CHRISTI CRADDICK, *CHAIRMAN*
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RAILROAD COMMISSION OF TEXAS
OFFICE OF GENERAL COUNSEL

MEMORANDUM

TO: Chairman Christi Craddick
Commissioner Wayne Christian
Commissioner Jim Wright

FROM: Haley Cochran, Assistant General Counsel
Office of General Counsel

THROUGH: Alexander C. Schoch, General Counsel

DATE: November 19, 2024

SUBJECT: Adoption of amendments to 16 TAC §3.70 and various rules in Chapter 8

Attached is Staff's recommendation to adopt amendments to 16 Texas Administrative Code §3.70, relating to Pipeline Permits Required, and various rules in 16 Texas Administrative Code Chapter 8. The Commission adopts the amendments to §3.70 to incorporate federal categories of pipelines and to clarify reporting requirements due to corresponding amendments adopted in Chapter 8. Amendments in §3.70 also add a "single-signature" Form T-4 process.

The amendments in Chapter 8 incorporate by reference recent federal rulemakings issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA), including PHMSA's rulemaking extending reporting requirements to all gas gathering operators and setting minimum safety requirements for certain gas gathering pipelines with large diameters and high operating pressures. Other updates and corresponding amendments are proposed in other sections of Chapter 8.

On August 15, 2024, the Commission approved the publication of the proposed amendments in the Texas Register for a public comment period, which ended on October 15, 2024. Staff recommends that the Commission adopt the amendments to §3.70 without changes to the proposed text published in the August 30, 2024, issue of the Texas Register (49 TexReg 6559), and adopt the amendments to Chapter 8 with changes to the proposed text published in the Register. The recommended changes are described in the attached adoption preamble.

cc: Danny Sorrells, Acting Executive Director and Director of the Oil and Gas Division
Kari French, Director, Oversight and Safety Division
Stephanie Weidman, Pipeline Safety Director, Oversight and Safety Division

The Railroad Commission of Texas (Commission) adopts amendments to §3.70, relating to Pipeline Permits Required, without changes to the proposed text published in the August 30, 2024, issue of the Texas Register (49 TexReg 6559). The Commission adopts the amendments in §3.70 to align with changes concurrently adopted in Chapter 8, relating to Pipeline Safety Regulations, which incorporate federal requirements. The amendments to §3.70 also remove dates from the rule that no longer apply and incorporate a procedure related to the Form T-4B.

The Commission received six comments, five of which were from associations (Permian Basin Petroleum Association (PBPA), Pipeline Safety Trust, Sierra Club Lone Star Chapter (Sierra Club), Texas Industry Project, and Texas Oil and Gas Association (TXOGA)). One company, Atmos Energy Corporation's Mid-Texas Division and West Texas Division (Atmos) also commented. The Commission appreciates these comments.

Generally, Atmos commented that it supports the changes to §3.70, as they effectively remove outdated language, properly update the language regarding gathering lines, and provide a straightforward process for filing Form T-4B.

The Commission appreciates the comments from Atmos.

Regarding §3.70(i)(1)(A), TXOGA and PBPA sought clarity that Group A fees only apply to transmission and gathering pipelines, as defined by the Pipeline and Hazardous Materials Safety Administration (PHMSA), and would not include production lines defined in §8.1(a)(1)(B) of this title, relating to General Applicability and Standards.

The Commission notes that production pipelines covered under §8.1(a)(1)(B) currently fall under Group A, as defined by §3.70(i)(1)(A), and will continue to fall under Group A after these amendments.

The Commission received one comment from Sierra Club regarding increasing mileage fees for Group B operators under §3.70(i)(3), as well as the permit processing fee for all permitted pipelines under §3.70(j). Sierra Club suggested increasing the fee for Group B pipelines from $10 per mile to $15 per mile, and the permit processing fee from $500 to $1,000.

The Commission appreciates the comments from Sierra Club but acknowledges that the suggested fee increases are outside the scope of these amendments. The Commission did not propose changing Group B per mile fees, nor permit processing fees, and would need to propose these fee changes and allow public comments before considering any changes to either fee.

Regarding changes to §3.70(o), Sierra Club agrees with the Commission and supports the requirement of having both the transferor and transferee sign for ownership transfer, with some flexibility where the transferor operator failed to do so.

The Commission appreciates Sierra Club's comments.

Regarding §3.70(r)(1), the Commission received similar comments from TXOGA, PBPA, and Texas Industry Project. These associations proposed extending the deadline for amending T-4 permits to December 31, 2025, noting that it will be challenging for operators to file by March 31, 2025. PBPA also suggested that any future proposals to shapefile submission include opportunity for public comment and stakeholder feedback.

The Commission disagrees with the proposal to extend the deadline to December 31, 2025. The federal gathering line rule required all operators to begin filing annual reports starting in March 2023. As such, operators should have all necessary information. This data is needed to accurately enter new Type C gathering line systems into the Pipeline Inspection System (PIPES). Additionally, the Commission released a Notice to Operators on February 29, 2024 to make operators aware of the new shapefile requirements.

Additionally, regarding §3.70(r), PBPA proposed to revise the amended rule to exclude Type R pipeline operators from submitting shapefiles with T-4 permit requests, noting that this goes beyond PHMSA's requirements, many operators have stated that they utilize other methods, and may not have GIS centerline data.

The Commission disagrees with PBPA's proposal to exclude Type R operators from shapefile requirements under §3.70(r). The data requested in the shapefile submissions is required for operators to differentiate between Type C and Type R pipelines. Thus, §3.70(r) will be adopted as proposed.

The Commission appreciates the input received from commenters. The Commission makes no changes in response to these comments. The adopted rule language is summarized in the paragraphs below.

The Commission adopts amendments in §3.70(i)(1)(A) and (B) to incorporate federal categories of pipelines and to clarify reporting requirements. In the Commission's rulemaking to amend §8.1 of this title (relating to General Applicability and Standards), which is adopted concurrently with these amendments to §3.70, the Commission incorporates minimum safety standards from PHSMA. PHMSA's standards extend reporting requirements to all gas gathering operators and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. The amendments to §3.70(i) incorporate federal pipeline classifications and ensure gas gathering lines are regulated consistent with PHMSA's requirements.

The adopted amendments in subsection (i)(2) and (3) and subsection (j) remove dates that were included in the rule when the fees were first adopted.

The Commission adopts amendments in subsection (o) to clarify the procedure for filing Form T-4B when the transferee operator is unable to obtain the signature of the transferor operator. This situation is addressed in the oil and gas context in §3.58 of this title (relating to Certificate of Compliance and Transportation Authority; Operator Reports) and the related Single-Signature Form P-4 process. The Commission adopts a similar process in subsection (o) because this situation also occurs with pipeline transfers.

The Commission adopts new subsection (r) to require updates in the permitting system related to gas gathering pipelines, indicating the federal categories as adopted in subsection (i). The amendments state that, beginning December 9, 2024, operators shall amend gas permits to include all gas gathering pipelines defined as Type A, Type B, Type C, or Type R in 49 CFR §192.8. The permit amendments shall be filed on the Commission's online permitting system by March 31, 2025.

The Commission adopts the amendments pursuant to Texas Natural Resources Code, §81.071, which authorizes the Commission to establish pipeline safety and regulatory fees to be assessed for permits or registrations for pipelines under the jurisdiction of the Commission's pipeline safety and regulatory program. Additionally, the Commission adopts the amendments pursuant to Texas Natural Resources Code §81.051 and §81.052, which provide the Commission with jurisdiction over all persons owning or operating pipelines in Texas and the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission; Texas Natural Resources Code §86.041 and §86.042, which allow the Commission broad discretion in adopting rules to prevent waste in the piping and distribution of gas, require records to be kept and reports made, and provide for the issuance of permits and other evidences of permission; Texas Natural Resources Code §111.131 and §111.132, which authorize the Commission to promulgate rules for the government and control of common carriers and public utilities; and Texas Utilities Code §§121.201 - 121.210, which authorize the Commission to adopt safety standards and practices applicable to the transportation of gas and associated pipeline facilities within Texas to the maximum degree permissible under, and to take any other requisite action in accordance with, 49 United States Code Annotated, §§60101, et seq. Texas Natural Resources Code §§81.051, 81.052, 86.041, 86.042, 111.131, and 111.132; Texas Utilities Code, §§121.201 - 121.210; and 49 United States Code Annotated, §§60101, et seq.

Cross-reference to statute: Texas Natural Resources Code, Chapter 81, Chapter 86, and Chapter 111, and Texas Utilities Code, Chapter 121; and 49 United States Code Annotated, Chapter 601.

§3.70. Pipeline Permits Required.

(a) Each operator of a pipeline or gathering system, other than an operator excluded under §8.1(b)(4) of this title (relating to General Applicability and Standards), subject to the jurisdiction of the Commission, shall obtain a pipeline permit, to be renewed annually, from the Commission as provided in this rule. Production or flow lines that are subject to §8.1(a)(1)(B) and (D) [~~§8.1(a)(1)(B) and (a)(1)(D)~~] of this title must comply with this section. All other production or flow lines as defined in this subsection are exempt from complying with this section. A production or flow line is piping used for production operations that generally occur upstream of gathering or other pipeline facilities. For the purposes of this subsection, piping used in "production operations" means piping used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids, and includes the following processes:

(1) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement; and

(2) associated production compression, gas lift, gas injection, or fuel gas supply.

(b) To obtain a new pipeline permit or to amend a permit because of a change of classification, an operator shall file an application for a pipeline permit on the Commission's online permitting system. The operator shall include or attach the following documentation and information:

(1) the contact information for the individual who can respond to any questions concerning the pipeline's construction, operation or maintenance;

(2) the requested classification and purpose of the pipeline or pipeline system as a common carrier, a gas utility or a private line;

(3) a sworn statement from the pipeline applicant providing the operator's factual basis supporting the classification and purpose being sought for the pipeline, including, if applicable, an attestation to the applicant's knowledge of the eminent domain provisions in Texas Property Code, Chapter 21, and the Texas Landowner's Bill of Rights as published by the Office of the Attorney General of Texas; [~~and~~]

(4) documentation to provide support for the classification and purpose being sought for the pipeline, if applicable; and

(5) any other information requested by the Commission.

(c) To renew an existing permit, to amend an existing permit for any reason other than a change in classification, or to cancel an existing permit, an operator shall file an application for a pipeline permit on the Commission's online filing system. The operator shall include or attach:

(1) the contact information for the individual who can respond to any questions concerning the pipeline's construction, operation, or maintenance; change in operator or ownership; or other change including operator cessation of pipeline operation;

(2) a statement from the pipeline operator confirming the current classification and purpose of the pipeline or pipeline system as a common carrier, a gas utility or a private line, if applicable; and

(3) any other information requested by the Commission.

(d) Upon receipt of a complete permit application, the Commission has 30 calendar days to issue, amend, or deny the pipeline permit as filed. If the Commission determines that the application is incomplete, the Commission shall promptly notify the applicant of the deficiencies and specify the additional information necessary to complete the application. Upon receipt of a revised application, the Commission has 30 calendar days to determine if the application is complete and issue, amend, or deny the pipeline permit as filed.

(e) If the Commission is satisfied from the application and the documentation and information provided in support thereof, and its own review, that the proposed line is[~~,~~] or will be laid, equipped, managed and operated in accordance with the laws of the state and the rules and regulations of the Commission, the permit may be granted. The pipeline permit, if granted, shall classify the pipeline as a common carrier, a gas utility, or a private pipeline based upon the information and documentation submitted by the applicant and the Commission's review of the application.

(f) This rule applies to applications made for new pipeline permits and to amendments, renewals, and cancellations of existing pipeline permits. The classification of a pipeline under this rule applies to extensions, replacements, and relocations of that pipeline.

(g) The Commission may delegate the authority to administratively issue pipeline permits.

(h) The pipeline permit, if granted, shall be revocable at any time after a hearing, held after 10 days' notice, if the Commission finds that the pipeline is not being operated in accordance with the laws of the state and the rules and regulations of the Commission including if the permit is not renewed annually as required in subsection (a) of this section.

(i) Each pipeline operator shall pay an annual fee based on the pipeline operator's permitted mileage of pipeline not later than [~~by August 31, 2018, for the initial year that the requirement is in effect, and by~~] April 1 of [~~for~~] each [~~subsequent~~] year.

(1) For purposes of calculating the mileage fee, the Commission will categorize pipelines into two groups.

(A) Group A includes transmission and gathering pipelines that are required by Commission rules to have a valid T-4 permit to operate and are subject to the regulations in 49 CFR Parts 192 and 195, such as natural gas transmission and storage pipelines, natural gas gathering pipelines defined as Type A, Type B, or Type C in 49 CFR §192.8, hazardous liquids transmission and storage pipelines, regulated rural [~~and~~] hazardous liquids gathering pipelines under 49 CFR §195.11, and hazardous liquid low-stress rural pipelines under 49 CFR §195.12.

(B) Group B includes pipelines that are required by Commission rules to have a valid T-4 permit to operate but are only subject to the reporting requirements [~~not subject to the regulations~~] in 49 CFR Parts 191 [~~192~~] and 195 such as Type R gathering pipelines as defined in 49 CFR §192.8, and reporting-regulated-only gathering lines as defined in 49 CFR §195.15. [~~Group B also includes gathering pipelines required to comply with §8.110 of this title (relating to Gathering Pipelines).~~]

(2) An operator of a Group A pipeline shall pay an annual fee of $20 per mile of pipeline based on the number of miles permitted to that operator as of [~~June 29, 2018, for the initial year that the requirement is in effect and as of~~] December 31 of [~~for~~] each [~~subsequent~~] year.

(3) An operator of a Group B pipeline shall pay an annual fee of $10 per mile of pipeline based on the number of miles permitted to that operator as of [~~June 29, 2018, for the initial year that the requirement is in effect and as of~~] December 31 of [~~for~~] each [~~subsequent~~] year.

(4) Any pipeline distance that is a fraction of a mile will be considered as one mile and will be assessed a $20 or $10 fee, as appropriate.

(5) Fees due to the Commission for mileage transferred from one operator to another operator pursuant to subsection (o) of this section will be captured in the next mileage fee to be calculated on the following December 31 and paid by the new operator.

(j) Each [~~Beginning October 1, 2018, each~~] pipeline operator shall pay a $500 permit processing fee for each new permit application and permit renewal.

[~~(1) From October 1, 2018, to August 31, 2020, the permit renewal date for a pipeline operator who has an existing, valid permit in the Commission's online filing system will be the date shown in the online filing system on June 29, 2018, when the pipeline mileage is calculated for purposes of paying the mileage fee. A permit renewal date will not be affected or changed by an operator requesting or receiving a permit amendment.~~]

[~~(2)~~] Each operator [~~Beginning September 1, 2020, operators~~] shall file the [~~their~~] annual renewals as follows:

(1) [~~(A)~~] Companies with names beginning with letters A through C shall file in February;

(2) [~~(B)~~] Companies with names beginning with letters D through E shall file in March;

(3) [~~(C)~~] Companies with names beginning with letters F through L shall file in April;

(4) [~~(D)~~] Companies with names beginning with letters M through P shall file in May;

(5) [~~(E)~~] Companies with names beginning with letters Q through T shall file in June; and

(6) [~~(F)~~] Companies with names beginning with letters U through Z and companies with names beginning with numerical values or other symbols shall file in July.

(k) Each operator [~~Beginning September 1, 2020, operators~~] shall comply with the following:

(1) If a permit is transferred, in the Commission fiscal year of the transfer the acquiring operator shall renew that permit in its designated month pursuant to subsection (j) [~~(j)(2)~~] of this section. If the acquiring operator receives a transferred permit in a Commission fiscal year and its renewal month has already passed, the acquiring operator shall pay the renewal fee upon transfer.

(2) If an operator adds a new permit and pays the new permit fee, the operator is not required to pay the renewal fee for that permit in the same Commission fiscal year.

(3) If an operator adds a new permit after its renewal month has passed, the new permit shall be renewed the following Commission fiscal year in the operator's designated month pursuant to subsection (j) [~~(j)(2)~~] of this section.

(l) A pipeline operator who fails to renew a permit on or before the renewal deadline which is the last day of the operator's required filing month as specified in subsection (j) of this section shall pay a late-filing fee as follows:

(1) $250, if the renewal application is received within 30 calendar days after the renewal deadline date;

(2) $500, if the renewal application is received more than 30 calendar days and no more than 60 calendar days after the renewal deadline date; and

(3) $700, if the renewal application is received more than 60 calendar days after the renewal deadline date.

(4) If the renewal application is not received within 90 calendar days of the renewal deadline date, the Commission may assess a penalty and/or revoke the operator's permit in accordance with subsection (h) of this section.

(m) A pipeline operator with a total mileage of 50 miles or less of pipeline who fails to pay the annual mileage fee as specified in subsection (i) of this section shall pay a late-filing fee as follows:

(1) $125, if the fee is received within 30 calendar days of April 1;

(2) $250, if the fee is received more than 30 calendar days and no more than 60 calendar days after April 1; and

(3) $350, if the fee is received more than 60 calendar days after April 1.

(4) If the fee is not received within 90 calendar days of April 1, the Commission may assess a penalty and/or revoke the operator's permit in accordance with subsection (h) of this section.

(n) A pipeline operator with a total mileage of more than 50 miles of pipeline who fails to pay the annual mileage fee shall pay a late-filing fee as follows:

(1) $250, if the fee is received within 30 calendar days of August 31 for the initial year that the requirement is in effect and April 1 for each subsequent year;

(2) $500, if the fee is received more than 30 calendar days and no more than 60 calendar days after August 31 for the initial year that the requirement is in effect and April 1 for each subsequent year; and

(3) $700, if the fee is received more than 60 calendar days after August 31 for the initial year that the requirement is in effect and April 1 for each subsequent year.

(4) If the fee is not received within 90 calendar days of August 31 for the initial year that the requirement is in effect or April 1 for each subsequent year, the Commission may assess a penalty and/or revoke the operator's permit in accordance with subsection (h) of this section.

(o) A pipeline operator who has been issued a permit and is transferring the pipeline or a portion of the pipeline included on the permit to another operator shall file a notification of transfer with the Commission within 30 days following the transfer. The transferee and transferor operators [~~An operator~~] shall [~~may~~] file a fully executed Form T-4B as a notification of transfer. The Commission may use a fully executed Form T-4B to remove the pipeline that is the subject of the transfer from the transferor operator and assign the mileage to the transferee operator for calculation of the annual mileage fee. The transferee operator [~~to which the pipeline has been transferred~~] shall amend its permit to include the pipeline or portion of the pipeline within 30 days following the Commission's approval of the transfer or the operator may be subject to a penalty for operating without a permit pursuant to subsection (p) of this section.

(1) A transferee operator may file a Form T-4B signed only by the transferee operator as a notification of transfer with the Commission only upon presenting to the Commission for its review, concurrently with Form T-4B:

(A) evidence that the transferee operator made a good faith effort to procure the transferor operator's signature; and

(B) documentation establishing that the transferee operator has a legal right to operate the pipeline.

(2) Prior to approving a single-signature Form T-4B filed pursuant to paragraph (1) of this subsection, the Commission shall issue notice to the transferor operator, providing the operator 15 days to contest the transfer and request a hearing. Upon receipt of a timely response requesting a hearing, the matter shall be referred to the Hearings Division for adjudication as a contested case.

(p) A pipeline operator who operates a pipeline without a permit, with an expired permit, or who otherwise fails to comply with this section, may be assessed a penalty as prescribed in §8.135 of this title (relating to Penalty Guidelines for Pipeline Safety Violations).

(q) Interstate pipelines are exempt from the fee requirements of this section.

(r) Beginning December 9, 2024, operators shall comply with the following.

(1) All gas permits shall be amended to include all gas gathering pipelines defined as Type A, Type B, Type C, or Type R in 49 CFR §192.8. The permit amendments shall be filed on the Commission's online permitting system by March 31, 2025. The amendment shapefile shall indicate each segment as Type A, Type B, Type C, or Type R, and include any other information requested by the Commission.

(2) A gas permit will not be eligible for renewal if the permit has not been amended by March 31, 2025, in accordance with paragraph (1) of this subsection. If the gas permit does not have any gas gathering pipelines to be amended or added, the operator shall include with its 2025 renewal submission a statement on the submitted cover letter attesting to that fact. The Commission may request additional information as necessary to confirm the statement.

This agency hereby certifies that the rules as adopted have been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on November 19, 2024.

Filed with the Office of the Secretary of State on November 19, 2024.

DocuSigned by:
Christi Craddick
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Christi Craddick, Chairman

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ATTEST:
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Secretary of the Commission

Haley Cochran
Haley Cochran

Assistant General Counsel
Office of General Counsel
Railroad Commission of Texas

The Railroad Commission of Texas adopts amendments to §§8.1, 8.101, 8.110, 8.115, 8.125, 8.201, 8.208, 8.209, and 8.210, relating to General Applicability and Standards; Pipeline Integrity Assessment and Management Plans for Natural Gas and Hazardous Liquids Pipelines; Gathering Pipelines; New Construction Commencement Report; Waiver Procedure; Pipeline Safety and Regulatory Program Fees; Mandatory Removal and Replacement Program; Distribution Facilities Replacements; and Reports. Sections 8.1, 8.115, and 8.209 are adopted with changes to the proposed text published in the August 30, 2024, issue of the Texas Register (49 TexReg 6652) and the remaining rules are adopted without changes. The Commission adopts these amendments to capture the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) latest standards, to clarify areas of the rules that staff receives regular inquires on, and to clarify how pipeline operators should report and file with Commission.

The Commission received six comments, four of which were from associations (Permian Basin Petroleum Association (PBPA), Pipeline Safety Trust, Sierra Club Lone Star Chapter (Sierra Club), and Texas Oil and Gas Association (TXOGA)). Two companies, Atmos Energy Corporation's Mid-Texas Division and West Texas Division (Atmos) and Texas Gas Service (TGS) also commented. The Commission appreciates these comments.

Regarding the amendments proposed in §8.1(a)(1)(B), PBPA and TXOGA commented that PHMSA regulations in 49 CFR §192.8 associate Type C facilities only with Class 1 locations. Thus, the Commission should remove Type C from §8.1(a)(1)(B).

The Commission agrees and adopts §8.1(a)(1)(B) with a change to remove "Type C."

In addition, PBPA and TXOGA requested clarification regarding the meaning of "first point of measurement" in §8.1(a)(1)(B). TXOGA suggested that "first point of measurement" be defined as a measurement which occurs after final processing, before transportation to a third party for sales. TXOGA also suggested that the Commission exempt measurement methods utilizing allocation meters, multi-phase flow meters, bulk separation/test meters, and well performance surveillance meters associated with production operations and prior to final separation and processing at central tank batteries.

The Commission notes that "first point of measurement" is the first point of measurement required under §3.27 of this title, relating to Gas to be Measured and Surface Commingling of Gas. The Commission disagrees that the definition should exempt the measurement methods proposed by TXOGA. Section 8.1(a)(1)(B) was added to the chapter in 2009 to address the regulation of production pipelines located in more populated areas (Class 2, 3, and 4 locations). This section continues to apply only to production pipelines in Class 2, 3, and 4 locations and includes the entirety of the pipeline that is located in a Class 2, 3, or 4 location.

PBPA requested clarification regarding whether "Group A" fees are only applicable to PHMSA-defined transmission and gathering pipelines and do not apply to production lines defined in §8.1(a)(1)(B).

The Commission makes no change in response to this comment. Production pipelines covered under §8.1(a)(1)(B) are subject to the regulations in 49 CFR Part 192 and require inspections. They are currently subject to Group A fees and Group A fees will continue to apply.

The Commission received three comments on its proposed changes to §8.1(b), which update the minimum safety standards and adopt by reference the Department of Transportation (DOT) pipeline safety standards found in 49 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 195, Transportation of Hazardous Liquids by Pipeline. PBPA expressed support for the proposed amendments. Sierra Club also expressed support but noted the Commission should have acted sooner to incorporate the federal standards. Atmos requested clarification regarding whether the change will incorporate rules finalized by PHMSA by December 9, 2024, but not effective by December 9, 2024, such as the leak detection and repair rulemaking.

The Commission confirms that the leak detection and repair (LDAR) rulemaking is not incorporated by reference. The federal rules that are incorporated into §8.1(b) as of December 9, 2024 (the effective date of these rule amendments) are the rules resulting from the rulemakings listed in the Commission's preamble to the proposed amendments published in the August 30, 2024, issue of the Texas Register (49 TexReg 6652). Those rulemakings are also listed below in the paragraph summarizing the amendments to §8.1(b).

In §8.101, the Commission proposed changes to clarify which pipelines referenced in 49 CFR Part 195 are subject to the rule's requirements. The amendments also align Texas integrity rules with the federal requirements and state that operators of pipelines subject to 49 CFR §192.710 shall follow the remediation requirements.

Atmos commented in support of the proposed amendments to §8.101. The Commission appreciates this comment.

PBPA and TXOGA requested that the title of Figure 2 in §8.101(b)(2) be revised from "Liquid Pipelines" to "Liquid Pipelines Subject to 49 CFR Part 195 Requirements." The commenters noted that the Commission generally requires that interstate, rural, non-regulated systems be permitted. Non-regulated systems that are permitted should not also be subject to Pipeline Integrity Assessment and Management Plans in §8.101. This is stated in proposed rule language and for consistency should also be clearly referenced in the title of Figure 2.

The Commission declines to make this change. The applicability of the section to pipeline facilities used in the transportation of hazardous liquids or carbon dioxide subject to 49 CFR Part 195 is stated in subsection (b) and an additional change to the figure is unnecessary. In addition, updating the title of this figure would create inconsistency with other figures in Chapter 8, some of which were not included in this proposal.

The Pipeline Safety Trust commented that the reassessment interval of ten years for natural gas and hazardous liquids pipelines is too long. Conditions can change quickly over a decade, and frequent assessment is needed to ensure operators are repairing and monitoring their pipelines effectively. The Pipeline Safety Trust suggested that the Commission change the requirement for reassessment intervals to not exceed five years for both §8.101(b)(1)(F)(i) and (ii).

The Commission declines to make the requested change because the Commission does not support decreasing the interval to five years without first seeking input from affected operators. Changing the interval from every ten years to every five years would create a significant cost for operators, and they should have an opportunity to comment. The Commission will consider the Pipeline Safety Trust's suggestion in assessing future changes to §8.101.

Regarding amendments proposed in §8.115, Atmos commented that it has worked with the Pipeline Safety Division since 2020 to improve reporting on construction projects. Based on those filings, Atmos believes the intent of new subsection §8.115(a)(6) is to require reporting on projects less than three miles in length only if the project results in a new distribution system ID. To clarify the language further, Atmos suggested that "10" be replaced with "3" in subsection (a)(6) and the language relating to a new subdivision be removed. Also, Atmos suggested a change to §8.115(b) to clarify that extension requests should be made by emailing PS-48Reports@rrc.texas.gov.

The Commission agrees with Atmos's suggestions and adopts §8.115 with changes based on Atmos's comments. The Commission incorporates Atmos's suggestions into §8.115(a)(5) and moves existing language from subsection (a)(5) relating to systems at least three miles in length but less than ten miles in length to subsection (a)(6). With this change, adopted subsection (a)(5) will address systems less than three miles in length and subsection (a)(6) will address those at least three miles but less than ten miles.

Sierra Club also commented on the proposed amendments to §8.115. Sierra Club expressed support for the requirement for a new liquefied natural gas (LNG) plant or LNG facility construction to notify the Commission not later than 60 days before beginning construction. Sierra Club disagreed that a reporting exemption should be provided to facilities less than three miles in length and recommended this exemption be removed.

The Commission disagrees and declines to remove the exemption. The Commission notes that due to the clarifying changes adopted in §8.115(a)(5) and (a)(6), if construction of a new liquefied petroleum gas distribution system, natural gas distribution system, or master meter system less than three miles in length results in a new distribution system ID, the operator is subject to a reporting requirement. Thus, the exemption only applies when construction is less than three miles in length and does not result in a new distribution system ID. The requirements in §8.115 are intended to ensure the Commission receives notification of large replacement projects for inspection. While operators are not required to report smaller replacement projects, the Commission still performs inspections for smaller replacement projects.

Atmos commented in support of the amendments to §8.125. The Commission appreciates this comment.

Atmos also commented in support of the amendments to §8.201, as long as the payment system can capture large amounts.

The Commission performed testing to ensure the payment portal can capture large amounts.

The Sierra Club commented expressing support for the updates in §8.208. However, Sierra Club opposes the removal of a mandatory reporting requirement in favor of a requirement to maintain records. Sierra Club stated it believes it is better public policy for the operators to report annually to the division on their efforts to replace compression couplings.

The Commission declines to make changes in response to this comment. Since the implementation of §8.208, operators have completed the replacement of all known compression couplings that required removal. However, the Commission will still inspect facilities for compliance with §8.208 during standard comprehensive inspections.

Atmos and TGS commented regarding the proposed amendments to §8.209(j), which were intended to clarify how an operator of a gas distribution system that is subject to the requirements of §7.310 of this title (relating to System of Accounts) may account for the investment and expense incurred to comply with the requirements of §8.209. The comments state that operators have calculated and applied interest in accordance with the rule and on a consistent basis since the rule's original adoption. Atmos provided more information regarding the methodology of the calculation, which records simple interest on the balance of the designated regulatory asset accounts using a monthly interest rate equal to one twelfth of the pre-tax weighted average cost of capital last approved by the Commission for each division. Atmos expressed support for a modification to the proposed language to clarify that methodology.

The Commission adopts §8.209 with changes to address these concerns. The language adopted in subsection (j)(1)(C) will allow the operator to record simple interest on the balance in the designated distribution facility replacement accounts using a monthly interest rate equal to one-twelfth of the pre-tax weighted average cost of capital last approved for the utility by the Commission.

Atmos and the Pipeline Safety Trust commented in support of the proposed amendments to §8.210(e). Sierra Club also expressed support, stating the amendment was a welcome and needed change. The Commission appreciates these comments.

The Pipeline Safety Trust commented suggesting the Commission include additional reporting requirements for estimated leak volume. The comment stated including estimated leak volume will allow the Commission to obtain more information regarding the impact of the leaks, and may help inform other state agencies, such as the Texas Commission on Environmental Quality, on leak impacts.

The Commission declines to include estimated leak volume at this time. PHMSA's pending leak detection and repair rule may impact Commission requirements in §8.210. Thus, the Commission will wait to consider further changes to §8.210 until PHMSA's rule is finalized.

The Commission appreciates the input from all those who submitted comments.

The adopted rule language is summarized in the paragraphs below.

The Commission adopts amendments to §8.1(a)(1)(B) to clarify the requirements for gas production lines located in populated areas. As stated above, the Commission adopts §8.1(a)(1)(B) with a change to remove Type C pipelines based on the comments. The amendments in §8.1(a)(1)(B) also impact current requirements under §3.70, relating to Pipeline Permits Required. The Commission adopts amendments to §3.70 concurrently to these amendments to rules in Chapter 8.

The Commission adopts an amendment in §8.1(a)(1)(D) to clarify that all offshore pipelines (both production and gathering) located in Texas waters shall follow 49 CFR 192 and 49 CFR 195.

The Commission adopts an amendment to §8.1(b) to update the minimum safety standards and to adopt by reference the Department of Transportation (DOT) pipeline safety standards found in 49 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 195, Transportation of Hazardous Liquids by Pipeline. Current subsection (b) adopted the federal pipeline safety standards as of September 6, 2021. The amendment changes the date to December 9, 2024, the effective date of the rule amendments, to capture the following federal PHMSA pipeline safety rule amendments: Docket No. PHMSA-2011-0023: Amdt. Nos. 191-30 and 192-129, revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas gathering pipelines effective May 16, 2022; Docket No. PHMSA-2011-0023: Amdt. Nos. 191-31 and 192-131, effective May 16, 2022, denying a petition for reconsideration of the final rule titled "Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments" and making clarifications and two technical corrections to that rulemaking; Docket No. PHMSA-2013-0255: Amdt. Nos. 192-130 and 195-105, revising the Federal Pipeline Safety Regulations applicable to most newly constructed and entirely replaced onshore gas transmission, Type A gas gathering, and hazardous liquid pipelines with diameters of six inches or greater, effective October 5, 2022; Docket No. PHMSA-2013-0255: Amdt. Nos. 192-134 and 195-106, effective August 1, 2023, making editorial and technical corrections clarifying the regulations promulgated in its April 8, 2022, final rule titled "Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards" for certain gas, hazardous liquid, and carbon dioxide pipelines; Docket No. PHMSA-2011-0023: Amdt. No. 192-132, amending the federal pipeline safety regulations in 49 CFR Part 192 to improve the safety of onshore gas transmission pipelines effective May 24, 2023; Docket No. PHMSA-2011-0023: Amdt. No. 192-133, also effective May 24, 2023, making necessary technical corrections in 49 CFR Part 192 to ensure consistency within, and the intended effect of, a recently issued final rule titled "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments"; and Docket No. PHMSA-2016-0002, Amdt. Nos. 192-135, 195-107, amending 49 CFR Parts 192 and 195 regarding periodic updates of regulatory references to technical standards and miscellaneous amendments which amended the Federal pipeline safety regulations (PSRs) to incorporate by reference all or parts of more than 20 new or updated voluntary, consensus industry technical standards, effective June 28, 2024.

The Commission adopts amendments in §8.1(b)(3) to align the rule text with federal exemptions allowed under 49 CFR §199.2(c)(1).

The Commission adopts several amendments in §8.101. First, the amendments in subsection (b) clarify which pipelines referenced in 49 CFR Part 195 are subject to subsection (b)'s requirements - pipeline facilities used in the transportation of hazardous liquids or carbon dioxide. The current rule's figure clarified which pipelines were subject to the requirements but the rule language was unclear. The

Commission also adopts amendments in §8.101(b)(1)(C) and (b)(1)(F) to align state integrity rules with the federal requirements. Amendments in §8.101(d) state that operators of pipelines subject to 49 CFR §192.710 shall follow the remediation requirements required by 49 CFR §192.710(f). Corresponding changes are made to a Figure in the section.

The Commission adopts amendments in §8.110 to incorporate PHMSA definitions of types of gathering lines. For gas, the amendments incorporate new terms "Type C" and "Type R"; for liquid, the amendments incorporate the designation "reporting-regulated-only" gathering lines. These amendments incorporate the newer terminology consistent with federal rules.

The Commission adopts amendments to §8.115 with changes from the proposal. Section 8.115 requires operators of liquefied natural gas (LNG) facilities to report the construction of a new LNG plant or LNG facility to the Commission. The Commission adopts amendments in current §8.115(a)(4), renumbered as paragraph (5), to clarify that for new, relocated, or replacement construction on liquified petroleum gas distribution systems, natural gas distribution systems, or master meter systems less than three miles in length, no construction notification is required. However, new construction for systems less than three miles in length is required to be reported if the construction results in a new distribution system ID. The Commission adopts paragraphs (5) and (6) with changes to better reflect the intent of reporting requirements. Amendments in current subsection (a)(7), renumbered as paragraph (8), exempt Type R gas gathering pipelines and the "reporting-regulated-only" liquid gathering pipelines from the construction notification requirement. Type C pipelines must still comply with this requirement. The other amendments in §8.115 allow electronic filing of required forms and reports either through email or using the Commission's online application for inspections and permits, which is currently called the Pipeline Inspection Permitting System (PIPES) and is available on the Commission's website. Section 8.115 is adopted with another change to specify how to file a request for an extension.

The Commission adopts amendments to §8.125(e) to change terminology to align with the Commission's online filing system called CASES. Applications previously referred to as "dockets" are now called "cases." In addition, amendments in subsection (e) require that a notice of a waiver application include the division's email address in addition to other required contents. Similarly, amendments in subsection (f) allow affected persons who have received notice of a waiver application to object to, support, or request a hearing via email.

The Commission adopts amendments to §8.201(b)(2) and (c)(1) to require payments through the Commission's online application for inspections and permits, PIPES.

The Commission adopts amendments in §8.208(j) to change reporting requirements. Commission staff states operators no longer need to file these reports with the Commission. Instead, they should maintain a progress report annually and provide to the Commission upon request.

The Commission adopts an amendment in §8.209(a) to clarify that 49 CFR §192.1003(b) may provide an exemption. The Commission also adopts amendments in subsection (j) to clarify how an operator of a gas distribution system that is subject to the requirements of §7.310 of this title (relating to System of Accounts) may account for the investment and expense incurred to comply with the requirements of §8.209. The Commission adopts §8.209 with changes based on comments from Atmos and TGS. The language adopted in subsection (j)(1)(C) will allow the operator to record simple interest on the balance in the designated distribution facility replacement accounts using a monthly interest rate equal to one-twelfth of the pre-tax weighted average cost of capital last approved for the utility by the Commission.

The Commission adopts amendments in §8.210(e) to require an operator to submit the PS-95 even if there are no leaks discovered. Additional amendments add references to the Commission's online permit application.

The Commission adopts the amendments under Texas Natural Resources Code, §81.051 and §81.052, which give the Commission jurisdiction over all common carrier pipelines in Texas, persons owning or operating pipelines in Texas, and their pipelines and oil and gas wells, and authorize the Commission to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission, including such rules as the Commission may consider necessary and appropriate to implement state responsibility under any federal law or rules governing such persons and their operations; Texas Natural Resources Code, §§117.001-117.101, which give the Commission jurisdiction over all pipeline transportation of hazardous liquids or carbon dioxide and over all hazardous liquid or carbon dioxide pipeline facilities as provided by 49 U.S.C. Section 60101, et seq.; and Texas Utilities Code, §§121.201-121.210, 121.213-121.214, which authorize the Commission to adopt safety standards and practices applicable to the transportation of gas and to associated pipeline facilities within Texas to the maximum degree permissible under, and to take any other requisite action in accordance with, 49 United States Code Annotated, §§60101, et seq.

Statutory authority: Texas Natural Resources Code, §81.051, §81.052, and §§117.001-117.101; Texas Utilities Code, §§121.201-121.211; §§121.213-121.214; §121.251 and §121.253, §§121.5005-121.507; and 49 United States Code Annotated, §§60101, et seq.

Cross-reference to statute: Texas Natural Resources Code, Chapter 81 and Chapter 117; Texas Utilities Code, Chapter 121; and 49 United States Code Annotated, Chapter 601.

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 pipelines and production facilities, in Class 2, 3, or 4 locations as defined by 49 CFR §192.5, beginning after the first point of measurement and ending as defined by 49 CFR Part 192 as the beginning of an onshore gathering line. These [~~The gathering and~~] production pipelines and production facilities [~~beyond this first point of measurement~~] shall be subject to 49 CFR §192.8(c) in determining if these pipelines and facilities are Type A **or** Type B~~, or Type C,~~ and subject to the rules in 49 CFR §192.9 for Type A **or** Type B~~, or Type C~~ pipelines [~~§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 §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. These facilities shall be subject to 49 CFR Part 192 for natural gas pipelines and 49 CFR Part 195 for hazardous liquid pipelines.

(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 December 9, 2024 [~~September 13, 2021~~].

(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, except operators that only operate one or more master meter systems, as defined in 49 CFR §191.3, 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 regulated by this chapter, 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) Retention of DOT filings. 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 retain a copy of that document or information. Such person is not required to concurrently file that document or information with the Division unless another rule in this chapter requires the document or information to be filed with the Division or unless the Division requests a copy.

(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.

SUBCHAPTER B. REQUIREMENTS FOR ALL PIPELINES

§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 <u>pipeline facilities used in the transportation of hazardous liquids or carbon dioxide</u>

subject to 49 CFR Part 195 shall have designated 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; [~~or~~]

(iv) for gas pipelines only, guided wave ultrasonic testing (GWUT);

(v) for gas pipelines only, excavation with direct in situ examination; or

(vi) [~~(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; and [~~.~~]

(F) re-assessment intervals not to exceed the following:

(i) for pipelines subject to 49 CFR Part 195, a maximum interval of 10 years for onshore line pipe that can accommodate inspection by means of in-line inspection tools; or

(ii) for pipelines subject to 49 CFR Part §192.710, a maximum interval of 10 years.

(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:

Figure 1: 16 TAC §8.101(b)(2) (No change.)

Figure 2: 16 TAC §8.101(b)(2)

~~Figure 2: 16 TAC §8.101(b)(2)~~

(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. For pipelines subject to 49 CFR §192.710, an operator shall follow the remediation requirements required by 49 CFR §192.710(f).

(e) 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.

§8.110. Gathering Pipelines.

(a) Scope. This section applies to the following gathering pipelines:

(1) Type C natural gas gathering pipelines as defined under 49 CFR §192.8 [~~located in a Class 1 location not regulated by 49 CFR §192.8 or §8.1 of this title (relating to General Applicability and Standards)~~]; [~~and~~]

(2) Type R natural gas gathering pipelines as defined under 49 CFR §192.8; and

(3) [~~(2)~~] hazardous liquids and carbon dioxide gathering pipelines as defined under 49 CFR §195.15 [~~located in a rural area as defined by 49 CFR §195.2 and not regulated by 49 CFR §195.1, 49 CFR §195.11, or §8.1 of this title~~].

(b) Safety. Each operator of a gathering pipeline described in subsection (a) of this section shall take appropriate action using processes and technologies that are technically feasible, reasonable, and practicable to correct a hazardous condition that creates a risk to public safety.

(c) Reporting.

(1) Each operator of a gas gathering pipeline described in subsection (a) of this section shall comply with §8.210(a) of this title (relating to Reports).

(2) Each operator of a hazardous liquids pipeline described in subsection (a) of this section shall comply with §8.301(a)(1)(B) and (a)(2)(B) of this title (relating to Required Records and Reporting) except that the initial telephonic report is not required.

(d) Investigation.

(1) Each operator of a gathering pipeline described in subsection (a) of this section shall

conduct its own investigation and cooperate with the Commission and its authorized representatives in the investigation of any of the following:

(A) an accident as defined by 49 CFR §195.50;

(B) an incident as defined by 49 CFR §191.3;

(C) a threat to public safety; or

(D) a complaint related to operational safety.

(2) Each operator shall provide the Commission reasonable access to the operator's facilities, provide the Commission any records related to such facilities, and file such reports or other information necessary to determine whether there is a threat to the continuing safe operation of the pipeline.

(e) Corrective action and prevention of recurrence. As a result of the investigations authorized under subsection (d) of this section, the Commission may require the operator to submit a corrective action plan to the Commission to remediate an accident, incident, or other hazardous condition that creates a risk to public safety, or to address a complaint related to public safety. Upon the Commission's review and approval of the corrective action plan, the operator shall complete the corrective action. No provision of this rule prevents the operator from implementing any corrective action at any time the operator deems necessary or prudent to correct or prevent a threat to the safe operation of the gathering pipeline and pipeline facilities.

§8.115. New Construction Commencement Report.

(a) An operator shall notify the Commission before the construction of pipelines and other facilities as follows.

(1) For construction of a new, relocated, or replacement pipeline 10 miles in length or longer including liquified petroleum gas distribution systems, natural gas distribution systems, and master meter systems 10 miles in length or longer, an operator shall notify the Commission not later than 60 days before construction.

(2) For construction of a new LNG plant or LNG facility, an operator shall notify the Commission not later than 60 days before construction.

(3) [~~(2)~~] Except as provided in paragraphs [~~(4) and~~] (5) and (6) of this subsection, for construction of a new, relocated, or replacement pipeline at least one mile in length but less than 10 miles, an operator shall notify the Commission not later than 30 days before construction.

(4) [~~(3)~~] For installation of any permanent breakout tank, an operator shall notify the

Commission not later than 30 days before installation. For installation of mobile, temporary, or prefabricated breakout tanks, an operator shall notify the Commission upon placing the mobile, temporary, or prefabricated breakout tank in service.

(5) [(4)] For ~~liquefied petroleum gas distribution systems, natural gas distribution systems, or master meter systems, no construction notification is required for~~ new, relocated, or replacement construction **on liquified petroleum gas distribution systems, natural gas distribution systems, or master meter systems** less than three miles in length, **no construction notification is required unless new construction results in a new distribution system ID. If the construction results in a new distribution system ID, the operator shall either**:

(A) notify the Commission not later than 30 days before construction by filing a Form PS-48 New Construction Report for every initial construction; or

(B) provide to the Commission a monthly report that reflects all known projects planned to be completed in the following 12 months, all projects that are currently in construction, and all projects completed since the prior monthly report. The report should provide the status of each project, the city and county of each project, a description of each project, and the estimated starting and ending date. These monthly reports shall be filed by email to PS-48Reports@rrc.texas.gov.

(6) For new, relocated, or replacement construction **on liquified petroleum gas distribution systems, natural gas distribution systems, or master meter systems** at least three miles in length but less than 10 miles in length, an operator shall either:

(A) notify the Commission not later than 30 days before construction by filing a Form PS-48 New Construction Report for every relocated or replacement construction; or

(B) provide to the Commission a monthly report that reflects all known projects planned to be completed in the following 12 months, all projects that are currently in construction, and all projects completed since the prior monthly report. The report should provide the status of each project, the city and county of each project, a description of each project, and the estimated starting and ending date. These monthly reports shall be filed by email to PS-48Reports@rrc.texas.gov.

~~**(6)** [(5)] For the construction of a new liquefied petroleum gas distribution system, natural gas distribution system, or master meter system less than 10 miles in length in a new subdivision or that results in a new distribution system ID, an operator shall either:~~

~~(A) notify the Commission not later than 30 days before construction by filing a Form PS-48 New Construction Report [Form PS-48] for every initial construction; or~~

~~(B) provide to the Commission a monthly report that reflects all known~~

~~projects planned to be completed in the following 12 months, all projects that are currently in construction, and all projects completed since the prior monthly report. The report should provide the status of each project, the city and county of each project, a description of each project, and the estimated starting and ending date.~~

(7) [~~(6)~~] For construction of a sour gas pipeline and/or pipeline facilities, as defined in §3.106 of this title (relating to Sour Gas Pipeline Facility Construction Permit), an operator shall notify the Commission not later than 30 days before construction by filing Form PS-48 and Form PS-79.

(8) [~~(7)~~] Pipelines subject to §8.110(a)(2) and (3) [~~§8.110~~] of this title (relating to Gathering Pipelines) are exempt from the construction notification requirement.

(b) Any of the notifications required by subsection (a) of this section, unless an operator elects to use the alternative notification allowed by subsection (a)(5) or (a)(6) [~~(a)(4)~~] of this section, shall be made by filing a Form PS-48 New Construction Report using the Commission's online application available on the Commission's website. The report shall include [~~with the Commission Form PS-48 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. If a notification is not feasible because of an emergency, an operator must notify the Commission as soon as practicable. A Form PS-48 that has been filed with the Commission shall expire if construction is not commenced within eight months of date the report is filed. An operator may submit one extension, which will keep the report active for an additional six months. **Extension requests shall be made by emailing PS-48Reports@rrc.texas.gov.** After one extension, the Form PS-48 will expire.

§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. An operator shall request a waiver prior to performing any activities that would fall under the waiver.

(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 notice [~~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 applicant shall file all return receipts with the Division as proof of notice. The notice shall include:

(A) a copy of the application;

(B) a description of [~~describe~~] the nature of the waiver sought;

(C) a statement [~~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~~]

(D) [~~shall include~~] the case [~~docket~~] number of the application;[~~, and~~]

(E) the mailing address of the Division; and

(F) the Division's email address safety@rrc.texas.gov . [~~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 case [~~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; [~~and~~]

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

(D) be filed with the Commission by email to safety@rrc.texas.gov.

(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 Hearings Division for the preparation of an order.

(B) The director shall not recommend that the Commission grant the waiver if the application was filed to correct an existing violation, to avoid the expense of safety compliance, or filed after the applicant already engaged in activities covered by the proposed waiver. 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 and orders.

(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 Hearings Division, which shall set and conduct the hearing in accordance with Chapter 1 of this title (relating to Practice and Procedure).

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

(i) 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).

SUBCHAPTER C. REQUIREMENTS FOR 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. Payments shall be made using the Commission's online application available on the Commission's website.

(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 Oversight and 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. <u>Payments shall be made using the Commission's online application available on the Commission's website.</u>

(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 Oversight and 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.

§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 January 15, 2025, and annually [~~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 maintain [~~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 the prior calendar year [~~that reporting period~~]. Each operator shall retain this progress report and shall provide a copy of the report to the Commission upon request.

§8.209. Distribution Facilities Replacements.

(a) Unless exempted by 49 CFR §192.1003(b), this [~~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) Each operator must establish 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.

(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. 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 5% or greater but less than 7.5% is a Priority 1 segment and an operator must remove or replace no less than 10% of the original inventory per year; and

(2) a segment with an annualized steel service line leak rate of less than 5% is a Priority 2 segment. An operator is not required to remove or replace any Priority 2 segments; however, upon discovery of a leak on a Priority 2 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) All replacement programs require a minimum annual replacement of 8% of the pipeline segments or facilities posing the greatest risk in the system 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 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 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 work plan for removal or replacement for the current calendar year, the implementation of which is subject to review and amendment by the Division. Each operator must notify the 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 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 **using a monthly interest rate equal to one-twelfth of** [~~based on~~] the pretax **weighted average** 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.

(k) A distribution gas pipeline facility operator shall not install as a part of the operator's underground system a cast iron, wrought iron, or bare steel pipeline. A distribution gas pipeline facility operator shall replace any known cast iron pipelines installed as part of the operator's underground system not later than December 31, 2021.

§8.210. Reports.

(a) Incident report.

(1) Telephonic report. At the earliest practical moment but no later than one hour following confirmed 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 §191.3. 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 incident;

(C) the time of the incident;

(D) the number of fatalities and/or personal injuries;

(E) the phone number of the operator;

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

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

(2) This paragraph applies to each operator of a gas distribution system that is subject to the requirements of 49 CFR Part 192. Such operator shall also provide the following information to the Division when the information is known by the operator:

(A) the cost of gas lost;

(B) estimated property damage to the operator and others;

(C) any other significant facts relevant to the incident; and

(D) other information required under federal regulations to be provided to the Pipeline and Hazardous Materials Safety Administration or a successor agency after a pipeline incident or similar incident.

(3) Written report.

(A) Following the initial telephonic report for incidents described in paragraph (1) of this subsection, the operator shall retain its records and provide to the Commission upon request the applicable written reports submitted to the Department of Transportation. Operators of gas gathering pipelines regulated by §8.110 (relating to Gathering Pipelines) shall file with the Commission within 30 calendar days after the date of the telephonic report a written report on an incident described in paragraph (1) of this subsection utilizing the applicable form from the Department of Transportation.

(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 incident not otherwise required to be reported.

(b) Pipeline safety annual reports. Each gas company shall retain the annual report for its intrastate systems in the same manner as required by 49 CFR Part 191. A gas company shall provide a copy of the annual report to the Commission upon request.

(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 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 by July 15 and January 15 of each calendar year, in accordance with the PS-95 Semi-Annual Leak Report Electronic Filing Requirements using the Commission's online application available on the Commission's website [~~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~~]. 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. All operators shall submit a PS-95 Semi Annual Leak Report every July 15 and January 15, even if there are no pending or repaired leaks during the reporting time period. 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.

(f) The Commission shall retain state records regarding a pipeline incident perpetually. "State record" has the meaning assigned by Texas Government Code §441.180.

This agency hereby certifies that the rules as adopted have been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Issued in Austin, Texas, on November 19, 2024.

Filed with the Office of the Secretary of State on November 19, 2024.

DocuSigned by:
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15494B7DF4CC424...
Christi Craddick, Chairman

DocuSigned by:
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Secretary of the Commission

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Assistant General Counsel
Office of General Counsel
Railroad Commission of Texas

Figure 2: 16 TAC §8.101(b)(2)

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	*10 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

*only for onshore line pipe that can accommodate inspection by means of in-line inspection tools