The Railroad Commission of Texas adopts new §8.209, relating to Distribution Facilities Replacements, with changes to the proposed version published in the September 10, 2010, issue of the *Texas Register* (35 TexReg 8220). On July 6, 2010, the Commission authorized staff to draft a proposed new rule to address mandatory replacement of steel service lines and other facilities in natural gas distribution systems. The Pipeline Safety Division hosted a public workshop on August 18, 2010, with interested persons and stakeholders to discuss the elements of the draft proposed rule. During the workshop, the attendees and Commission staff discussed the draft proposed rule and many of the comments were reflected in the September 10, 2010, proposal.

Following publication of the proposal, the Commission received comments from Atmos Energy Corporation ("Atmos"), CenterPoint Energy Arkla and CenterPoint Energy Entex (jointly "CenterPoint"), CPS Energy ("CPS"), Texas Gas Service ("TGS"), West Texas Gas, Inc. ("WTG"), Continental Industries, Inc. ("Continental"), Dresser Piping Specialties ("Dresser"), R. W. Lyall & Company ("Lyall"), Norton McMurray Manufacturing Company ("NORMAC"), Texas Gas Association ("TGA"), Texas Pipeline Association ("TPA"), and Texas Pipeline Safety Coalition ("TPSC"). None of the comments expressed either complete agreement or complete disagreement with the proposed rule; all offered suggestions for clarifying, adding, or striking provisions of the proposed rule.

CPS expressed appreciation for the revisions the Commission made to proposed §8.209 following the public hearing on August 18, 2010, and opined that the proposed rulemaking will compliment the Commissions' previous rulemaking addressing §8.206 of this title (relating to Risk-Based Leak Survey Program) and the federal government's recently enacted distribution integrity rule (49 CFR Subpart P). The Commission thanks CPS for the comment.

NORMAC pointed out that the product line that it designed, manufactured, and sold included compression fittings of all types, such as adapters, tees, elbows, couplings and risers. The NORMAC fittings are widely accepted and as a result millions have been sold to pipeline operators across the United States. NORMAC commented that several incidents have occurred in Texas where leaks of natural gas have emanated from mechanical fittings, specifically compression type fittings. Other incidents have occurred in other areas of the country. These problems have occurred only in specific areas, while millions upon millions of such fittings outside of these limited areas have shown no sign of trouble. NORMAC contends that several patterns are clearly revealed by an in-depth reading of the entire record of the high profile cases involving mechanical fittings. First, a great deal of mis-information has been presented and accepted as fact by some regulatory bodies. Second, where fittings were not installed appropriately, leaks have occurred. Third, no one has identified any material problem with the fittings themselves. NORMAC greatly appreciated the opportunity to work with Commission staff at the August 18, 2010, workshop in Austin, and urges all regulators to reach out to manufacturers and tap into the wealth of knowledge and experience these companies have to offer. A litany of misunderstandings surrounding compression fittings have surfaced in recent years. Some of those misunderstandings remain today. The Commission neither agrees nor disagrees with these comments.

WTG urged the Commission to adopt a rule for replacement of distribution service lines that is identical to the federal rule and not one that is more stringent. Because WTG also distributes natural gas in Oklahoma, the Commission's proposed rule if adopted, will require WTG to follow two different rules regarding the replacement of steel service lines. Adoption of a statewide rule that corresponds with the federal rule will promote public safety and prevent higher operating costs. WTG is not aware of any studies or relevant evidence to justify a rule that is more stringent than the federal rule. The Commission disagrees in part with WTG's comment, for reasons set out in greater detail in response to TGA's comments. However, the Commission adopts new §8.209 with some clarifying changes that make the Commission's rule more compatible with the federal Distribution Integrity Management Program ("DIMP") rules.

CenterPoint has been analyzing its distribution system and replacing pipe posing unusual risks for many years. For example, CenterPoint has replaced over 240 miles of steel main and 17,000 steel service lines over the past three years. The CenterPoint risk-based program not only considers steel service lines, but also assesses the relative risks of main lines and service lines constructed of plastic, cast iron, and PVC. This analysis is applied to all similar pipe installed in the 488 systems that CenterPoint operates in Texas, without regard to individual system boundaries, in order to insure that the highest risks are addressed regardless of location. CenterPoint continues to refine its risk analysis capabilities and recently implemented a software program named Optimain, which assists in quantifying and identifying the risks existing in its facilities. The Optimain program was used to develop CenterPoint's risk-based leak survey program, which is an integral part of its distribution integrity management plan for its Texas assets. CenterPoint believes that an ideal risk management process prioritizes risk so that those with the greatest loss and the greatest probability of occurring are addressed first, with the lower probability of risks handled in descending order. While quantifying risk is always difficult, the most widely accepted formula for risk quantification is: Rate of occurrence multiplied by the impact of the event (consequences) = risk. The most effective risk management program applies this analysis across the largest universe of assets subject to common management, which insures that the risk equation is applied consistently and is not distorted by artificial limitations on the sets of risks analyzed. This approach is consistent with the International Standard Organization's ("ISO") recommendations for such programs contained in its ISO 13,000 standard on risk management principles and guidelines. The federal Distribution Integrity Management rule also adopts this philosophy and encourages operators to conduct their analysis not only by geographical area, but also by areas with common materials or subject to other environmental factors. See 49 CFR §192.100(c). Finally, it also reflects the legal fact that pipeline safety regulation in Texas is based on the rules of the Railroad Commission and the federal rules, which apply uniformly statewide and do not vary by system identification.

In CenterPoint's view, the Commission's proposed rule seeks to require operators to conduct a risk-based analysis of their distribution systems in order to identify those facilities that pose the highest risk and accelerate their replacement. CenterPoint supports the use of this tool as a method of prioritizing distribution facility replacements, but believes the rule can be improved from its original draft to ensure consistency in the operation of those programs and the replacement of the riskiest facilities on a timely and efficient basis. The new risk-based analysis that the Commission seeks to require under this rule will strengthen the reliability of local distribution systems by introducing an explicit replacement obligation into the integrity management plans already required under the federal rules. However, CenterPoint believes it can be made more consistent both internally and with the federal rule and other applicable standards. The Commission disagrees in part with CenterPoint's comments for reasons set out in greater detail in subsequent paragraphs that address each subsection of the rule. The Commission agrees that some clarification is needed to make the Commission's rule more compatible with the federal DIMP requirements.

The Commission appreciates the comments regarding the rule development process and, in particular, appreciates the participation of the operators in the workshop on August 18, 2010. The Commission agrees that an effective risk management process prioritizes risk so that those with the greatest loss and the greatest probability of occurring are addressed first. The Commission disagrees with WTG's comment that the Commission should adopt only the federal requirements in 49 CFR Part 192, Subpart P-Gas Distribution Pipeline Integrity Management (IM); in fact, the Commission has already adopted these rules by reference in 16 Tex. Admin. Code §8.1 of this title (relating to General Applicability and Standards). The Commission does not agree with all of NORMAC's comments; however, because the Commission is adopting new §8.209 with changes to the proposal, the Commission does agree that some aspects of the proposal require modification or clarification.

TPA and TPSC sought clarification of proposed new §8.209 as it applies to farm taps. The discussions leading to the approval of the proposed rule for publication and comment focused on the operators of local distribution systems. The rule refers to operators of distribution systems or distribution facilities, but without any indication that the Commission was using those terms in any manner other than their traditional and commonly understood meaning, which did not include farm taps. Farm taps have historically never been considered distribution lines by industry or the Commission. According to TPA and TPSC, farm taps generally consist of a riser and regulator directly connected to a transmission or gathering pipeline and providing an aboveground connection for a distribution company or a customer. Sometimes, the farm tap will include a meter. Farm taps have historically been installed in satisfaction of easement provisions negotiated with landowners and are generally located in rural locations. They are not located in densely populated areas and typically do not include any significant length of line extending from the main transmission line. Because most transmission pipelines are steel and connected to the farm tap riser by welded connections, there is no alternative material to be used for these installations and no more secure connection to use in place of present practices. The cost of complying with proposed new

§8.209 will outweigh any safety benefits to be derived from applying this rule to farm taps, and in fact, application of this rule to farm taps could actually result in the lessening of pipeline safety because of the technology issues. Application of the proposed rule to transmission farm taps could result in many operators seeking to disconnected or abandon many farms taps. They were certainly not included in the discussions by Commissioners and Staff prior to the issuance of the proposed rule nor were they included in any of the Commission's evaluations of the fiscal impact of the proposed rule. TPA's and TPSC's concern with the scope of the Commission's proposed rule arises from a recent Pipeline and Hazardous Materials Safety Administration (PHMSA) guidance document relating to its distribution integrity management rule. The guidance document states:

> The vast majority of "farm taps" meet the definition of a distribution line given that they do not meet the criteria to be classified as a gathering line or a transmission line.

TPA and TPSC do not believe the intent of the Commission was to apply the proposed rule to farm taps. Prior to the frequently asked questions ("FAQ") guidance document issued by PHMSA, no gathering or transmission operator would have ever thought or considered that they would be subject this proposed rule. Further, at no time during the development of the rule proposal did the Commission discuss the applicability of the rule to transmission or gathering lines. For these reasons, TPA and TPSC request that the Commission clarify the applicability of the proposed rule to exclude farm taps on transmission and gathering lines, because farm taps on transmission pipelines are subject to the Commission's pipeline integrity rule, §8.101 of this title (relating to Pipeline Integrity Assessment and Management Plans for Natural Gas and Hazardous Liquids Pipelines), which adequately addresses safety and any operational issues. TPA suggested that clarification could easily be provided by simply adding one or two sentences to the preamble of the rule upon adoption. Because this proposed rule imposes requirements beyond those contained in the Federal minimum pipeline safety standards, TPA does not believe that there are any federal prohibitions to the Commission's issuance of the requested clarification of this "above and beyond" rule.

The Commission agrees that farm taps were not expressly discussed in the workshop or in the proposal preamble. However, the Commission disagrees with the assertions by TPA and TPSC that farm taps are part of transmission pipeline integrity management plans pursuant to §8.101 of this title. Transmission pipeline operators have not included farm taps in their integrity management plans, according to those plans that have been reviewed by the Pipeline Safety Division. Given the PHMSA guidance document, it may not be possible for the Commission to exclude farm taps from the DIMP requirements that the Commission administers. However, because TPA and TPSC have clearly taken the position that farm taps are not part of distribution facilities, the Commission will wait to make a final determination on this issue as it pertains to §8.209. ~~Farm taps are not covered under §8.101 of this title because the Commission has always considered farm taps to be part of the distribution facilities operated by a distribution operator. Thus, the Commission considered that such facilities were included in the cost of compliance analysis, even as pipeline operators assumed they were not included because they were not expressly mentioned. Further, given the PHMSA guidance document, the Commission cannot agree with TPA and TPSC that farm taps should be excluded under new §8.209. However, the new rule would not necessarily require that all farms taps be removed or replaced, only that they be included in the risk analysis that operators will conduct for distribution facilities. In addition, operators may be able to bring farm taps under subsection (g) of the rule, which pertains to steel service lines that must remain in service because of specific operational conditions or requirements.~~

mum 2-22-11

Atmos commented that it is not aware of any industry study or finding that suggests joints on below-ground piping should be limited to welding or fusing. While welding and fusing are preferred joining methods, other methods including threaded connections and flanged connections are viable joining methods on below-ground piping. Further, Atmos recognized that, as proposed, subsection (b) appropriately distinguishes between requirements for below-ground connections and above-ground connections. Atmos suggested a minor re-wording of this subsection to clarify the intent, along with the inclusion of standards related to the connection of steel pipe to polyethylene pipe. Atmos proposed that subsection (b) be revised to read as follows: "*(b) When practical, joints on below-ground piping will be made by welding or fusing. Each fitting used to make a non-fused joint on a polyethylene system must meet the requirements of ASTM D2513 for Category 1. Each non-welded joint on a below-ground steel system must meet the requirements of 49 C.F.R. §192.273. When polyethylene pipe is joined to steel pipe the connection must be made with a transition type of fitting that meets the requirements of ASTM D2513 Category 1 for the polyethylene connection and 49 C.F.R. §192.273 for the steel connection.*"

The Commission agrees that subsection (b) should be clarified, but disagrees with the wording suggested by Atmos.

CenterPoint observed that, in addition to the provisions specifying the elements of an operator's risk-based programs, the rule contains a new requirement that distribution operators use welding and fusing to make connections where practical. Where non-fused joints are used on a plastic system, the joint must comply with the ASTM D2513 standard for Category 1 fittings. Non-welded joints on steel systems must meet the requirements of the federal pipeline safety rules provided in 49 CFR §192.273. If applied to all replaced pipe, this rule would conflict with the Commission's rules regarding compression couplings contained in §8.208 of this title, relating to Mandatory Removal and Replacement Program. In order to avoid such a conflict, CenterPoint suggested that this new rule apply only to replacements performed pursuant to the risk-based programs required by the rule. The Commission disagrees with CenterPoint's specific recommendations concerning subsection (b), but agrees that as proposed it conflicts with §8.208 and that the "where practical" standard is too vague to be consistently enforced. The Commission adopts subsection (b) with clarified wording as explained in subsequent paragraphs.

Dresser commented that, as proposed, subsection (b) severely limits the use of mechanical fittings except in special circumstances. Dresser is aware of the incidents in Texas where mechanical fittings were the target of investigations, but concluded that from published data, news articles, and conversations with government regulators that the investigations did not provide any factual information to prove that the fittings were defective or provide a root cause for why the fittings were investigated. In Dresser's opinion, the proposed rule requiring that joints below-ground must be made by welding or fusing is not supported by factual data to indicate that welding or fusing provides a safer joining method than mechanical fittings. The proposed rule implies that mechanical fittings are a practical method for any joint in a piping system where making a joint by welding or fusion is determined to be impractical. Common sense would suggest that if a mechanical fitting can be used to make joints where welding or fusion is impractical, mechanical fittings are an acceptable joining method and the rule should not limit their use. Dresser requested that the Commission remove subsection (b) in its entirety from the rule. Dresser further suggested that if a new rule is needed to improve the reliability associated with the use of mechanical fittings, the rule should address the requirement that pipeline operators follow the manufacturers' installation instructions and application guidelines, similar to federal regulations. The

Commission disagrees with removing subsection (b) from the rule, but adopts the subsection with wording that clarifies the Commission's intent with respect to methods of joining.

NORMAC commented that the proposed requirement that the operator "weld and fuse" is unjustified, resulting in arbitrary and capricious rulemaking. By requiring "weld and fuse," subsection (b) is internally inconsistent and unworkable; therefore subsection (b) should be struck. NORMAC stated that the Commission did not provide justification, reasoning, or rationale for restricting joining methods to "weld and fuse." To impose such a restriction without clearly enunciating the reasons for the decision is both arbitrary and capricious. The Commission has ignored its obligation to formulate rules and policy based on substantial evidence. *See* Tex. Code Ann. §2000.174(2)(E)-(F) [*sic*]. The Commission has provided no reasonable basis for requiring the "weld and fuse" method, and categorically rejecting all other methods. Because the Commission has failed to provide a legitimate reason to promote the use of the "weld and fuse" method of joining pipes over other, equally safe methods, the proposed rule is, by definition, arbitrary and capricious. *See Bullock v. Hewlett-Packard Co.*, 628 S.W.2d 754 (Tx. 1982) (citing *Gerst v. Oak Cliff Savings and Loan Association*, 432 S.W.2d 702 (Tex.1968)). The Commission agrees that subsection (b) should be clarified, but disagrees with NORMAC's characterization of the proposal as "arbitrary and capricious" under the cited legal standards. Tex. Gov't Code, §2001.174, pertains to judicial review of administrative decisions in contested cases using the substantial evidence rule or an undefined scope of review; this part of the Texas Administrative Procedure Act does not apply to rulemaking proceedings.

NORMAC further commented that although there is no evidence of any material problem with the fittings themselves, the question remains why failures have occurred. According to NORMAC, the answer is simple: failures have been a result of inadequate installation or application practices. Failures have occurred only in limited, specific portions of Texas or the United States. Installations elsewhere remain safe and sound. In areas where these practices were performed properly, mechanical fittings have served successfully. Where poor, rushed or sloppy practices were employed, the results have been disastrous. The Plastic Pipe Database Committee published an updated status report which finds that leaks are commonly due to "installation error": "The data indicate an elevated number of leaks associated with new pipe or appurtenance installations occur within the first three years after being put into service. The data also indicate a decrease in the number of these leaks since the implementation of Operator Qualification requirements in 2002. However, leaks are still occurring in this time period at an elevated frequency. Operators have reported the cause of these leaks as installation error which could be the result of inadequate procedures, training, or implementation of the procedures. In light of the data collected, it is suggested that operators remain vigilant in their efforts to maintain their operator qualification programs, installation procedure reviews and inspection efforts to assure the integrity of their systems." Whatever the time frame, appurtenances including both mechanical fittings and "weld and fuse" fittings that are properly used and installed provide long-term, safe service. Therefore, installations of both types of devices should be allowed to be installed by qualified personnel. No study has shown any deficiency with properly installed and properly applied mechanical fittings. There is no evidence of safety advantages of proper installations of "weld and fuse" over joints properly made with mechanical fittings. When done properly, each joining method is viable and secure. Therefore, each should be afforded equal standing by the Commission. The Commission agrees with NORMAC that there has been no specific determination that mechanical fittings are inherently unsafe. However, by NORMAC's own argument, such devices may fail when they are improperly installed, and such devices have been implicated in at least two incidents in Texas.

NORMAC further commented that by requiring "weld and fuse," proposed subsection (b) is internally inconsistent and unworkable. Given that the Commission's mandate appears to be grounded in safety concerns, the only logical reason for requiring "weld and fuse," rather than mechanical fittings, as the primary means for joining is that "weld and fuse" is believed to be a safer method. Were this true, mechanical fittings would be completely banned. However, the proposed rule allows mechanical fittings to be used in situations in which the "weld and fuse" method is not "practical." If mechanical fittings are safe for any use, then they are safe for every use for which they are intended. Additionally, there is no consistency in requiring the use of the "weld and fuse" method underground, while allowing any joining method above ground on the same service line. Subsection (b) of the proposed rule allows limited use of mechanical fittings "where practical." The words "where practical" are vague, overly subjective, and thus unenforceable. How is an engineer at a gas company to determine if a joint made with a mechanical fitting is more or less "practical" than one made by "weld and fuse"? What are the ramifications if, after a mechanical fitting has been used, the operator and the Commission disagree as to whether its use was practical? Nor is it clear exactly where and when the requirements of subsection (b) will apply. Further, NORMAC compared proposed subsection (b) to Commission rule §8.208 of this title, (relating to Mandatory Removal and Replacement Program). That rule makes no mention of "weld and fuse" and allows mechanical joints as long as they meet the appropriate ASTM D2513 Category and comply with applicable regulations. If mechanical fittings are allowed by one rule, they ought to be allowed by all applicable rules. This inconsistency is not only illogical; it is confusing and impractical to follow and to enforce. NORMAC's first recommendation is for the Commission to delete subsection (b); if not, the Commission should modify the language to follow the changes made to proposed subsections (c), (d), (f), and (g) just prior to the August 30, 2010, Commission meeting so as to clarify that the prescriptive actions in (b) apply only to operators who find that steel service lines pose the highest risk. The Commission agrees that the language "where practical" is vague and subjective and therefore difficult to enforce consistently. The Commission disagrees that subsection (b) should be removed from the rule and disagrees that it should apply only to operators that find that steel service lines pose the highest risk. The Commission adopts subsection (b) with clarifying language explained in subsequent paragraphs.

Continental commented that the proposed requirement that operators "weld and fuse" is unjustified, and suggested rewriting proposed subsection (b) so that there is no preference given between approved fittings and joining methods. Although aware of recent issues with compression fittings in Texas, Continental stated that the bias against all mechanical fittings is unjustified. Other mechanical fittings that may be affected by the proposed rule include; factory made transition fittings, risers, mechanical saddles, and stab type fittings. Continental expressed concern that proposed subsection (b) will result in the creation of baseless and unwarranted prejudice against mechanical fittings resulting in reduced competition and higher costs to the ratepayer. Furthermore, the safety of gas distribution systems will be compromised if gas distribution operators do not include mechanical fittings in evaluations of system design and maintenance. Mechanical fittings offer the highest possible joint integrity in certain situations with regard to environment, materials, operator skill level and training. The language of the proposed rule puts the operator in a defensive position to justify why it is not practical to use fusion instead of using mechanical fittings that meet the requirements of ASTM D2513 Category 1, and why it is not practical to weld instead of using mechanical fittings that meet the requirements of 49 CFR §192.273. The determination of what is practical will be highly subjective and difficult to enforce in a standardized fashion. Continental offered the following substitute language for subsection (b):

(b) Each operator will 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 axial pullout per 49 CFR 192.273.

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

Lyall's comments focused on the August 18, 2010, workshop, at which it was expressed that the intent of subsection (b) of this rule was not to establish a new imperative regarding the use of approved component types and joining methods on plastic or steel piping but to establish and clarify that a joint on either piping material must be made to be at least as strong as the pipe in the longitudinal (axial) direction. Lyall offered a summary of the technical provisions governing joints on plastic and steel pipe. For plastic joints, it is clear and well established in code and practice that sound joint integrity is accomplished through cooperation between material and method that is achieved through design and validation for both heat fusion and mechanical joints. The qualification of procedures for joining using heat fusion or mechanical means is the same in respect to requirements for axial strength and pull out resistance. Both mechanical joints and heat fusion joints are approved today for new installation and repair of service lines. For steel joints, the pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading. Again it is well understood that sound joint integrity is accomplished through cooperation between material and method that is achieved through design and validation for both welded steel joints and mechanical steel joints. A mechanical joint must provide pullout resistance to anticipated external and internal loading. It is these standards for both plastic and steel joints that was expressed when it was stated, during the workshop, that it was not the intent of §8.209(b) to change what was already currently approved in regard to pipe joining. There were many changes to subsection (b) from initial draft to the present. Each change sought to bring more clarity to the requirement that a joint provide longitudinal pull out resistance and provide strength at least as strong as the pipe in the axial direction. While likely unintended, the language of the proposed rule puts the operator in a defensive position to justify why it is not practical to use fusion before using a Category 1 mechanical fitting which, as discussed above, is already approved. It will also cause the operator to justify why it is not "practical" to use a weld joint before an approved mechanical method is used. Determination of what is "practical" will be highly subjective and difficult at best to manage in a standardized fashion. An operator will be faced with deciding what is "practical" instead of what is appropriate. What is appropriate is already established as a joint that provides a seal and resistance to pull out in the axial direction. Lyall submitted the following language as a replacement for the language in section (b) of the proposed rule, identical to that offered by Continental:

(b) Each operator will 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 axial pullout per 49 CFR 192.273.

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

Lyall offered the replacement language as a reasonable way to satisfy the intent of the rule, because it is in line with what is in federal code and in line with specifications referenced by federal code today, and does not introduce unwarranted preferences except that only fusing and Category 1 mechanical fittings can be used for in line plastic joints, and only welded or axially restrained fittings can be used for in line steel joints. The Commission agrees that the "where practical" standard is vague and too subjective to be consistently enforced, and that as proposed, subsection (b) is inconsistent with §8.208. The Commission adopts subsection (b) with the wording offered by Continental and Lyall to clarify the standards for joints on below-ground piping, with one change. In place of the word "axial pullout," the Commission is using "longitudinal pullout or thrust forces" because that terminology is consistent with 49 CFR §192.273.

Regarding proposed subsection (c), Atmos expressed concern that the timing of the proposed submission - no later than March 1, 2011 - will not allow an operator to fully utilize its DIMP efforts because the March 1, 2011, date precedes the DIMP implementation time line. Therefore, in order to more closely align the rule with the Commission's stated goal of utilizing the DIMP efforts, Atmos suggested that the subsection (c) filing date be changed to August 1, 2011, to coincide with the DIMP implementation time line.

CPS urged the Commission modify the rule's implementation deadline to follow the implementation of the DIMP rule in 49 CFR Subpart P. Subsection (d) of the Commission's proposed rule directs each operator to collect data under itsDIMP, but the implementation requirement of the DIMP is not until August 2011. CPS suggested an implementation date of January 1, 2012, for the submission of each operator's written procedures for implementing the requirements of this section, following the completion of the DIMP in August 2011. Delaying implementation of §8.209 until January 1, 2012, would allow the Commission to make several modifications to the proposed rule that would provide the Commission with more useful information relative to the performance of steel infrastructure between and within system IDs and time to gather and study the data provided.

TGA pointed out that, effective February 12, 2010, 49 CFR Part 192 was revised to require that gas distribution operators develop and implement a DIMP no later than August 2, 2011. As noted in the preamble to the Commission's proposed rule, the risk-based programs that the proposed rule requires Texas gas distribution operators to implement are to " . . . be developed in conjunction with the recently adopted . . ." federal regulations. The preamble also notes that the Commission estimates that it will take operators at least a year to develop the risk model required by the proposed rule. TGA commented that despite the Commission's acknowledgment that operators will need at least a year to develop the risk model portion of the risk-based program, the Commission failed to take that fact into consideration by requiring that written procedures be submitted to the Commission on March 1, 2011, for review and approval. Furthermore, a March 1, 2011, filing date will necessitate that operators develop their risk-based programs ahead of the development of their federally mandated DIMP programs rather than in conjunction with the development of those programs. Because the Commission's proposed risk-based programs should necessarily complement the programs operators are developing and implementing in response to the federal regulations, TGA concluded that it is reasonable to revise the filing date to August 1, 2011.

WTG concurred with the written comments of TGA, adopted its comments by reference, and urged the Commission to establish an appropriate date for submission of written procedures make proposed §8.209 effective August 1, 2011, instead of March 1, 2011. WTG needs the additional time to more effectively and economically adopt a risk-based integrity management plan for proposed §8.209 to coincide with DIMP rules.

TGS commented that the filing date for submission of the written procedures required by §8.209(c) be changed from March 1, 2011, to May 1, 2011. The rule provides that the Commission's program will work in conjunction with the federal DIMP. A May 1, 2011, submission deadline will encourage operators to focus on the preparation of a single plan that meets both the Commission's and the federal government's requirements. Such a submission will result in a more effective and efficient implementation of both sets of rules by providing time for preparation of the most robust plan possible, minimize potentially duplicative efforts, and assure that the Commission receives submissions that are consistent with both its own rules and those of the federal government.

CenterPoint observed that the Commission's proposed rule apparently seeks to impose a stronger replacement mandate on Texas LDC's than the current federal DIMP rules. While subsection (a) states that the new programs are to work in conjunction with operators' DIMP programs, as proposed the rule also requires operators to submit their programs by March 1, 2011, even though the distribution integrity management plans required by the federal DIMP rules are not required to be completed until August 1, 2011. This will require operators to potentially prepare two separate programs with the attendant risks of conflict and waste of resources. CenterPoint suggested that the deadline for the submission of the state programs be changed to the August 1, 2011, so that it is coextensive with the effectiveness of the federal rule.

The Commission agrees with the comments that imposition of a March 1, 2011, deadline for the filing of operators' written procedures for implementing the requirements of this section may not provide effective and efficient implementation of plans that meet the both the Commission's and the federal government's requirements. While the Commission seeks to ensure that operators are well on the way to implementing their risk management programs as mandated by the federal rules, the Commission also recognizes that imposing a compliance deadline that is only five months earlier than that for the federal program may thwart that goal. Therefore the Commission amends subsection (c) as adopted to amend the compliance date to August 1, 2011, to match the federal DIMP deadline.

Atmos requested clarification of the provision in subsection (c) requiring that written procedures to implement §8.209 must be submitted to the Pipeline Safety Division for review and approval. Atmos is uncertain whether the intent is to require the submission of written procedures that an operator will, in turn, use to develop relative risks and associated consequences or if the written procedures are intended to reflect the approach the operator intends to take based upon an already completed risk analysis. The Commission anticipates that the operators' initial filings would consist of written procedures for identifying the factors to be used and the proposed weighting or approach an operator would use. The Commission expects that the actual risk analysis would take another year to complete.

CenterPoint had additional comments on subsection (c) with respect to the requirement that each operator develop a risk-based program to determine the relative risks and their associated consequences within each pipeline system or segment. In CenterPoint's view, the best risk management programs examine risk across as broad a universe of facilities as possible in order to insure the statistical validity of the analysis. As previously mentioned, CenterPoint analyzes its system through its Optimain program, which applies the same risk factor elements and consequence analysis consistently across its distribution systems in Texas. CenterPoint commented that the current draft of the rule would require an operator to conduct separate risk-based analyses for each of the operator's distribution systems and identify segments within those systems for replacements. Many of CenterPoint's systems consist of only a few service lines while others, such as Houston, contain thousands. Requiring separate risk-based analyses for each of these systems would defeat the purpose of the rule, which is to consistently identify the highest risk pipe for replacement and another action. CenterPoint suggested that the rule be changed by allowing operators to apply their risk-based analysis jointly across all of their distribution systems in Texas and not severally.

The Commission disagrees with CenterPoint's description of the risk program development process. The Commission does not intend for each operator to develop a separate risk model for each system ID. The Commission's intent is that each operator develop a single risk based program that will be implemented across its entire distribution operations. In developing such a risk-based program, the operator is to evaluate its pipeline systems by analyzing data collected for each system or segment, as identified, to provide a clear picture of the particular risks within each of the operator's distribution systems.

In addition, CenterPoint asserted that, while the proposed rule appropriately assigns to the operator the responsibility of identifying the highest risks on its system, subsection (c) creates a special replacement regime in cases where steel service lines are determined to be the greatest risk. Specifically it requires operators to calculate a leak repair rate for steel service lines by dividing the number of leaks on such lines by the number of other types of leaks occurring in a particular system. If this calculation yields a percentage greater than 25%, the operator must replace all service lines in the system by June 30, 2013. Systems with leak rates of between 5% and 25% must replace 10% of the steel service lines in the system per year. CenterPoint commented that this prescriptive program is inconsistent with good risk management practices in several ways. First, it assumes steel service lines pose such an unusual risk that they must be subject to a special program. In fact, CenterPoint observed, steel lines generally are more resistant to third-party damage and, if properly coated or protected with cathodic protection, are not subject to a significantly higher corrosion risk. When leaks occur on steel systems, the source is a fitting in the vast majority of cases. The Commission has already addressed this risk in its compression coupling rule codified at §8.208 of this title (relating to Mandatory Removal and Replacement Program). The Commission disagrees in part with this comment. The Commission recognizes that steel service lines may not be the riskiest part of an operator's system. However, the Commission has adopted modifications to the calculation of the leak repair rate for steel service lines in subsection (d) that makes a more appropriate comparison of leaks on steel service lines to the total number of steel service lines rather than to the total number leaks on the system. In turn, modifying the formula required a modification of the percentage brackets for Priority 1 and Priority 2 categories.

Atmos commented that subsection (d) does not make clear whether the Commission intends for an operator to use "raw" leak data from PS-95 or if operators will have the ability to adjust PS-95 leak data to remove leaks related to assets that have been retired or replaced. If assets have been removed from service, it is logical that leaks related to those assets should be excluded from future risk analysis scenarios. If not excluded, consideration of leaks that occurred on retired or replaced assets would continue to highlight areas where facilities have already been retired or replaced as areas where facilities need to be replaced. This creates a circular, unintended result in the process. This can be easily remedied by removing leak data from the analysis that is associated with facilities that have been retired or replaced. The Commission agrees with Atmos and has clarified the wording in subsection (d) to allow operators to remove data for those facilities that have been retired or replaced facilities.

CPS encouraged the Commission to revise the formula in subsection (d) because it does not provide a reasonable basis of comparison of performance of steel infrastructure between System IDs or segments within a system. The formula or ratio of leaks repaired on steel service lines divided by the total number of leaks repaired does not provide an accurate depiction of relative risk or performance and could lead to an inappropriate allocation of resources to replace steel service lines in segments that have a low overall leak rate as a percent of steel service lines. In the penultimate sentence in subsection (d), the rule requires that the leak repair rate for steel service lines is determined by dividing the number of leaks repaired on steel service lines by the number of all repaired leaks. CPS recommended that the more useful denominator is the total number of steel services in the system ID, not all repaired leaks. CPS's proposed revision is, "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 compared to all steel services within the system ID." In the last sentence in subsection (d), CPS suggested that the total number of steel service lines is a more useful denominator. The sentence states, "*The leak rate for below-ground steel service lines is determined by dividing the number of below-*

ground leaks repaired on steel service lines (excluding third-party leaks) by the total number of leaks repair [sic] on the pipeline system." The preferred relationship again is between steel services, and the denominator should be the total number of steel service lines. CPS proposed the following revision: "The leak repair rate for below-ground steel service lines is determined by dividing the number of below-ground leaks repaired on steel service lines (excluding third-party leaks) by the total number of steel services on the pipeline system."

TGS also commented that the formula in subsection (d) does not actually provide for the best method to conduct this analysis. The Gas Piping Technology Committee's (GPTC) guide to DIMP was developed using a task group with diverse and varied members. The task group, in addition to members of the GPTC, included persons representing segments of the gas pipeline industry not currently active on the GPTC, such as industry associations, small gas operators, state pipeline safety program directors, public representatives, and Pipeline and Hazardous Materials Safety Administration (PHMSA) personnel. The GPTC's guide recommends a risk evaluation method that states, "one approach to risk evaluation is to group facilities by common traits and problems, which allows each group to be risk-ranked as a unit. The risk ranking is an analysis that assigns a relative risk value and may result in a recommendation for action." The guide also recommends in the federal rule, paragraph 5.4 (a) (4), that "the operator should evaluate problem trends. Stable or improving trends may require no further action," and suggests a review of leaks caused by excavation measured by miles of main or services per number of services. Such an approach would better allow an operator to determine and address potential trends. TGS suggested that subsection (d) be amended to reflect an "apples to apples" calculation consistent with the GPTC guide for purposes of calculating the leak repair rate for below-ground steel services, by dividing the number of below-ground leaks repaired on steel service lines (excluding third-party leaks) by the total number of steel services on each system. As part of the annual filing required by subsection (i), a company would be required to submit the number of steel services by system. The total of these steel services would equal the number of steel services reported on the Annual Gas Distribution Report, form PHMSA F 7100.1-1. This will provide the Commission with the data necessary to review an operator's leak analysis. TGS believes that modifying the formula, in conjunction with using a conservative percentage cutoff in subsection (f), will result in more accurate identification of pipeline integrity risk, more consistent with the DIMP guideline, and, as a result, increased pipeline safety.

CenterPoint commented that, if the Commission still deems the prescriptive program to be necessary, the leak calculation rate should be based on leaks per number of steel service lines and not the number of leaks in a system. The former calculation is a more accurate measure of a system's performance while the latter can distort the true picture of a system's risks and mis-allocate scarce resources. If the Commission agrees with this recommendation and adopts a leak rate calculation based on the number of steel service lines, CenterPoint believes that a 7.5% threshold should be established for Priority 1 systems and a 5% threshold used for Priority 2 systems. This would direct the operator to those few systems that may require attention and potential replacement. In addition, an exception should be carved out for those steel lines that must remain due to special operational conditions such as state or local rules for highway crossings and the use of highway right of way. The Commission agrees with the comments that the leak calculation rate should be based on leaks per number of steel service lines and not the number of leaks in a system. The Commission also agrees that the calculation should exclude those facilities that have been retired or replaced. The Commission adopts subsection (d) with clarifying language regarding the methodology for performing the leak calculation and for using the data from Commission Form PS-95. The exception for steel service lines that must remain in service for special operational conditions or requirements remains in subsection (g); the deadlines that were set out in paragraphs (1), (2), and (3) of the proposed rule have been moved to subsection (f).

TGS suggested that subsection (e) be modified to clarify that the risk ranking is intended to identify segments for which replacement is necessary by adding the word "necessary" in the last sentence of the subsection. The Commission agrees that the subsection should be clarified, and has added the recommended clarifying language. In addition, the Commission has modified the subsection by placing some of the requirements in a slightly different sequence, and making grammatical corrections.

TGA commented that the prescriptive provisions of subsections (f) and (g) are inconsistent with a risk-based program and should be deleted. The general comments that accompanied adoption of the DIMP regulations state that the purpose of a risk-based safety program is to require that natural gas distribution operators "...evaluate their pipelines to identify the risks important to their circumstances and take appropriate actions to address those risks." The comments also note that "...incidents are most often caused by a combination of circumstances that represent risks for the pipeline involved, but may not affect other pipelines." TGA concludes that it is "...not practical to create additional prescriptive requirements to address these pipeline specific risks."

TGA stated that the Commission has done an exceptional job of enforcing the state and federal pipeline regulations that are meant to help assure public safety. In fact, the Commission's pipeline integrity rule, as well as its risk-based leak survey rule, were trend-setters for other state and federal regulators. However, including the prescriptive provisions in subsections (f) and (g) are not consistent with the overarching purpose of a risk-based program that requires an operator to evaluate its distribution system for risk and then enact a replacement program that results in the reduction of that system specific risk. In addition, the implementation of the prescriptive provisions of the proposed rule could pose a financial hardship on certain of the municipally operated distribution systems. The prescriptive provisions have the potential to cause municipal operators to incur additional costs to develop the required risk-based program. To the extent that the Commission can adopt a rule that will allow a municipal operator to utilize the same risk-based program for purposes of complying with both the Commission's rule as well as the federal DIMP, the overall cost to the operator will be reduced.

The Commission disagrees with TGA that the prescriptive elements of the rule should be removed. The Commission recognizes that steel service lines may not pose the greatest risk on some systems. For those systems on which steel service lines are the highest risk, the Commission has imposed a more stringent safety requirement. The Commission also disagrees with the comment that implementation of the prescriptive provisions of the rule could pose a financial hardship on certain of the municipally operated distribution systems. The Commission recognizes that financial issues can be daunting for municipal governments, yet risk is not distributed according to the financial resources of the operator. Municipal operators are not required to come before the Railroad Commission to seek rate relief for capital improvements to their distribution systems.

CPS recommended a revision to §8.209(f)(1), which identifies "a segment with a steel service line leak rate of 25% or greater" as a Priority 1 segment. CPS suggested replacing the preceding "25% or greater" language with "7.5% or greater on an annualized basis or 20% over three years." Based on an analysis conducted by several large Texas LDCs, the recommended annualized leak rate based on the new formula effectively targets the worst performing systems and/or segments. TGS also recommended the same change to subsection (f)(1).

CPS recommended eliminating §8.209(f)(2), because §8.209(h) states that "all replacement programs require a minimum annual replacement of 5% of the segments identified for replacement." This program will be continuously evolving, and the worst performing segments will always escalate up to Priority 1 status if they worsen. TGS recommended amending subsection (f)(2) to read: "a segment with a steel service line rate of 7.5 % or greater but less than 5% is a Priority 2 segment." TGS also recommended that subsection (f)(3) be changed to read: "*a segment with a steel service line rate of less than 5% is a Priority 3 segment. An operator is not required to remove or replace any Priority 3 segment; however, upon discovery of a leak on a Priority 3 segment, the operator must remove or replace rather than repair, except as outlined in subsection (g) of this section.*"

The Commission agrees with the comments that suggest revisions to the determination of risk categories Priority 1 and Priority 2. Because of the change in the formula for calculating the leak rate for steel service lines, the percentage brackets for those categories should be reduced. The Commission adopts subsection (f) with amended percentages for the Priority 1 and Priority 2 categories as follows: a segment with an annualized steel service line leak rate of 7.5% or greater is a Priority 1 segment; a segment with an annualized steel service line leak rate of 5% or greater but less than 7.5% is a Priority 2 segment. The definition of a Priority 3 segment remains unchanged at a leak rate of less than 5%; however, the Commission has clarified the calculation to specify an annualized rate. In addition, the Commission has included in subsection (f)(1), (2), and (3) the replacement deadlines that were proposed in subsection (g)(1), (2), and (3).

Atmos commented that rather than establishing a firm deadline of June 30, 2013, for replacement of Priority 1 steel service lines, operators should be provided a firm time frame for the Priority 1 replacement completion. In other words, if an operator submits written procedures per subsection (c) on

March 1, 2011, and the Safety Division reviews the written procedures within its specified 90 days time frame and then requests revision by the operator and re-submission of written procedures, the resulting replacement time frame for Priority 1 steel service lines may be significantly less than two years. To provide an operator with the intended two year replacement window, Atmos proposes that subsection (g)(1) be revised to provide: "*For Priority 1 segments, an operator must complete the removal or replacement of steel service lines within twenty-four months following the date that the Pipeline Safety Division approves the operator's written procedure required under subsection (c).*" The Commission disagrees with Atmos's comment regarding extension of the June 30, 2013, deadline. The Commission's intent was not to provide a two-year window for replacement, it was to establish a deadline for replacement of steel service lines.

With respect to subsection (g)(2), concerning Priority 2 steel service lines, which must be replaced at a pace of 10% of the original inventory per year, Atmos commented that an operator should not be required to direct resources to replace Priority 2 steel service lines when there are still higher risk Priority 1 steel service lines in the ground. Therefore, Atmos proposes that subsection (g)(2) be revised as follows: "*Upon completion of the Priority 1 segment removal or replacement, an operator must remove or replace no less than 10% of the original inventory of Priority 2 segments per year.*" With respect to the deployment of resources toward Priority 2 steel service lines while Priority 1 steel service lines are still in place, the Commission disagrees; such a requirement would allow a more efficient deployment of work crews in one town or neighborhood. After June 30, 2013, there should not be any Priority 1 steel service lines in place. Operators also may address this issue in the proposed work plans required to be filed pursuant to subsection (i).

TGS recommended amending the language in subsection (i)(2) to add a reference to using the PHMSA Form F 7100.1-1 as the source of the number of steel service lines. The Commission agrees in part with this suggestion because the form is already filed at the Commission and is readily accessible. The Commission has added this clarifying reference to the adopted rule, but not in subsection (i)(2); the reference has been added as part of the leak rate calculation in subsection (d). In addition, the Commission has added clarifying language in subsection (i)(2) regarding the annual filing required from operators.

With respect to §8.209(j), TGA commented that the Commission's financial analysis of the potential costs that operators will incur in developing and implementing the risk-based program is set out in the preamble of the proposed rule. Clearly, cost is a significant factor whenever an operator undertakes the replacement of distribution system infrastructure and the TGA commends the Commission for considering this issue and including the accounting treatment provisions contained in subsection (j).

TGS recommended changes to in subsection (j)(1)(A) and (j)(1)(C), and the addition of language in (j)(1)(E), that would provide for possible recovery and amortization of the unamortized balance of the designated regulatory asset accounts consistent with proposed subsection (j)(1)(D), as written.

CenterPoint commented that safety has always been the highest priority of both the Commission and distribution system operators. As a result, local distribution companies in Texas have implemented a web of operations and maintenance programs and practices to fulfill their service obligations with the highest degree of safety and reliability. The Commission has historically recognized the importance of these programs by authorizing the recovery of pipeline safety- related costs in the rate base and cost of service components of a utility's rates. Thus, it is appropriate that the proposed rule sets an accounting framework for the potential recovery of the costs of the new risk-based safety programs. Subsection (j) will allow LDCs to establish regulatory asset and capital accounts to capture the expenses related to this new program and adjust those balances as they are recovered in rates. CenterPoint believes this accounting treatment is the correct method to insure that these costs are adequately reflected in a utility's books and supports this portion of the rule.

TGS recommended adding the word "replacement" in subsection (j)(1)(A). The Commission disagrees; the word "installation" includes "replacement." TGS recommended adding language in subsection (j)(1)(C) that would allow a utility operator to record a return on unamortized balance using a pretax cost of capital approved for ratemaking purposes by the Commission or other regulatory body. TGS also recommended a new subsection (j)(1)(E) that would permit a utility operator to recover a return on and amortization of the unamortized balance of the designated regulatory asset accounts through base rates or a separate rider established in a subsequent Statement of Intent filing or other rate adjustment mechanism.

The Commission disagrees with these comments and declines to make the recommended changes. Current regulatory accounting practices already permit a utility to create sub-accounts and to request special rate treatment for specific capital investments. In fact, as proposed, subsection (j) contained nothing new or different with respect to traditional ratemaking principles. Incorporating the suggested changes might it appear that the Commission is approving particular accounting methodologies, treatments, or even retroactive ratemaking, which would not be consistent with Texas Utilities Code, Chapter 104, or the Commission's rules in Chapter 7 of this title (relating to Gas Services Division). Certainly, TGS may make such requests in a Statement of Intent to increase rates, and, as always, would bear the burden of proving that such accounting practices and rate treatment are necessary and reasonable. The Commission adopts subsection (j) without changes to the proposal.

The Commission adopts new §8.209, relating to Distribution Facilities Replacements, with clarifying changes as explained in previous paragraphs.

Subsection (a) sets out the applicability and purpose of the new rule. This section applies to each operator of a gas distribution system that is subject to the requirements of 49 CFR Part 192, and 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. The Commission has removed the proposed January 1, 2011, effective date of the new rule; the rule will become effective 20 days from the date of filing.

Subsection (b) prescribes the requirements for making joints on below-ground piping. Joints on steel pipe must be welded or designed and installed to resist longitudinal pullout or thrust forces per 49 CFR §192.273. Joints on plastic pipe must be fused or designed and installed to resist longitudinal pullout or thrust forces per ASTM D2513-Category 1.

Subsection (c) provides that no later than August 1, 2011, operators must submit to the Pipeline Safety Division for review and approval their 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. Operators that determine that steel service lines are the greatest risk must conduct the steel service line leak repair analysis set forth in subsection (d) and use the prescriptive model in subsection (f) for the replacement of those steel service lines. Within 90 days after receipt of an operator's written procedures, the Pipeline Safety Division must either notify the operator of the acceptance of the plan or complete an evaluation of the plan to determine compliance with this section. If the Pipeline Safety Division determines that an operator's procedures do not comply with the requirements of this section, the operator must modify its procedures as directed by the Pipeline Safety Division.

Subsection (d) directs that 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 Commission clarified the formula for calculating the leak repair rate for below-ground steel service lines to state that it is determined by dividing the annualized number of below-ground leaks repaired on steel service lines (excluding third-party leaks and leaks on steel service lines removed or replaced under this section) by the total number of steel service lines as reported on PHMSA Form F 7100.1-1, the Gas Distribution System Annual Report. Until the Commission has collected three full calendar years of data submitted on the PS-95, operators may use two calendar years of data to perform the steel service line leak repair analysis. Once the Commission has collected three full calendar years of data submitted on the PS-95, each operator that determines that steel service lines are the greatest risk must conduct the steel service line leak repair analysis using the most recent three calendar years of data reported to the Commission on Form PS-95.

Subsection (e) requires each operator to 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. Operator should include the following five factors in developing its risk analysis: 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; 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; 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; 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 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.

Subsection (f) applies to operators that determine under subsection (c) that steel service lines are the greatest risk. Based on the results of the steel service line leak repair analysis under subsection (d), 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). A segment with an annualized steel service line leak rate of 7.5% or greater is a Priority 1 segment and an operator must complete the removal or replacement by June 30, 2013. A segment with an annualized steel service line leak rate of 5% or greater but less than 7.5% is a Priority 2 segment and an operator must remove or replace no less than 10% of the original inventory per year. A segment with an annualized steel service line leak rate of less than 5% is a Priority 3 segment. An operator is not required to remove or replace any Priority 3 segments; however, upon discovery of a leak on a Priority 3 segment, the operator must remove or replace rather than repair those lines except as outlined in subsection (g).

Subsection (g) provides that 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. On adoption, the Commission moved the deadlines for removing and replacing pipeline segments or facilities to subsection (f) of the rule.

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

Subsection (i) requires that, in conjunction with the filing of the pipeline safety user fee pursuant to §8.201 of this title (relating to Pipeline Safety Program Fees) and no later than March 15 of each year, each operator file with the Pipeline Safety Division by System ID, a list of the steel service line or other distribution facilities replaced during the prior calendar year; and the operator's proposed revisions to its risk-based program and proposed work plan for removal or replacement for the current calendar year, the implementation of which is subject to review and amendment by the Pipeline Safety Division. Each operator must notify the Pipeline Safety Division of any revisions to the proposed work plan and, if requested, provide justification for such revision. Within 45 days after receipt of an operator's proposed revisions to its risk-based plan and work plan, the Pipeline Safety Division will notify the operator either of the acceptance of the risk-based program and work plan or of the necessary modifications to the risk-based program and work plan.

Subsection (j) authorizes each operator of a gas distribution system that is subject to the requirements of §7.310 of this title (relating to System of Accounts), to 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. The subsection provides that the operator may 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; 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; record interest on the balance in the designated distribution facility replacement accounts based on the pretax cost of capital last approved for the utility by the Commission; 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 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. This subsection does not render any final determination of the reasonableness or necessity of any investment or expense.

The Commission adopts the new rule 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 as set forth in §81.051, 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; 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 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.*

Texas Natural Resources Code, §§81.051 and 81.052; Texas Utilities Code, §§121.201-121.211; and 49 United States Code Annotated, §§60101, *et seq.*, are affected by the new rule.

Statutory authority: Texas Natural Resources Code, §§81.051 and 81.052; Texas Utilities Code, §§121.201-121.211; and 49 United States Code Annotated, §§60101, *et seq.*

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

§8.209. Distribution Facilities Replacements.

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

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

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

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

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

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

Commission on Form PS-95.

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

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

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

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

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

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

similar activities or conditions.

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

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

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

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

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

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

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

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

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

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

(1) The operator may:

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

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

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

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

(E) use the presumption set forth in §7.503 of this title (relating to Evidentiary

Treatment of Uncontroverted Books and Records of Gas Utilities) with respect to investment and expense incurred by a gas utility for distribution facilities replacement made pursuant to this section.

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

This agency hereby certifies that the sections 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 February 22, 2011.

Filed with the Office of the Secretary of State on February 22, 2011.

RAILROAD COMMISSION OF TEXAS

Elizabeth Ames Jones

Elizabeth A. Jones, Chairman

Michael L. Williams, Commissioner

David Porter

David Porter, Commissioner

ATTEST:

Kathy Way

Secretary of the Commission

Mary Ross McDonald

Mary Ross McDonald
Managing Director, Special Counsel
Office of General Counsel
Railroad Commission of Texas