction in a penalty and the amount of the reduction.

Table 5. Penalty calculation worksheet.

	Violations from Table 1	Typical Penalty Amounts from Table 1	Penalty Tally
1	16 TAC §3.70-Pipeline Permits Required	$5,000	$
2	16 TAC §8.1-General Applicability and Standards	$5,000	$
3	16 TAC §8.51-Organization Report	$5,000	$
4	16 TAC §8.101-Pipeline Integrity Assessment and Management Plans	$5,000	$
5	16 TAC §8.105-Records	$5,000	$
6	16 TAC §8.115-Construction Commencement Report	$5,000	$
7	16 TAC §8.201-Pipeline Safety and Regulatory Program Fees	10% of amt. due	$
8	16 TAC §8.203-Supplemental Regulations	$5,000	$
9	16 TAC §8.205-Written Procedure for Handling Natural Gas Leak Complaints	$5,000	$
10	16 TAC §8.206- Risk Based Leak Survey Program	$5,000	$
11	16 TAC §8.207-Leak Grading and Repair	$5,000	$
12	16 TAC §8.208- Mandatory Removal and Replacement Program	$5,000	$
13	16 TAC §8.209- Distribution Facilities Replacements	$5,000	$
14	16 TAC §8.210-Reports	$5,000	$
15	16 TAC §8.215-Odorization of Gas	$10,000	$
16	16 TAC §8.220-Master Metered Systems	$5,000	$
17	16 TAC §8.225-Plastic Pipe Requirements	$5,000	$
18	16 TAC §8.230-School Piping Testing	$5,000	$
19	16 TAC §8.235-Natural Gas Pipelines Public Education and Liaison	$5,000	$
20	16 TAC §8.235-Proximity to Public Schools Located within 1,000 Feet	$5,000	$
21	16 TAC §8.240-Discontinuance of Service	$10,000	$
22	16 TAC §8.301-Records and Reporting	$5,000	$
23	16 TAC §8.305-Corrosion Control	$5,000	$
24	16 TAC §8.310-Hazardous Liquids and Carbon Dioxide Public Education and Liaison	$5,000	$
25	16 TAC §8.315-Hazardous Liquids and Carbon Dioxide Pipeline Located within 1,000 Feet of Public School	$5,000	$
26	49 CFR 192.613-Continuing surveillance	$5,000	$
27	49 CFR 192.619-Maximum allowable operating pressure	$5,000	$
28	49 CFR 192.625-Odorization of gas	$10,000	$
29	49 CFR 192 Subpart I- Requirements for Corrosion Control	$5,000	$
30	49 CFR 192 Subpart M-Maintenance	$5,000	$
31	49 CFR 192 Subpart N-Qualification of Pipeline Personnel	$5,000	$
32	49 CFR 192, Subpart O-Pipeline Integrity Management	$5,000	$
33	49 CFR 192, Subpart P- Gas Distribution Pipeline Integrity Management	$5,000	$
34	49 CFR Part 192-Transportation of Natural and Other Gas by Pipeline	$1,000	$
35	49 CFR Part 193-Liquefied Natural Gas Facilities: Federal Safety Standards	$1,000	$
36	49 CFR Part 195-Transportation of Hazardous Liquids by Pipeline	$1,000	$
37	49 CFR Part 195.401-General Requirements	$5,000	$
38	49 CFR Part 195.406-Maximum Operating Pressure	$5,000	$
39	49 CFR Part 195.440-Public Awareness	$5,000	$

40	49 CFR Part 195.452-Integrity Management	$5,000	$
41	49 CFR Part 195 Subpart G-Qualification of Pipeline Personnel	$5,000	$
42	49 CFR Part 199-Drug and Alcohol Testing	$1,000	$
43	**Subtotal of typical penalty amounts from Table 1 (lines 1-42, inclusive)**		$
44	**Reduction for settlement before hearing: up to 50% of line 43 amt.**	__________%	$
45	**Subtotal: amount shown on line 43 less applicable settlement reduction from line 44**		$
Penalty enhancement amounts for threatened or actual pollution or safety hazard from Table 2			
46	Bay, estuary, or marine habitat	$5,000-$25,000	$
47	Pollution resulting from the violation	$5,000 to $25,000	$
48	Impact to a residential or public area	$5,000 to $25,000	$
49	Hazardous material release	$2,000-$25,000	$
50	Reportable incident or accident	$5,000-$25,000	$
51	Exceeding pressure control limits	$5,000 to $25,000	$
52	Any hazard to the health or safety of the public	$5,000 to $25,000	$
Penalty enhancements for severity of violation from Table 2			
53	Affected area exceeds 100 square feet	$10/square foot	$
54	**Subtotal: amount on line 45 plus all amounts on lines 46 through 53, inclusive**		$
Penalty enhancements for culpability of person charged from Table 2			
55	Reckless conduct of person charged	double line 54 amt.	$
56	Intentional conduct of person charged	triple line 54 amt.	$
Penalty enhancements for number of prior violations within past seven years from Table 3			
57	One	$1,000	$
58	Two	$2,000	$
59	Three	$3,000	$
60	Four	$4,000	$
61	Five or more	$5,000	$
Penalty enhancements for amount of penalties within past seven years from Table 4			
62	Less than $10,000	$1,000	$
63	Between $10,000 and $25,000	$2,500	$
64	Between $25, 000 and $50,000	$5,000	$
65	Between $50,000 and $100,00	$10,000	$
66	Over $100,000	10% of total amt.	$
67	**Subtotal: amount on line 54 plus amounts on lines 55 and/or 56 plus the amount shown on any one line from 57 through 66, inclusive**		$
68	**Reduction for demonstrated good faith of person charged**		$
69	**TOTAL PENALTY AMOUNT: amount on line 67 less any amount shown on line 68**		$

The provisions of this §8.135 adopted to be effective February 4, 2009, 34 TexReg 582; amended to be effective August 27, 2012, 37 TexReg 6554.

SUBCHAPTER C. REQUIREMENTS FOR NATURAL GAS PIPELINES ONLY

§8.201. Pipeline Safety and Regulatory Program Fees.

(a) Application of fees. Pursuant to Texas Utilities Code, §121.211, the Commission establishes a pipeline safety and regulatory program fee, to be assessed annually against operators of natural gas distribution pipelines and pipeline facilities and natural gas master metered pipelines and pipeline facilities subject to the Commission's jurisdiction under Texas Utilities Code, Title 3. The total amount of revenue estimated to be collected under this section does not exceed the amount the Commission estimates to be necessary to recover the costs of administering the pipeline safety and regulatory programs under Texas Utilities Code, Title 3, excluding costs that are fully funded by federal sources for any fiscal year.

(b) Natural gas distribution systems. The Commission hereby assesses each operator of a natural gas distribution system an annual pipeline safety and regulatory program fee of $1.00 for each service (service line) in service at the end of each calendar year as reported by each system operator on the U.S. Department of Transportation (DOT) Gas Distribution Annual Report, Form PHMSA F7100.1-1 due on March 15 of each year.

(1) Each operator of a natural gas distribution system shall calculate the annual pipeline safety and regulatory program total to be paid to the Commission by multiplying the $1.00 fee by the number of services

listed in Part B, Section 3, of Form PHMSA F7100.1-1, due on March 15 of each year.

(2) Each operator of a natural gas distribution system shall remit to the Commission on March 15 of each year the amount calculated under paragraph (1) of this subsection.

(3) Each operator of a natural gas distribution system shall recover, by a surcharge to its existing rates, the amount the operator paid to the Commission under paragraph (1) of this subsection. The surcharge:

(A) shall be a flat rate, one-time surcharge;

(B) shall not be billed before the operator remits the pipeline safety and regulatory program fee to the Commission;

(C) shall be applied in the billing cycle or cycles immediately following the date on which the operator paid the Commission;

(D) shall not exceed $1.00 per service or service line; and

(E) shall not be billed to a state agency, as that term is defined in Texas Utilities Code, §101.003.

(4) No later than 90 days after the last billing cycle in which the pipeline safety and regulatory program fee surcharge is billed to customers, each operator of a natural gas distribution system shall file with the Commission's Gas Services Division and the Pipeline Safety Division a report showing:

(A) the pipeline safety and regulatory program fee amount paid to the Commission;

(B) the unit rate and total amount of the surcharge billed to each customer;

(C) the date or dates on which the surcharge was billed to customers; and

(D) the total amount collected from customers from the surcharge.

(5) Each operator of a natural gas distribution system that is a utility subject to the jurisdiction of the Commission pursuant to Texas Utilities Code, Chapters 101 - 105, shall file a generally applicable tariff for its surcharge in conformance with the requirements of §7.315 of this title, relating to Filing of Tariffs.

(6) Amounts recovered from customers under this subsection by an investor-owned natural gas distribution system or a cooperatively owned natural gas distribution system shall not be included in the revenue or gross receipts of the system for the purpose of calculating municipal franchise fees or any tax imposed under Subchapter B, Chapter 182, Tax Code, or under Chapter 122, nor shall such amounts be subject to a sales and use tax imposed by Chapter 151, Tax Code, or Subtitle C, Title 3, Tax Code.

(c) Natural gas master meter systems. The Commission hereby assesses each natural gas master meter system an annual pipeline safety and regulatory program fee of $100 per master meter system.

(1) Each operator of a natural gas master meter system shall remit to the Commission the annual pipeline safety and regulatory program fee of $100 per master meter system no later than June 30 of each year.

(2) The Commission shall send an invoice to each affected natural gas master meter system operator no later than April 30 of each year as a courtesy reminder. The failure of a natural gas master meter system operator to receive an invoice shall not exempt the natural gas master meter system operator from its obligation to remit to the Commission the annual pipeline safety and regulatory program fee on June 30 each year.

(3) Each operator of a natural gas master meter system shall recover as a surcharge to its existing rates the amounts paid to the Commission under paragraph (1) of this subsection.

(4) No later than 90 days after the last billing cycle in which the pipeline safety and regulatory program fee surcharge is billed to customers, each natural gas master meter system operator shall file with the Commission's Gas Services Division and the Pipeline Safety Division a report showing:

(A) the pipeline safety and regulatory program fee amount paid to the Commission;

(B) the unit rate and total amount of the surcharge billed to each customer;

(C) the date or dates on which the surcharge was billed to customers; and

(D) the total amount collected from customers from the surcharge.

(d) Late payment penalty. If the operator of a natural gas distribution system or a natural gas master meter system does not remit payment of the annual pipeline safety and regulatory program fee to the Commission within 30 days of the due date, the Commission shall assess a late payment penalty of 10 percent of the total assessment due under subsection (b) or (c) of this section, as applicable, and shall notify the operator of the total amount due to the Commission.

The provisions of this §8.201 adopted to be effective September 8, 2003, 28 TexReg 7682; amended to be effective November 24, 2004, 29 TexReg 10733; amended to be effective May 15, 2005, 30 TexReg 2849; amended to be effective December 19, 2005, 30 TexReg 8428; amended to be effective April 18, 2007, 32 TexReg 2136; amended to be effective November 12, 2007, 32 TexReg 8121; amended to be effective September 21, 2009, 34 TexReg 6446; amended to be effective August 30, 2010, 35 TexReg 7743; amended to be effective November 14, 2011, 36 TexReg 7663; amended to be effective November 11, 2013, 38 TexReg 7947.

§8.203. Supplemental Regulations. The following provisions supplement the regulations appearing in 49

CFR Part 192, adopted under §8.1(b) of this chapter (relating to General Applicability and Standards).

(1) Section 192.455(b) is supplemented by the following language after the first sentence: "Tests, investigation, or experience must be backed by documented proof to substantiate results and determinations."

(2) Section 192.457 is supplemented:

(A) by the following language in subsection (b)(3): "(3) Bare or coated distribution lines. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other effective means, documented by data substantiating results and determinations";

(B) by adding the following subsection: "(d) When a condition of active external corrosion is found, positive action must be taken to mitigate and control the effects of the corrosion. Schedules must be established for application of corrosion control. Monitoring effectiveness must be adequate to mitigate and control the effects of the corrosion prior to its becoming a public hazard or endangering public safety."

(3) Section 192.465 is supplemented:

(A) by the following language after the first sentence of subsection (a): "Test points (electrode locations) used when taking pipe-to-soil readings for determining cathodic protection shall be selected so as to give representative pipe-to-soil readings. Test points (electrode locations) over or near an anode or anodes shall not, by themselves, be considered representative readings";

(B) by the following subsection: "(f) When leak detection surveys are used to determine areas of active corrosion or re-evaluate unprotected pipelines, the survey frequency must be increased to monitor the corrosion rate and control the condition. The detection equipment used must have sensitivity adequate to detect gas concentration below the lower explosive limit and be suitable for such use."

(4) Section 192.475(a) is supplemented by the following language at the end: "Corrosive gas" means a gas which, by chemical reaction with the pipe to which it is exposed, usually metal, produces a deterioration of the material."

(5) Section 192.479 is supplemented by the following subsection: "(d) 'atmospheric corrosion' means aboveground corrosion caused by chemical or electrochemical reaction between a pipe material, usually a metal, and its environment, that produces a deterioration of the material."

The provisions of this §8.203 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective February 4, 2009, 34 TexReg 582.

§8.205. Written Procedure for Handling Natural Gas Leak Complaints. Each gas company shall have written procedures which shall include at a minimum the following provisions:

(1) a procedure or method for receiving leak complaints or reports, or both, on a 24-hour, seven day per week basis;

(2) a requirement to make and maintain a written record of all calls received and actions taken;

(3) a requirement that supervisory review of leak complaints must be completed and documented by 10:00 a.m. of the next business day for calls received by midnight on the previous day;

(4) standards for training and equipping personnel used in the investigation of leak complaints or reports, or both;

(5) procedures for locating the source of a leak and determining the degree of hazard involved;

(6) a chain of command for service personnel to follow if assistance is required in determining the degree of hazard;

(7) instructions to be issued by service personnel to customers or the public or both, as necessary, after a leak is located and the degree of hazard determined.

The provisions of this §8.205 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective February 4, 2009, 34 TexReg 582.

§8.206. Risk-Based Leak Survey Program.

(a) Effective September 1, 2008, this section applies to each operator of a gas distribution system that is subject to the requirements of 49 CFR Part 192.

(b) No later than March 1, 2009, each operator shall have completed and submitted to the Commission either a prescriptive or a risk-based program for leak surveys for its pipeline systems that complies with the requirements of this section. Such program shall require a designation on a system by system basis or by segments within each system whether the operator has chosen to use the risk based leak survey program that complies with the requirements of subsections (c) through (f) of this section or the prescriptive leak survey program that complies with the requirements of subsection (g) of this section. Within 185 days after receipt of notice that an operator's plan is complete, the Commission shall either notify the operator of the acceptance of the plan or shall complete an evaluation of the plan to determine compliance with this section.

(c) Each operator shall create a risk model on which to base its leak survey program to identify those systems or segments within systems that pose the greatest hazard and thus will be inspected for leaks more frequently. The risk model shall identify risk factors and determine the degree of hazard associated with those risk factors. The operator shall establish the leak survey frequency based on the degree of hazard for each system or segment within a system.

(d) Each operator shall periodically re-evaluate each pipeline system or system segment and update its leak survey inspection program to address any changes that may be identified through the monitoring of the pipeline system in accordance with the requirements imposed by 49 CFR §192.613 (relating to Continuing Surveillance). Each operator shall review its leak survey inspection program at least every three years and within 30 days in the following circumstances:

(1) to add a new system or segment being put into operation; or

(2) if, for any system or segment, there has been a ten percent increase in the number of leaks being upgraded or a ten percent increase in the number of unrepaired leaks.

(e) Based on the particular circumstances and conditions, an increased frequency beyond that required by 49 CFR §192.723(b)(1) and (2), may be warranted. Surveys should be conducted more frequently in those areas with the greatest potential for leakage and where leakage could be expected to create a hazard. Each operator should consider the following factors in establishing an increased frequency of leakage surveys:

(1) pipe location, which means proximity to buildings or other structures and the type and use of the buildings and proximity to areas of concentrations of people;

(2) composition and nature of the piping system, which means the age of the pipe, materials, type of facilities, operating pressures, leak history records, and other studies;

(3) the corrosion history of the pipeline, which means known areas of significant corrosion or areas where corrosive environments are known to exist, cased crossings of roads, highways, railroads, or other similar locations where there is susceptibility to unique corrosive conditions;

(4) environmental factors that affect gas migration, which means conditions that could increase the potential for leakage or cause leaking gas to migrate to an area where it could create a hazard, such as extreme weather conditions or events (significant amounts or extended periods of rainfall, extended periods of drought, unusual or prolonged freezing weather, hurricanes, etc.), particular soil conditions, unstable soil or areas subject to earth movement, subsidence, or extensive growth of tree roots around pipeline facilities that can exert substantial longitudinal force on the pipe and nearby joints; and

(5) any other condition known to the operator that has significant potential to initiate a leak or to permit leaking gas to migrate to an area where it could result in a hazard, which could include construction activity near the pipeline, wall-to-wall pavement, trenchless excavation activities (e.g., boring), blasting, large earth-moving equipment, heavy traffic, increase in operating pressure, and other similar activities or conditions.

(f) The assignment of inspection priorities is based on the degree of hazard associated with the risk factors assigned to the pipeline system or segments within a system. The determination of leak survey frequency is determined by classifying each pipeline segment based on its degree of hazard associated with each risk factor. Each operator shall establish its own risk ranking for pipeline segments to determine the frequency of leakage surveys. Based on a ranking from high to low, each operator shall schedule leak inspections for a given pipeline system or segment within a system on a time interval necessary to address the risks. The time interval may range from quarterly to every five years.

(g) Operators electing to use a prescriptive leak survey program shall conduct leak surveys no less frequently than:

(1) annually for all systems within a business district;

(2) every five years for non-business district polyethylene systems or segments within a system;

(3) every three years for all other non-business district cathodically protected steel systems or segments within a system; and

(4) every two years for all other non-business district systems or segments within a system.

The provisions of this §8.206 adopted to be effective September 1, 2008, 33 TexReg 4868.

§8.207. Leak Grading and Repair.

(a) Purpose and qualifications. Operators shall have until March 1, 2009, to repair Grade 2 leaks identified prior to September 1, 2008, and shall have until September 1, 2011, to repair Grade 3 leaks identified prior to September 1, 2008. For all leaks reported on or after September 1, 2008, operators shall comply with the requirements of this section.

(1) The purpose of the leak grading system is to determine the degree or extent of the potential hazard resulting from gas leakage and to prescribe remedial actions. Each operator shall promptly respond to any notification of a gas leak or gas odor or any notification of damage to facilities by excavators or other outside sources.

(2) Each operator shall ensure that leak grading is made only by those individuals who possess training, experience, and knowledge in the field of leak classification and investigation, including extensive

association with actual leakage work. The judgment of these individuals, based upon all pertinent information and a complete leakage investigation at the scene, shall form the basis for the leak grade determination. Each operator shall ensure that its leak detection equipment is properly calibrated.

(b) Grade 1 leaks.

(1) A Grade 1 leak is an existing or probable hazard to persons or property and requires the operator to take action immediately to eliminate the hazard and make repairs. A Grade 1 leak includes but is not limited to:

(A) any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard;

(B) escaping gas that has ignited;

(C) any indication of gas, which has migrated into or under a building, or into a tunnel;

(D) any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building;

(E) any reading of 80% lower explosive limit (LEL) or greater in a confined space;

(F) any reading of 80% LEL or greater in small substructures, other than gas associated substructures, from which gas would likely migrate to the outside wall of a building; or

(G) any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.

(2) A Grade 1 leak requires that the operator take prompt action to eliminate the hazardous conditions. The prompt action may require one or more of the following:

(A) implementing an emergency plan (49 CFR §192.615);

(B) evacuating premises;

(C) blocking off an area;

(D) rerouting traffic;

(E) eliminating sources of ignition;

(F) venting the area by removing manhole covers, barholing, installing vent holes, or other means;

(G) stopping the flow of gas by closing valves or other means; or

(H) notifying emergency responders.

(c) Grade 2 leaks.

(1) A Grade 2 leak is non-hazardous at the time of detection, but requires the operator to schedule repair based on probable future hazard. A Grade 2 leak, because of its location and magnitude, can be scheduled for repair on a normal routine basis with periodic reinspection as necessary. Each operator shall re-evaluate every Grade 2 leak at least once every 30 days until repaired or cleared.

(2) Each operator shall repair within six months of detection any leak:

(A) with a reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak;

(B) with a reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 Leak;

(C) with a reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard;

(D) with a reading between 20% LEL and 80% LEL in a confined space;

(E) with a reading on a pipeline operating at 30 percent SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak;

(F) with a reading of 80% LEL, or greater, in gas associated substructures; and

(G) which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

(3) Grade 2 leaks vary greatly in degree of potential hazard. Some Grade 2 leaks, when evaluated by the criteria in this subsection, may require a scheduled repair within the next five working days. Others will require repair within 30 days. In determining the repair priority, each operator shall consider criteria such as the following:

(A) the amount and migration of gas;

(B) the proximity of gas to buildings and subsurface structures;

(C) the extent of pavement; and

(D) soil type and conditions, such as frost cap, moisture, and natural venting.

(4) Each operator shall take action ahead of ground freezing or other adverse changes in venting conditions with respect to any leak which, under frozen or other adverse soil conditions, would likely allow gas to migrate to the outside wall of a building.

(d) Grade 3 leaks.

(1) A Grade 3 leak is non-hazardous at the time of detection and reasonably can be expected to remain non-hazardous. Each operator shall repair a Grade 3 leak within 36 months of detection.

(2) Each operator shall re-evaluate each Grade 3 leak during the next scheduled survey, or within 15 months of date reported, whichever occurs first, until the leak is cleared, repaired, or re-graded. A leak requiring re-evaluation at periodic intervals includes any reading:

(A) of less than 80% LEL in small, gas-associated substructures;

(B) under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building; and

(C) of less than 20% LEL in a confined space.

(e) Post-repair inspections.

(1) A leak is considered to be effectively repaired when an operator obtains a gas concentration reading of 0%.

(2) For a repaired leak with a gas concentration reading greater than 0% at the time of repair, an operator shall conduct a post-repair leak inspection within 30 days after the repair to determine whether the leak has been effectively repaired. If the second post-repair inspection shows a gas concentration reading greater than 0%, the operator shall continue conducting post-repair leak inspections every 30 days until there is a gas concentration reading of 0%. If after six inspections have been performed the operator is unable to obtain a gas concentration reading of 0%, then the operator shall create a new leak report with a new leak grade determination.

(3) Post-repair inspections are not required for leak repairs completed by the replacement or insertion of an entire length of pipe or service line, or for the repair of leakage caused by excavator or third-party damage, provided a complete re-evaluation of the leak area after completion of repairs verifies that no further indications of leakage exist.

(4) Remedial measures such as lubrication of valves or tightening of packing nuts on valves which seal leaks are considered to be routine maintenance work and do not require a post-repair inspection.

(f) Upgrading. When an operator upgrades a leak to a higher grade, the time period for repair is the remaining time based on its original classification or the time allowed for repair under its new grade, whichever is less. This requirement does not apply to leaks that, at the time of discovery, an operator has classified at a lower grade pending a further, more complete investigation of the leak hazard area.

(g) Table. The following table provides a concise reference for leak grading and leak repair deadlines.

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
1	A leak that represents an existing or probable hazard to persons or property, and requires immediate repair.	Requires immediate repair. Requires prompt action to eliminate the hazardous conditions. The prompt action in some instances may require one or more of the following: ▪ Implementation an emergency plan (§192.615). ▪ Evacuating premises. ▪ Blocking off an area. ▪ Rerouting traffic. ▪ Eliminating sources of ignition. ▪ Venting the area by removing manhole covers, barholing, installing vent holes, or other means. ▪ Stopping the flow of gas by closing valves or other means. ▪ Notifying emergency responders.	▪ Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard. ▪ Escaping gas that has ignited. ▪ Any indication of gas, which has migrated into or under a building, or into a tunnel. ▪ Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building. ▪ Any reading of 80% LEL, or greater, in a confined space. ▪ Any reading of 80% LEL, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building. ▪ Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.
2	A leak that is recognized as being non-hazardous at the time of detection, but requires scheduled repair based on probable future hazard	Leaks shall be repaired or cleared within six months from the date the leak was reported. In determining the repair priority, criteria such as the following should be considered: ▪ Amount and migration of gas. ▪ Proximity of gas to buildings and subsurface structures. ▪ Extent of pavement. ▪ Soil type, and soil conditions (such as frost cap, moisture and natural venting). Grade 2 leaks should be reevaluated at least once every 30 days until cleared. Grade 2 leaks vary greatly in degree of potential hazard. Some Grade 2 leaks, when evaluated by the above criteria, may require a scheduled repair within the next five working days. Others will require repair within 30 days. During the working day on which the leak is discovered, these situations should be brought to the attention of the individual responsible for scheduling leak repair. On the other hand, many Grade 2 leaks, because of their location and magnitude, can be scheduled for repair on a normal	Leaks Requiring Action Ahead of Ground Freezing or Other Adverse Changes in Venting Conditions. Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building. Leaks Requiring Action Within Six Months ▪ Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak. ▪ Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 Leak. ▪ Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard. ▪ Any reading between 20% LEL and 80% LEL in a confined space. ▪ Any reading on a pipeline operating at 30 percent SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak. ▪ Any reading of 80% LEL, or greater, in gas associated substructures. ▪ Any leak which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
		routine basis with periodic reinspection as necessary.	repair.
3	A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.	These leaks should be reevaluated during the next scheduled survey, or within 15 months of date reported, whichever occurs first, until the leak is cleared, re-graded, or repaired within 36 months.	Leaks Requiring Reevaluation at Periodic Intervals ▪ Any reading of less than 80% LEL in small gas associated substructures ▪ Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building. ▪ Any reading of less than 20% LEL in a confined space.

The provisions of this §8.207 adopted to be effective September 1, 2008, 33 TexReg 4868.

§8.208. Mandatory Removal and Replacement Program.

(a) Effective September 1, 2008, this section applies to each operator of a gas distribution system that is subject to the requirements of 49 CFR Part 192.

(b) For leaks identified on any underground compression coupling used to mechanically join steel pipe, each operator shall either replace the leaking compression coupling or repair it using a sleeve welded over the compression coupling.

(c) Each operator shall repair or replace any compression coupling used to mechanically join steel pipe that is exposed during operation and maintenance activities unless the operator can determine the coupling was installed after 1980.

(d) For leaks identified on any underground compression coupling used to mechanically join plastic pipe, each operator shall remove and/or replace the leaking compression coupling.

(e) For any other compression coupling used to join plastic pipe that is exposed during operation and maintenance activities, each operator shall:

(1) For plastic pipe two inches or less in diameter, replace or remove such coupling unless the operator can determine that the coupling is designated as an ASTM (American Society for Testing and Materials) D2513 Category 1 type fitting.

(2) For plastic pipe greater than two inches in diameter, replace or remove such coupling unless the operator can determine that the coupling is designated as an ASTM D2513 Category 1 or Category 3 type fitting.

(f) Each operator shall remove and replace all compression couplings at currently known service riser installations, identifiable by a meter number or a street address, if they are not manufactured and installed in accordance with ASTM D2513 for Category 1 fittings.

(g) Each operator shall complete the removal and replacement of such compression couplings by November 30, 2009.

(h) Any coupling installed on plastic pipe after September 1, 2008, shall be designed to meet the requirements of ASTM D2513 Category 1.

(i) Any coupling installed on steel pipe after September 1, 2008, shall be designed to meet the requirements of 49 CFR Part 192, §192.273.

(j) Beginning November 1, 2008, and every six months thereafter until all compression couplings on the operator's system subject to subsection (f) of this section have been removed and replaced, each operator shall file with the division a progress report showing the number of service riser installations checked, the condition of the coupling, and the total number of compression couplings replaced for that reporting period.

The provisions of this §8.208 adopted to be effective September 1, 2008, 33 TexReg 4868.

§8.209. Distribution Facilities Replacements.

(a) This section applies to each operator of a gas distribution system that is subject to the requirements of 49 CFR Part 192. This section prescribes the minimum requirements by which all operators will develop and implement a risk-based program for the removal or replacement of distribution facilities, including steel service lines, in such gas distribution systems. The risk-based program will work in conjunction with the Distribution Integrity Management Program (DIMP) using scheduled replacements to manage identified risks associated with the integrity of distribution facilities.

(b) Each operator must make joints on below-ground piping that meets the following requirements:

(1) Joints on steel pipe must be welded or designed and installed to resist longitudinal pullout or thrust forces per 49 CFR §192.273.

(2) Joints on plastic pipe must be fused or designed and installed to resist longitudinal pullout or thrust forces per ASTM D2513-Category 1.

(c) No later than August 1, 2011, each operator must establish and submit to the Pipeline Safety Division for review and approval the operator's written procedures for implementing the requirements of this section. Each operator must develop a risk-based program to determine the relative risks and their associated consequences within each pipeline system or segment. Each operator that determines that steel service lines are the greatest risk must conduct the steel service line leak repair analysis set forth in subsection (d) of this section and use the prescriptive model in subsection (f) of this section for the replacement of those steel service lines. Within 90 days after receipt of an operator's written procedures, the Pipeline Safety Division must either notify the operator of the acceptance of the plan or complete an evaluation of the plan to determine compliance with this section. If the Pipeline Safety Division determines that an operator's procedures do not comply with the requirements of this section, the operator must modify its procedures as directed by the Pipeline Safety Division.

(d) In developing its risk-based program, each operator must develop a risk analysis using data collected under its DIMP and the data submitted on the PS-95 to determine the risks associated with each of the operator's distribution systems and establish its own risk ranking for pipeline segments and facilities to determine a prioritized schedule for service line or facility replacement. The operator must support the analysis with data, collected to validate system integrity, that allow for the identification of segments or facilities within the system that have the highest relative risk ranking or consequence in the event of a failure. The operator must identify in its risk-based program the distribution piping, by segment, that poses the greatest risk to the operation of the system. In addition, each operator that determines that steel service lines are the greatest risk must conduct a steel service line leak repair analysis to determine the leak repair rate for steel service lines. The leak repair rate for below-ground steel service lines is determined by dividing the annualized number of below-ground leaks repaired on steel service lines (excluding third-party leaks and leaks on steel service lines removed or replaced under this section) by the total number of steel service lines as reported on PHMSA Form F 7100.1-1, the Gas Distribution System Annual Report. Until the Commission has collected three full calendar years of data submitted on the PS-95, operators may use two calendar years of data to perform the steel service line leak repair analysis. Once the Commission has collected three full calendar years of data submitted on the PS-95, each operator that determines that steel service lines are the greatest risk must conduct the steel service line leak repair analysis using the most recent three calendar years of data reported to the Commission on Form PS-95.

(e) Each operator must create a risk model that will identify by segment those lines that pose the highest risk ranking or consequence of failure. The determination of risk is based on the degree of hazard associated with the risk factors assigned to the pipeline segments or facilities within each of the operator's distribution systems. The priority of service line or facility replacement is determined by classifying each pipeline segment or facility based on its degree of hazard associated with each risk factor. Each operator must establish its own risk ranking for pipeline segments or facilities to determine the priority for necessary service line or facility replacements. Each operator should include the following factors in developing its risk analysis:

(1) pipe location, including proximity to buildings or other structures and the type and use of the buildings and proximity to areas of concentrations of people;

(2) composition and nature of the piping system, including the age of the pipe, materials, type of facilities, operating pressures, leak history records, prior leak grade repairs, and other studies;

(3) corrosion history of the pipeline, including known areas of significant corrosion or areas where corrosive environments are known to exist, cased crossings of roads, highways, railroads, or other similar locations where there is susceptibility to unique corrosive conditions;

(4) environmental factors that affect gas migration, including conditions that could increase the potential for leakage or cause leaking gas to migrate to an area where it could create a hazard, such as extreme weather conditions or events (significant amounts or extended periods of rainfall, extended periods of drought, unusual or prolonged freezing weather, hurricanes, etc.); particular soil conditions; unstable soil; or areas subject to earth movement, subsidence, or extensive growth of tree roots around pipeline facilities that can exert substantial longitudinal force on the pipe and nearby joints; and

(5) any other condition known to the operator that has significant potential to initiate a leak or to permit leaking gas to migrate to an area where it could result in a hazard, including construction activity near the pipeline, wall-to-wall pavement, trenchless excavation activities (e.g., boring), blasting, large earth-moving equipment, heavy traffic, increase in operating pressure, and other similar activities or conditions.

(f) This subsection applies to operators that determine under subsection (c) of this section that steel service lines are the greatest risk. Based on the results of the steel service line leak repair analysis under subsection (d) of this section, each operator must categorize each segment and complete the removal and replacement of steel service lines by segment according to the risk ranking established pursuant to subsection (e) of this section as follows:

(1) a segment with an annualized steel service line leak rate of 7.5% or greater is a Priority 1 segment and an operator must complete the removal or replacement by June 30, 2013;

(2) a segment with an annualized steel service line leak rate of 5% or greater but less than 7.5% is a Priority 2 segment and an operator must remove or replace no less than 10% of the original inventory per year; and

(3) a segment with an annualized steel service line leak rate of less than 5% is a Priority 3 segment. An operator is not required to remove or replace any Priority 3 segments; however, upon discovery of a leak on a Priority 3 segment, the operator must remove or replace rather than repair those lines except as outlined in subsection (g) of this section.

(g) For those steel service lines that must remain in service because of specific operational conditions or requirements, each operator must determine if an integrity risk exists on the segment, and if so, must replace the segment with steel as part of the integrity management plan.

(h) Unless otherwise approved in an operator's risk-based plan, all replacement programs require a minimum annual replacement of 5% of the pipeline segments or facilities posting the greatest risk and identified for replacement pursuant to this section. Each operator with steel service lines subject to subsection (f) of this section must establish a schedule for the replacement of steel service lines or other distribution facilities according to the risk ranking established as part of the operator's risk-based program and must submit the schedule to the Pipeline Safety Division for review and approval or amendment under subsection (c) of this section.

(i) In conjunction with the filing of the pipeline safety and regulatory program fee pursuant to §8.201 of this title (relating to Pipeline Safety and Regulatory Program Fees) and no later than March 15 of each year, each operator must file with the Pipeline Safety Division:

(1) by System ID, a list of the steel service line or other distribution facilities replaced during the prior calendar year; and

(2) the operator's proposed revisions to its risk-based program and proposed work plan for removal or replacement for the current calendar year, the implementation of which is subject to review and amendment by the Pipeline Safety Division. Each operator must notify the Pipeline Safety Division of any revisions to the proposed work plan and, if requested, provide justification for such revision. Within 45 days after receipt of an operator's proposed revisions to its risk-based plan and work plan, the Pipeline Safety Division will notify the operator either of the acceptance of the risk-based program and work plan or of the necessary modifications to the risk-based program and work plan.

(j) Each operator of a gas distribution system that is subject to the requirements of §7.310 of this title (relating to System of Accounts) may use the provisions of this subsection to account for the investment and expense incurred by the operator to comply with the requirements of this section.

(1) The operator may:

(A) establish one or more designated regulatory asset accounts in which to record any expenses incurred by the operator in connection with acquisition, installation, or operation (including related depreciation) of facilities that are subject to the requirements of this section;

(B) record in one or more designated plant accounts capital costs incurred by the operator for the installation of facilities that are subject to the requirements of this section;

(C) record interest on the balance in the designated distribution facility replacement accounts based on the pretax cost of capital last approved for the utility by the Commission. The utility's pre-tax cost of capital may be adjusted and applied prospectively if the Commission establishes a new pre-tax cost of capital for the utility in a future proceeding;

(D) reduce balances in the designated distribution facility replacement accounts by the amounts that are included in and recovered though rates established in a subsequent Statement of Intent filing or other rate adjustment mechanism; and

(E) use the presumption set forth in §7.503 of this title (relating to Evidentiary Treatment of Uncontroverted Books and Records of Gas Utilities) with respect to investment and expense incurred by a gas utility for distribution facilities replacement made pursuant to this section.

(2) This subsection does not render any final determination of the reasonableness or necessity of any investment or expense.

The provisions of this §8.209 adopted to be effective March 14, 2011, 36 TexReg 1658; amended to be effective November 14, 2011, 36 TexReg 7663.

§8.210. Reports.

(a) Accident, leak, or incident report.

(1) Telephonic report. At the earliest practical moment or within two hours following discovery, a gas company shall notify the Commission by telephone of

any event that involves a release of gas from its pipelines defined as an incident in 49 CFR Part 191.3.

(2) The telephonic report shall be made to the Commission's 24-hour emergency line at (512) 463-6788 and shall include the following:

(A) the operator or gas company's name;

(B) the location of the leak or incident;

(C) the time of the incident or accident;

(D) the fatalities and/or personal injuries;

(E) the phone number of the operator;

(F) the telephone number of the operator's on-site person;

(G) estimated property damage, including the cost of gas lost, to the operator, others, or both; and

(H) any other significant facts relevant to the accident or incident. Ignition, explosion, rerouting of traffic, evacuation of any building, and media interest are included as significant facts.

(3) Written report.

(A) Following the initial telephonic report for accidents, leaks, or incidents described in paragraph (1) of this subsection, the operator who made the telephonic report shall submit to the Commission a written report summarizing the accident or incident. The report shall be submitted as soon as practicable within 30 calendar days after the date of the telephonic report. The written report shall be made on forms supplied by the Department of Transportation. For reports submitted electronically to the Department of Transportation, the operator shall forward a copy of the report and confirmation to the Division or electronically to safety@rrc.state.tx.us. For reports not submitted electronically to the Department of Transportation, the operator shall send to the Division an original signed report form.

(B) The written report is not required to be submitted for master metered systems.

(C) The Commission may require an operator to submit a written report for an accident or incident not otherwise required to be reported.

(b) Pipeline safety annual reports.

(1) Except as provided in paragraph (2) of this subsection, each gas company shall submit an annual report for its intrastate systems in the same manner as required by 49 CFR Part 191. The report shall be submitted to the Division on forms supplied by the Department of Transportation not later than March 15 of a year for the preceding calendar year. For reports submitted electronically to the Department of Transportation, the operator may forward a copy of the report and confirmation to the Division or electronically to safety@rrc.state.tx.us. For reports not submitted electronically to the Department of Transportation, the operator shall send to the Division an original signed report form.

(2) The annual report is not required to be submitted for:

(A) a petroleum gas system, as that term is defined in 49 CFR 192.11, which serves fewer than 100 customers from a single source; or

(B) a master metered system.

(c) Safety related condition reports. Each gas company shall submit to the Division in writing a safety-related condition report for any condition outlined in 49 CFR 191.23.

(d) Offshore pipeline condition report. Within 60 days of completion of underwater inspection, each operator shall file with the Division a report of the condition of all underwater pipelines subject to 49 CFR 192.612(a). The report shall include the information required in 49 CFR 191.27.

(e) Leak Reporting. For purposes of this subsection, the term "leak" includes all underground leaks, all hazardous above ground leaks, and all non-hazardous above ground leaks that cannot be eliminated by lubrication, adjustment, or tightening. Each operator of a gas distribution system, of a regulated plastic gas gathering line, or of a plastic gas transmission line shall submit to the Division a list of all leaks repaired on its pipeline facilities. Each such operator shall list all leaks identified on all pipeline facilities. Each such operator shall also include the number of unrepaired leaks remaining on the operator's systems by leak grade. Each such operator shall submit leak reports using the Commission's online reporting system, Form PS-95, by July 15 and January 15 of each calendar year, in accordance with the PS-95 Semi-Annual Leak Report Electronic Filing Requirements, set out in the Figure in this subsection. The report submitted on July 15 shall include information from the previous January 1 through the previous June 30. The report submitted on January 15 shall include information from the previous July 1 through the previous December 31. The report includes:

(1) leak location;

(2) facility type;

(3) leak classification;

(4) pipe size;

(5) pipe type;

(6) leak cause; and

(7) leak repair method.

PS-95 Semi-Annual Leak Report
Electronic Filing Requirements

The Railroad Commission of Texas (RRC or Commission) has implemented an online system for the filing of Pipeline Integrity reports. The web-based system is a part of the RRC Online system. This document describes Electronic Document Interchange (EDI) filing procedures for the PS-95 Leak Report that is a part of the Pipeline Integrity application.

EDI Filing Option:

a) Capability to file PS-95 Leak Reports via EDI.

b) The new system provides a delimited format allowing filers to easily file via EDI. Anyone using spreadsheet software to compile PS-95 data will be able to export the file to a right curly bracket (}) delimited format for EDI submission.

c) Elimination of the Commission's requirement to submit a test file. The Pipeline Integrity application will validate the format of each file submitted. A file not meeting the formatting requirements will be rejected. The filer will be required to correct the formatting error and resubmit the file. Since this check will be performed each time a file is submitted, the necessity to submit and receive a certification of formatting is redundant and therefore eliminated. However, the Commission will provide EDI filers with the capability to test a file prior to submitting to validate their EDI file format.

d) For specific records not meeting the filing requirements, the filer will receive error/approval feedback on the screen in the form of a message. A file may be resubmitted once all errors are corrected.

Security:

An organization (i.e., a Form P-5 operator) must file a Security Administrator Designation (SAD) Form with the Commission as a requirement for filing online and/or EDI. An account is created for the person designated on the SAD Form as the Security Administrator for the organization. This Security Administrator, in turn, can assign "Filing Rights" to employees of the organization authorizing them to file RRC forms online.

Organizations who have existing SAD forms do not need to re-file. The existing Security Administrators will be able to assign Pipeline Integrity "Filings Rights" to the users within the RRC Online Application.

EDI file and format requirements:

1) Permission to file electronically must be obtained from the Commission via a SAD (Security Administrator Designation) Form. Contact the P-5 department for more information. Information may also be found at http://www.rrc.state.tx.us/formpr/index.html
2) The file will have a delimited format. Only the following delimiter is allowed: a right curly bracket **}** (rcb)**.**.
3) Numeric columns must not contain any commas—e.g., use 1000000 for one million, not 1,000,000. Nor should columns contain currency formatting like "$" or "USD".
4) Data entry is case sensitive.

Record Layouts:

Identifying Record

Each file submitted to the RRC for EDI processing must have an Identifying Record as the first record in the file. The processing of this record includes the validation that the User ID is authorized to file electronically. An operator may obtain authorization by submitting the Security Administrator Designation form (SAD) to the Commission's P-5 department.

Order	Req-uired	Max Length (in char-acters)	Data Item	Data Type	Description
1	Y	1	Record Type	Integer	Type of record for this identifying record must be 1
2	Y	4	Report Type	Alpha-numeric	Must be PS95.
3	Y	10	User ID	Alpha-numeric	User ID assigned by the RRC to the filer. User ID must match User ID of person logged in
4	Y	32	User Name	Alpha- numeric	Name of the User submitting the file
5	Y	32	User E-mail Address	Character	Email address for the User. Will be used to contact the User and should be valid.
6	Y	6	Operator Number	Integer	Operator Number is the 6 digit number assigned to P-5 Operators by the RRC.
7	Y	4	Report Year	Integer	Reporting year currently being accepted. Format is YYYY.
8	Y	1	Report Period	Integer	1 = 1st half of year, January – June 2 = 2nd half of year, July – December
9	Y	4	Record Count	Integer	Number of records in this filing.

PS-95 Unrepaired Leak Summary Record

Data included in this record type will replace any previously submitted data.

Order	Req.	Max Length	Data Item	Data Type	Description
1	Y	1	Record Type	Integer	Type of Record for Detail Record must be 2.
2	Y	6	Total Grade 1 Unrepaired Leaks for filing period	Integer	Number of unrepaired leaks considered an existing or probable hazard to person or property requiring prompt action. See Leak Classification Lookup Table on page 8 for complete Grade 1 definition.
3	Y	6	Total Grade 2 Unrepaired Leaks for filing period	Integer	Number of unrepaired leaks considered non-hazardous but a probable future hazard. See Leak Classification Lookup Table on page 8 for complete Grade 2 definition.
4	Y	6	Total Grade 3 Unrepaired Leaks for filing period	Integer	Number of unrepaired leaks considered non-hazardous and expected to remain non-hazardous. See Leak Classification Lookup Table on page 8 for complete Grade 3 definition.

PS-95 Leak Report Detail

* Denotes Required in some circumstances. See Description for specifics.

Order	Req.	Max Length	Data Item	Data Type	Description
1	Y	1	Record Type	Integer	Type of Record for Detail Record must be 3
2	Y	6	Pipeline System ID	Integer	System ID is the 6-digit number assigned by the RRC.
3	Y	20	Operator's Leak ID	Alpha- numeric	An Operator-generated number for the leak incident. Must be unique to the incident during that filing period for the Operator. All characters are allowed.
4	Y	8	Date Leak Reported	Integer	Date that the leak was reported, not always the date it occurred including two digit month and day, and 4-digit year. Must be in format (YYYYMMDD). If the specific day is not known, use the first of the month. Date must be prior to or within the current filing period. It may not be a future date.
5	Y	40	Street Address 1	Alpha-numeric	Address where the leak occurred. Address may read "2500 Block of Main Street" if the exact address is not known. **Must be at least 3 characters in length**
6	N	40	Street Address 2	Alpha-numeric	Second Address Line where the leak occurred.
7	Y	40	City	Alpha	City (or nearest city) where the leak occurred. **Must be at least 3 characters in length.**
8	N	5	Zip Code	Integer	5-digit zip code where the leak occurred. If entered, should correspond with the City indicated above.

Order	Req.	Max Length	Data Item	Data Type	Description
9	Y	3	County	Integer	County where the leak occurred. Select an FIPS County Code from County Code Lookup Table beginning on page 13.
10	Y	1	Leak Located	Integer	Valid values are 1 (Above Ground Piping) and 2 (Below Ground Piping). The soil/air interface is considered above ground.
11	Y	2	Leak Located On	Integer	Further pinpoints the location of the leak along the pipeline. Select a value from Located On Lookup Table on page 8.
12	N	7	Material Type	String	Compression Coupling Material Type - Either 'Steel' or 'Plastic'. Required if Leak Located On value equals 12.
13	N	8	Compression Coupling Date	Integer	Date compression coupling installed. Required if Leak Located On value equals 12. Must be in format (YYYYMMDD).
14	Y	1	Facility Type	Integer	Indicates the type of facility affected. Select a code from Facility Type Lookup Table on page 8.
15	Y	4	Pipe Size	Decimal	Decimal representation of IPS pipe size from ½ inch to 12 inches. For example, ½ inch would be .5 or 0.5 or 0.50, 3 ½ inch would be 3.5 or 3.50 and 11 inch would be 11 or 11.0 or 11.00.
16	Y	2	Pipe Type	Integer	Material type where the leak is located. Select a code from Pipe Type Lookup Table on page 9.
17	*	3	Pipe Manufacturer	Alpha- numeric	**If the Pipe Type Code is 8, 9 or 11**, provide a Manufacturer. Select a code from Pipe Manufacturer Lookup Table on page 9.
18	*	3	Pipe ASTM Material Code	Alpha- numeric	**If the Pipe Type is 8, 9 or 11**, provide the ASTM Material Code. See ASTM Code Lookup Table on page 10.
19	Y	1	Leak Classification	Integer	The leak classification is based on the operating and maintenance procedures. Select a code from Leak Classification Lookup Table on page 8.

Order	Req.	Max Length	Data Item	Data Type	Description
20	*	2	Type of Leaking Joint	Integer	The type of joint that leaked. **Required if Located On code is 5 (Joint).** Select a code from Joint Type Lookup Table on page 10.
21	*	2	Type of Leaking Fitting	Integer	The type of fitting that leaked. **Required if Located On code is 4 (Fitting).** Select a code from Fitting Type Lookup Table on page 11.
22	*	20	Coupling Model	Alpha	The model of the coupling that failed. **Required if Located On code is 12.**
23	*	20	Coupling Manufacturer	Alpha	The manufacturer of the coupling that failed. **Required if Located On code is 12.**
24	Y	2	Leak Cause	Integer	The root cause of the failure. Select a code from Leak Cause Lookup Table on page 12.
25	*	250	Other Leak Cause	Alpha- numeric	Further defines an Other Leak Cause. **Required if Other Leak Cause code 81** was entered for Leak Cause. **Must be at least 3 characters in length.**
26	Y	2	Leak Repair Method	Integer	Type of repair that was made. Select a code from Leak Repair Method Lookup Table on page 13.
27	Y	8	Repair Date	Integer	Date the repair was made. The date must be during the reporting period, cannot be a future date, cannot be before the date the leak was reported, and must be formatted YYYYMMDD.

Lookup Tables

Leak Classification Lookup Table

LEAK CLASSIFICATION CODE	DESCRIPTION
1	Grade 1 – A Grade 1 leak is an existing or probable hazard to persons or property and requires the operator to take action immediately to eliminate the hazard and make repairs.
2	Grade 2 – A Grade 2 leak is non-hazardous at the time of detection, but requires the operator to schedule repair based on probable future hazard. It can be scheduled for repair on a normal routine basis with periodic re-inspection as necessary.
3	Grade 3 – A Grade 3 leak is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

Located On Lookup Table

LOCATED ON CODE	DESCRIPTION
1	Valve
2	Body of Pipe
3	Stopcock
4	Fitting
5	Joint
6	Gauge Line
7	Riser
8	Regulator
9	Meter
10	Drip
11	Tap
12	Compression Coupling

Facility Type Lookup

FACILITY TYPE CODE	DESCRIPTION
1	Main
2	Service
3	Transmission

Pipe Type Lookup Table

PIPE TYPE CODE	DESCRIPTION
1	Bare Steel
2	Coated Steel
3	Ductile Iron
4	Cast Iron
5	Galvanized
6	Copper
7	Brass
8	High Density Polyethylene
9	Medium Density Polyethylene
10	Aldyl Polyethylene
11	Poly-Vinyl-Chloride

Pipe Manufacturer Lookup Table (High Density PE, Medium Density PE, or PVC)

CODE	MANUFACTURER
PP1	PolyPipe
PP2	PolyPipe, Inc.
PP3	CSR PolyPipe
RK1	Rinker
PF1	Performance Pipe
PX1	Plexco
DC1	Driscopipe
QU1	Quail
UP1	Uponorr
NP1	Nipak
OTH	Other Manufacturer, not listed, or unknown

ASTM Code Lookup Table (HDPE, MDPE, or PVC) (High Density PE, Medium Density PE, or PVC)

MATERIAL CODE	DESCRIPTION
PA1	Polyamide PA 32312
PB1	Polybutylene PB 2110
PE1	Polyethylene PE 2306
PE2	Polyethylene PE 2406
PE3	Polyethylene PE 3406
PE4	Polyethylene PE 3408
PV1	Polyvinyl Chloride PVC 1120
PV2	Polyvinyl Chloride PVC 1220
PV3	Polyvinyl Chloride PVC 2110
PV4	Polyvinyl Chloride PVC 2116
ABS	Acrylonitrile Butadiene Styrene ABS 1210
CA1	Cellulose Acetate Butyrate CAB MH08
CA2	Cellulose Acetate Butyrate CAB S004
RTR	Reinforced Epoxy Resin RTRP
OTH	Other Material Designation

Joint Type Lookup Table

JOINT TYPE CODE	DESCRIPTION
1	Factory Butt Weld (Steel)
2	Factory Fillet Weld (Steel)
3	Field Butt Weld (Steel)
4	Field Fillet Weld (Steel)
5	Threaded
6	Mechanical Joint
7	Bell & Spigot
8	Flange
9	Butt Fusion (Plastic)
10	Socket Fusion (Plastic)
11	Saddle Fusion (Plastic)
12	Electrofusion (Plastic)
13	Sidewall Fusion (Plastic)
14	Not Applicable
15	Other

Fitting Type Lookup Table

FITTING TYPE CODE	DESCRIPTION
1	Mechanical Service Tee
2	Heat Fusion Service Tee
3	Electrofusion Service Tee
4	Welded Service Tee
5	Saddle Fitting
6	Service Tee Cap
7	Anodeless Meter Riser
8	Threadolets/Weldolets/Sockolets
9	Plugs/Caps
10	Elbow
11	Nipple
12	Tee
13	Diaphragm
14	Other Meter Riser
17	Transition Fitting
18	Split Sleeve
19	Leak Clamp
20	Bell Joint Clamp
21	Meter Swivel
22	Union
23	Insulator
24	Other

Leak Cause Lookup Table

LEAK CAUSE GROUP	LEAK CAUSE CODE	LEAK CAUSE DESCRIPTION
Corrosion Group		
	11	Corrosion
Excavation Group		
	21	Operator Personnel/Contractors Excavating
	22	Other Third Party Excavators
	23	Locator
	24	Vehicle (Auto/Truck/etc.)
Natural Forces Group		
	31	Lightning
	32	Washout
	33	Ground Movement
	34	Ice
	35	Static Electricity
Other Outside Forces Group		
	41	Vandalism
	42	Fire/Explosion First
	43	Excessive Strain
Materials & Welds Group		
	51	Dent
	52	Gouge
	53	Factory Defect
	54	Wrinkle Bend
	55	Weld (Steel)
	56	Fusion Defect (Plastic)
Equipment Group		
	61	Equipment Malfunction
	62	Gasket/O-Ring
	63	Packing
Operations Group		
	71	Inadequate/Failure to Follow Procedures
	72	Stripped Threads
	73	Backfill
Other Group		
	81	Other
	82	Not Excavated

Leak Repair Method Lookup Table

REPAIR METHOD CODE	DESCRIPTION
1	Clamp Installed
2	Split Sleeve
3	Encapsulation
4	Component Replaced
5	Abandoned (Not Replaced)
6	Pipe Replaced
7	Greasing
8	Doped/Caulked
9	Tighten
10	Sealing Bell & Spigot Joint
11	Insertion

County Code Lookup Table

FIPS CODE	COUNTY NAME
001	ANDERSON
003	ANDREWS
005	ANGELINA
007	ARANSAS
009	ARCHER
011	ARMSTRONG
013	ATASCOSA
015	AUSTIN
017	BAILEY
019	BANDERA
021	BASTROP
023	BAYLOR
025	BEE
027	BELL
029	BEXAR

FIPS CODE	COUNTY NAME
031	BLANCO
033	BORDEN
035	BOSQUE
037	BOWIE
039	BRAZORIA
041	BRAZOS
043	BREWSTER
045	BRISCOE
047	BROOKS
049	BROWN
051	BURLESON
053	BURNET
055	CALDWELL
057	CALHOUN
059	CALLAHAN
061	CAMERON
063	CAMP
065	CARSON
067	CASS
069	CASTRO
071	CHAMBERS
073	CHEROKEE
075	CHILDRESS
077	CLAY
079	COCHRAN
081	COKE
083	COLEMAN
085	COLLIN
087	COLLINGSWORTH
089	COLORADO

FIPS CODE	COUNTY NAME
091	COMAL
093	COMANCHE
095	CONCHO
097	COOKE
099	CORYELL
101	COTTLE
103	CRANE
105	CROCKETT
107	CROSBY
109	CULBERSON
111	DALLAM
113	DALLAS
115	DAWSON
117	DEAF SMITH
119	DELTA
121	DENTON
123	DEWITT
125	DICKENS
127	DIMMIT
129	DONLEY
131	DUVAL
133	EASTLAND
135	ECTOR
137	EDWARDS
141	EL PASO
139	ELLIS
143	ERATH
145	FALLS
147	FANNIN
149	FAYETTE

FIPS CODE	COUNTY NAME
151	FISHER
153	FLOYD
155	FOARD
157	FORT BEND
159	FRANKLIN
161	FREESTONE
163	FRIO
165	GAINES
167	GALVESTON
169	GARZA
171	GILLESPIE
173	GLASSCOCK
175	GOLIAD
177	GONZALES
179	GRAY
181	GRAYSON
183	GREGG
185	GRIMES
187	GUADALUPE
189	HALE
191	HALL
193	HAMILTON
195	HANSFORD
197	HARDEMAN
199	HARDIN
201	HARRIS
203	HARRISON
205	HARTLEY
207	HASKELL
209	HAYS

FIPS CODE	COUNTY NAME
211	HEMPHILL
213	HENDERSON
215	HIDALGO
217	HILL
219	HOCKLEY
221	HOOD
223	HOPKINS
225	HOUSTON
227	HOWARD
229	HUDSPETH
231	HUNT
233	HUTCHINSON
235	IRION
237	JACK
239	JACKSON
241	JASPER
243	JEFF DAVIS
245	JEFFERSON
247	JIM HOGG
249	JIM WELLS
251	JOHNSON
253	JONES
255	KARNES
257	KAUFMAN
259	KENDALL
261	KENEDY
263	KENT
265	KERR
267	KIMBLE
269	KING

FIPS CODE	COUNTY NAME
271	KINNEY
273	KLEBERG
275	KNOX
283	LA SALLE
277	LAMAR
279	LAMB
281	LAMPASAS
285	LAVACA
287	LEE
289	LEON
291	LIBERTY
293	LIMESTONE
295	LIPSCOMB
297	LIVE OAK
299	LLANO
301	LOVING
303	LUBBOCK
305	LYNN
313	MADISON
315	MARION
317	MARTIN
319	MASON
321	MATAGORDA
323	MAVERICK
307	MCCULLOCH
309	MCLENNAN
311	MCMULLEN
325	MEDINA
327	MENARD
329	MIDLAND

FIPS CODE	COUNTY NAME
331	MILAM
333	MILLS
335	MITCHELL
337	MONTAGUE
339	MONTGOMERY
341	MOORE
343	MORRIS
345	MOTLEY
347	NACOGDOCHES
349	NAVARRO
351	NEWTON
353	NOLAN
355	NUECES
357	OCHILTREE
359	OLDHAM
361	ORANGE
363	PALO PINTO
365	PANOLA
367	PARKER
369	PARMER
371	PECOS
373	POLK
375	POTTER
377	PRESIDIO
379	RAINS
381	RANDALL
383	REAGAN
385	REAL
387	RED RIVER
389	REEVES

FIPS CODE	COUNTY NAME
391	REFUGIO
393	ROBERTS
395	ROBERTSON
397	ROCKWALL
399	RUNNELS
401	RUSK
403	SABINE
405	SAN AUGUSTINE
407	SAN JACINTO
409	SAN PATRICIO
411	SAN SABA
413	SCHLEICHER
415	SCURRY
417	SHACKELFORD
419	SHELBY
421	SHERMAN
423	SMITH
425	SOMERVELL
427	STARR
429	STEPHENS
431	STERLING
433	STONEWALL
435	SUTTON
437	SWISHER
439	TARRANT
441	TAYLOR
443	TERRELL
445	TERRY
447	THROCKMORTON
449	TITUS

FIPS CODE	COUNTY NAME
451	TOM GREEN
453	TRAVIS
455	TRINITY
457	TYLER
459	UPSHUR
461	UPTON
463	UVALDE
465	VAL VERDE
467	VAN ZANDT
469	VICTORIA
471	WALKER
473	WALLER
475	WARD
477	WASHINGTON
479	WEBB
481	WHARTON
483	WHEELER
485	WICHITA
487	WILBARGER
489	WILLACY
491	WILLIAMSON
493	WILSON
495	WINKLER
497	WISE
499	WOOD
501	YOAKUM
503	YOUNG
505	ZAPATA
507	ZAVALA

The provisions of this §8.210 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective May 15, 2005, 30 TexReg 2849; amended to be effective February 4, 2009, 34 TexReg 582.

§8.215. Odorization of Gas.

(a) Odorization of gas.

(1) Each gas company shall continuously odorize gas by the use of a malodorant agent as set forth in this section unless the gas contains a natural malodor or is odorized prior to delivery by a supplier.

(2) Unless required by 49 CFR Part 192.625(B) or by this section, odorization is not required for:

(A) gas in underground or other storage;

(B) gas used or sold primarily for use in natural gasoline extraction plants, recycling plants, chemical plants, carbon black plants, industrial plants, or irrigation pumps; or

(C) gas used in lease and field operation or development or in repressuring wells.

(3) Gas shall be odorized by the user if:

(A) the gas is delivered for use primarily in one of the activities or facilities listed in paragraph (2) of this subsection and is also used in one of those activities for space heating, refrigeration, water heating, cooking, and other domestic uses; or

(B) the gas is used for furnishing heat or air conditioning for office or living quarters.

(4) In the case of lease users, the supplier shall ensure that the gas will be odorized before being used by the consumer.

(b) Odorization equipment. Gas companies shall use commercially available odorization equipment in any installation made on or after February 4, 2009. Shop-made or other odorization equipment previously approved by the Commission and in use as of February 4, 2009, may continue to be used in its current service, but may not be re-installed in a different location. Each operator shall be required to maintain a list of odorization equipment used in its particular operations, including the location of the odorization equipment, the brand name, model number, and the date last serviced. The list shall be available for review during safety evaluations by the Division.

(c) Malodorants. Gas companies shall use commercially available malodorants which shall meet the following criteria.

(1) The malodorant when blended with gas in the amount specified for adequate odorization of the gas shall not be deleterious to humans or to the materials present in a gas system and shall not be soluble in water to a greater extent than 2 1/2 parts by weight of malodorant to 100 parts by weight of water.

(2) The products of combustion from the malodorant shall be nontoxic to humans breathing air containing the products of combustion and the products of combustion shall not be corrosive or harmful to the materials to which such products of combustion would ordinarily come in contact.

(3) The malodorant agent to be introduced in the gas, or the natural malodor of the gas, or the combination of the malodorant and the natural malodor of the gas shall have a distinctive malodor so that when gas is present in air at a concentration of one-fifth of the lower explosive limit, the malodor is readily detectable by an individual with a normal sense of smell.

(4) The level of natural malodor or the injection rate of approved malodorant shall be sufficient to achieve the requirement of paragraph (3) of this subsection.

(d) Malodorant tests and reports.

(1) Malodorant injection report. Each gas company shall record as frequently as necessary to maintain adequate odorization but not less than once each quarter the following malodorant information for all odorization equipment, except farm tap odorizers. The required information shall be recorded and retained in the company's files:

(A) odorizer location;

(B) brand name and model of odorizer;

(C) name of malodorant, concentrate, or dilute;

(D) quantity of malodorant at beginning of month/quarter;

(E) amount added during month/quarter;

(F) quantity at end of month/quarter;

(G) MMcf of gas odorized during month/quarter; and

(H) injection rate per MMcf.

(2) Each natural gas operator shall check, test, and service farm tap odorizers at intervals not exceeding 15 months, but at least once each calendar year. Each gas company shall maintain records to reflect the date of service and maintenance on file for at least two years.

(e) Malodorant concentration tests and reports.

(1) Each gas company shall conduct the following concentration tests on the gas supplied through its facilities and required to be odorized. Test points shall be distant from odorizing equipment, so as to be representative of the odorized gas in the system. Tests shall be performed at intervals not exceeding 15 months, but at least once each calendar year or at such other times as the Division may reasonably require. The results of these tests shall be recorded and retained in each company's files for at least two years. Malodorant concentration test results shall include the following:

(A) odorizer name and location;

(B) malodorant concentration meter make, model, and serial number;

(C) date test performed, test time, odorizer tested, and distance from odorizer;

(D) test results indicating percent gas in air when malodor is readily detectable; and

(E) signature of person performing the test.

(2) Farm tap odorizers shall be exempt from the odorization testing requirements of paragraph (1) of this subsection.

(3) Gas companies that obtain gas into which malodorant previously has been injected or gas which is considered to have a natural malodor and therefore do not odorize the gas themselves shall be required to conduct quarterly malodorant concentration tests and retain records for a period of two years.

The provisions of this §8.215 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective February 4, 2009, 34 TexReg 582.

§8.220. Master Metered Systems.

(a) Compliance with minimum standards required. Master meter operators shall comply with the minimum safety standards in 49 CFR Part 192.

(b) Leakage survey. Each master meter operator shall conduct a leakage survey on the system every two years, using leak detection equipment.

(c) Overpressure equipment. Natural gas suppliers shall be responsible for installation and inspection of overpressure equipment at those master meter locations where 10 or more consumers are served low pressure gas.

The provisions of this §8.220 adopted to be effective November 24, 2004, 29 TexReg 10733.

§8.225. Plastic Pipe Requirements.

(a) Plastic pipe installation and/or removal report.

(1) Each operator shall have reported to the Commission on March 15, 2003, and March 15, 2004, the amount in miles of plastic pipe installed and/or removed during the preceding calendar year on Form PS-82, Annual Report of Plastic Installation and/or Removal. The mileage shall have been identified by:

(A) system;

(B) nominal pipe size;

(C) material designation code;

(D) pipe category; and

(E) pipe manufacturer.

(2) For all new installations of plastic pipe, each operator shall record and maintain for the life of the pipeline the following information for each pipeline segment:

(A) all specification information printed on the pipe;

(B) the total length;

(C) a citation to the applicable joining procedures used for the pipe and the fittings; and

(D) the location of the installation to distinguish the end points. A pipeline segment is defined as continuous piping where the pipe specification required by ASTM D2513 or ASTM D2517 does not change.

(b) Plastic pipe inventory report. Beginning March 15, 2005, and annually thereafter, each operator shall report to the Division the amount of plastic pipe in natural gas service as of December 31 of the previous year. The amount of plastic pipe shall be determined by a review of the records of the operator and shall be reported on Form PS-81, Plastic Pipe Inventory. The report shall include the following:

(1) system;

(2) miles of pipe;

(3) calendar year of installation;

(4) nominal pipe size;

(5) material designation code;

(6) pipe category; and

(7) pipe manufacturer.

(c) Electronic format required. Operators of systems with more than 1,000 customers shall file the reports required by this section electronically in a format specified by the Commission.

(d) Report forms; signature required. Operators shall complete all forms required to be filed in accord with this section, including signatures of company officials. The Commission may consider the failure of an operator to complete all forms as required to be a violation under Texas Utilities Code, Chapter 121, and may seek penalties as permitted by that chapter.

The provisions of this §8.225 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective February 4, 2009, 34 TexReg 582.

§8.230. School Piping Testing.

(a) Purpose. The purpose of this section is to implement the requirements of Texas Utilities Code, §§121.5005 - 121.507, relating to the testing of natural gas piping systems in school facilities.

(b) Procedures. Natural gas suppliers shall develop procedures for:

(1) receiving written notice from a person responsible for a school facility specifying the date and result of each test as provided by subsection (c) of this section.

(2) terminating natural gas service to a school facility in the event that:

(A) the natural gas supplier receives notification of a hazardous natural gas leak in the school facility piping system pursuant to this rule; or

(B) the natural gas supplier does not receive written notification specifying the date that testing has been completed on a school facility as provided by subsection (c) of this section, and the results of such testing.

(3) A natural gas supplier may rely on a written notification complying with this rule as proof that a school facility is in compliance with Texas Utilities Code, §§121.5005 - 121.507, and this rule.

(4) A natural gas supplier shall have no duty to inspect a school facility for compliance with Texas Utilities Code, §§121.5005 - 121.507.

(c) Testing.

(1) A natural gas piping pressure test performed under a municipal code in compliance with paragraphs (4) and (5) of this subsection shall satisfy the testing requirements.

(2) A pressure test to determine if the natural gas piping in each school facility will hold at least normal operating pressure shall be performed as follows:

(A) School facility pipe testing includes all gas piping from the outlet of the purchase meter to each inlet valve of each appliance.

(B) For systems on which the normal operating pressure is less than 0.5 psig, the test pressure shall be 5 psig and the time interval shall be 30 minutes.

(C) For systems on which the normal operating pressure is 0.5 psig or more, the test pressure shall be 1.5 times the normal operating pressure or 5 psig, whichever is greater, and the time interval shall be 30 minutes.

(D) A pressure test using normal operating pressure shall be utilized only on systems operating at 5 psig or greater, and the time interval shall be one hour.

(3) The testing shall be conducted by:

(A) a licensed plumber;

(B) a qualified employee or agent of the school who is regularly employed as or acting as a maintenance person or maintenance engineer; or

(C) a person exempt from the plumbing license law as provided in Texas Civil Statutes, Article 6243-101, §3.

(4) The testing of public school facilities shall occur as follows:

(A) for school facilities tested prior to the beginning of the 1997-1998 school year, at least once every two years thereafter before the beginning of the school year;

(B) for school facilities not tested prior to the beginning of the 1997-1998 school year, as soon as practicable thereafter but prior to the beginning of the 1998-1999 school year and at least once every two years thereafter before the beginning of the school year;

(C) for school facilities operated on a year-round calendar and tested prior to July 1, 1997, at least once every two years thereafter; and

(D) for school facilities operated on a year-round calendar and not tested prior to July 1, 1997, once prior to July 1, 1998, and at least once every two years thereafter.

(5) The testing of charter and private school facilities shall occur at least once every two years and shall be performed before the beginning of the school year, except for school facilities operated on a year-round calendar, which shall be tested not later than July 1 of the year in which the test is performed. The initial test of charter and private school facilities shall occur prior to the beginning of the 2003-2004 school year or by August 31, 2003, whichever is earlier.

(6) The firm or individual conducting the test shall immediately report any hazardous natural gas leak as follows:

(A) in a public school facility, to the board of trustees of the school district and the natural gas supplier; and

(B) in a charter or private school facility, to the person responsible for such school facility and the natural gas supplier.

(7) The school pipe testing shall be recorded on Railroad Commission Form PS-86.

(d) Records. Natural gas suppliers shall maintain for at least two years a listing of the school facilities to which it sells and delivers natural gas as well as copies of the written notification regarding testing, Form PS-86, and hazardous leaks received pursuant to Texas Utilities Code, §§121.5005 - 121.507, and this rule.

The provisions of this §8.230 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective February 4, 2009, 34 TexReg 582.

§8.235. Natural Gas Pipelines Public Education and Liaison.

(a) Liaison activities required. Each operator of a natural gas pipeline or natural gas pipeline facilities or the operator's designated representative shall communicate and conduct liaison activities at intervals not exceeding 15 months, but at least once each calendar year with fire, police, and other appropriate public emergency response officials. The liaison activities are those required by 49 CFR Part 192.615(c)(1) - (4). These liaison activities shall be conducted in person, except as provided by this section.

(b) Meetings in person. The operator or the operator's representative may conduct the required community liaison activities as provided by subsection (c) of this section only if the operator or the operator's representative has made an effort to conduct a community liaison meeting in person with the officials by one of the following methods:

(1) mailing a written request for a meeting in person to the appropriate officials by certified mail, return receipt requested;

(2) sending a request for a meeting in person to the appropriate officials by facsimile transmission; or

(3) making one or more telephone calls or e-mail message transmissions to the appropriate officials to request a meeting in person.

(4) If a scheduled meeting does not take place, the operator or operator's representative shall make an effort to re-schedule the community liaison meeting in person with the officials using one of the methods in paragraphs (1) - (3) of this subsection before proceeding to arrange a conference call pursuant to subsection (c) of this section.

(c) Alternative methods. If the operator or operator's representative cannot arrange a meeting in person after complying with subsection (b) of this section, the operator or the operator's representative shall conduct community liaison activities by one of the following methods:

(1) holding a telephone conference with the appropriate officials; or

(2) delivering the community liaison information requested to be conveyed by certified mail, return receipt requested.

(d) Proximity to public school. Each owner or operator of a natural gas pipeline or natural gas pipeline facility any part of which is located within 1,000 feet of a public school building or public school recreational area shall notify the Commission by filing with the Division, no later than January 15 of every even-numbered year, the following information:

(1) the name of the school;

(2) the street address of the school; and

(3) the identification (system name) of the pipeline.

(e) Records. The operator shall maintain records documenting compliance with the liaison activities required by this section. Records of attendance and acknowledgment of receipt by the emergency response officials shall be retained for five years from the date of the event that is commemorated by the record. Records of certified mail and/or telephone transmissions undertaken in compliance with subsections (b) and (c) of this section satisfy the record-keeping requirements of this subsection.

The provisions of this §8.235 adopted to be effective July 28, 2003, 28 TexReg 5864; amended to be effective November 24, 2004, 29 TexReg 10733; amended to be effective February 4, 2009, 34 TexReg 582; amended to be effective August 30, 2010, 35 TexReg 7743.

§8.240. Discontinuance of Service.

(a) Within 30 calendar days following notification from a customer to discontinue natural gas service at that customer's service location, each operator shall take one of the three steps specified in 49 CFR §192.727(d) unless the operator receives notice within such 30 calendar day time period that service is to be continued at that service location to another customer or an owner or manager of the service location.

(b) Upon receipt of a notification from a customer to discontinue gas service, the operator shall inform the customer that the gas service may remain on at the service location for up to 30 calendar days following the customer's requested date for discontinuance.

(c) Each operator shall have a written procedure in its operations and maintenance manual for service discontinuance that includes the requirements of this rule.

The provisions of this §8.240 adopted to be effective September 8, 2003, 28 TexReg 7685.

SUBCHAPTER D. REQUIREMENTS FOR HAZARDOUS LIQUIDS AND CARBON DIOXIDE PIPELINES ONLY

§8.301. Required Records and Reporting.

(a) Accident reports. In the event of any failure or accident involving an intrastate pipeline facility from which any hazardous liquid or carbon dioxide is released, if the failure or accident is required to be reported by 49 CFR Part 195, the operator shall report to the Commission as follows.

(1) Incidents involving crude oil. In the event of an accident involving crude oil, the operator shall:

(A) notify the Division, which shall notify the Commission's appropriate Oil and Gas district office, by telephone to the Commission's emergency line at (512) 463-6788 at the earliest practicable moment following discovery of the incident (within two hours) and include the following information:

(i) company/operator name;

(ii) location of leak or incident;

(iii) time and date of accident/incident;

(iv) fatalities and/or personal injuries;

(v) phone number of operator;

(vi) telephone number of operator;

(vii) telephone number of the operator's on-site person;

(viii) other significant facts relevant to the accident or incident. Ignition, explosion, rerouting of traffic, evacuation of any building, and media interest are included as significant facts.

(B) within 30 days of discovery of the incident, submit a completed Form H-8 to the Oil and Gas Division of the Commission. In situations specified in the 49 CFR Part 195, the operator shall also file a copy of the required Department of Transportation form with the Division. For reports submitted electronically to the Department of Transportation, the operator shall forward a copy of the report and confirmation to the Division or electronically to safety@rrc.state.tx.us. If an operator does not submit reports electronically to the Department of Transportation, the operator shall send the report to the Division on an original signed report form.

(2) Hazardous liquids, other than crude oil, and carbon dioxide. For incidents involving hazardous liquids, other than crude oil, and carbon dioxide, the operator shall:

(A) notify the Division of such incident by telephone to the Commission's emergency line at (512) 463-6788 at the earliest practicable moment following discovery (within two hours) and include the information listed in paragraph (1)(A)(i) - (viii) of this subsection; and

(B) within 30 days of discovery of the incident, file with the Division a written report using the appropriate Department of Transportation form (as required by 49 CFR Part 195) or a facsimile. For reports submitted electronically to the Department of Transportation, the operator shall forward a copy of the report and confirmation to the Division or electronically to safety@rrc.state.tx.us. If an operator does not submit reports electronically to the Department of Transportation, the operator shall send the report to the Division on an original signed report form.

(b) Annual report. Each operator shall file with the Commission an annual report for its intrastate systems located in Texas in the same manner as required by 49 CFR Part 195. The report shall be filed with the Commission on forms supplied by the Department of Transportation on or before June 15 of a year for the preceding calendar year reported. For reports submitted electronically to the Department of Transportation, the operator may forward a copy of the report and confirmation to the Division or electronically to safety@rrc.state.tx.us. For reports not submitted electronically to the Department of Transportation, the operator shall send to the Division an original signed report form.

(c) Safety-related condition reports. Each operator shall submit to the Division in writing a safety-related condition report for any condition specified in 49 CFR 195.

(d) Facility response plans. Simultaneously with filing either an initial or a revised facility response plan with the United States Department of Transportation, each operator shall submit to the Division a copy of the initial or revised facility response plan prepared under the Oil Pollution Act of 1990, for all or any part of a hazardous liquid pipeline facility located landward of the coast.

The provisions of this §8.301 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective February 4, 2009, 34 TexReg 582.

§8.305. Corrosion Control Requirements. Operators shall comply or ensure compliance with the following requirements for the installation and construction of new pipeline metallic systems, the relocation or replacement of existing facilities, and the operation and maintenance of steel pipelines.

(1) Coatings. All coated pipe used for the transport of hazardous liquids or carbon dioxide shall be electrically inspected prior to placement using coating deficiency (holiday) detectors to check for any faults not observable by visual examination. The holiday detector shall be operated in accordance with manufacturer's instructions and at a voltage level appropriate for the electrical characteristics of the pipeline system being tested.

(2) Installation. Joints, fittings, and tie-ins shall be coated with materials compatible with the coatings on the pipe.

(3) Cathodic protection test stations. Electrical measurements shall include but are not limited to pipe casing installations and all foreign metallic cathodically protected structures. Readings taken at test stations (electrode locations) over or near one or more anodes shall not, by themselves, be considered representative.

(A) All test lead wire attachments and bared test lead wires shall be coated with an electrically insulating material. Where the pipe is coated, the insulation of the test lead wire material shall be compatible with the pipe coating and wire insulation.

(B) Cathodic protection systems shall meet or exceed the minimum criteria set forth in Criteria For Cathodic Protection of the most current edition of the National Association of Corrosion Engineers (NACE) Standard RP-01-69.

(4) Monitoring and inspection. Each operator shall utilize right-of-way inspections to determine areas where interfering currents are suspected. In the course of these inspections, personnel shall be alert for electrical or physical conditions which could indicate interference from a neighboring source. Whenever suspected areas are identified, the operator shall conduct appropriate electrical tests within six months to determine the extent of interference and take appropriate action.

(5) Remedial action. Each operator shall take prompt remedial action to correct any deficiencies observed during monitoring.

The provisions of this §8.305 adopted to be effective November 24, 2004, 29 TexReg 10733; amended to be effective February 4, 2009, 34 TexReg 582.

§8.310. Hazardous Liquids and Carbon Dioxide Pipelines Public Education and Liaison.

(a) Liaison activities required. Each operator of a hazardous liquid or carbon dioxide pipeline or pipeline facilities or the operator's designated representative shall communicate and conduct liaison activities at intervals not exceeding 15 months, but at least once each calendar year with fire, police, and other appropriate public emergency response officials. The liaison activities are those required by 49 CFR Part 195.402(c)(12). These liaison activities shall be conducted in person, except as provided by this section.

(b) Meetings in person. The operator or the operator's representative may conduct required community liaison activities as provided by subsection (c) of this section only if the operator or the operator's representative has completed one of the following efforts to conduct a community liaison meeting in person with the officials:

(1) mailing a written request for a meeting in person to the appropriate officials by certified mail, return receipt requested;

(2) sending a request for a meeting in person to the appropriate officials by facsimile transmission; or

(3) making one or more telephone calls or e-mail message transmissions to the appropriate officials to request a meeting in person.

(4) At any time the operator or operator's representative makes contact with the appropriate officials and schedules a meeting in person, no further attempts to make contact under this section are necessary. However, if a scheduled meeting does not take place, the operator or operator's representative shall make an effort to re-schedule the community liaison meeting in person with the officials using one of the methods in paragraphs (1) - (3) of this subsection before proceeding to arrange a conference call pursuant to subsection (c) of this section.

(c) Alternative methods. If the operator or operator's representative cannot arrange a meeting in person after complying with subsection (b) of this section, the operator or the operator's representative shall conduct community liaison activities by one of the following methods:

(1) holding a telephone conference with the appropriate officials; or

(2) delivering the community liaison information required to be conveyed by certified mail, return receipt requested.

(d) Records. The operator shall maintain records documenting compliance with the liaison activities required by this section. Records of attendance and acknowledgment of receipt by the emergency response officials shall be retained for five years from the date of the event that is commemorated by the record. Records of certified mail and/or telephone transmissions undertaken in compliance with subsections (b) and (c) of this section satisfy the record-keeping requirements of this subsection.

The provisions of this §8.310 adopted to be effective July 28, 2003, 28 TexReg 5864; amended to be effective February 4, 2009, 34 TexReg 582; amended to be effective August 30, 2010, 35 TexReg 7743.

§8.315. Hazardous Liquids and Carbon Dioxide Pipelines or Pipeline Facilities Located Within 1,000 Feet of a Public School Building or Facility.

(a) In addition to the requirements of §8.310 of this title (relating to Hazardous Liquids and Carbon Dioxide Pipelines Public Education and Liaison), each owner or operator of each intrastate hazardous liquids pipeline or pipeline facility and each intrastate carbon dioxide pipeline or pipeline facility shall comply with this section.

(b) This section applies to each owner or operator of a hazardous liquid or carbon dioxide pipeline or pipeline facility any part of which is located within 1,000 feet of a public school building containing classrooms, or within 1,000 feet of any other public school facility where students congregate.

(c) Each pipeline owner and operator to which this section applies shall, for each pipeline or pipeline facility any part of which is located within 1,000 feet of a public school building containing classrooms, or within 1,000 feet of any other public school facility where students congregate, file with the Division, no later than January 15 of every odd numbered year, the following information:

(1) the name of the school;

(2) the street address of the public school building or other public school facility; and

(3) the identification (system name) of the pipeline.

(d) Each pipeline owner and operator to which this section applies shall:

(1) upon written request from a school district, provide in writing the following parts of a pipeline emergency response plan that are relevant to the school:

(A) a description and map of the pipeline facilities that are within 1,000 feet of the school building or facility;

(B) a list of any product transported in the segment of the pipeline that is within 1,000 feet of the school facility;

(C) the designated emergency number for the pipeline facility operator;

(D) information on the state's excavation one-call system; and

(E) information on how to recognize, report, and respond to a product release; and

(2) mail a copy of the requested items by certified mail, return receipt requested, to the superintendent of the school district in which the school building or facility is located.

(e) A pipeline operator or the operator's representative shall appear at a regularly scheduled meeting of the school board to explain the items listed in subsection (c) of this section if requested by the school board or school district.

(f) Records. Each owner or operator shall maintain records documenting compliance with the requirements of this section. Records of attendance and acknowledgment of receipt by the school board or school district superintendent shall be retained for five years from the date of the event that is commemorated by the record. Records of certified mail transmissions undertaken in compliance with this section satisfy the record-keeping requirements of this subsection.

The provisions of this §8.315 adopted to be effective December 3, 2003, 28 TexReg 10749; amended to be effective February 4, 2009, 34 TexReg 582; amended to be effective August 30, 2010, 35 TexReg 7743.