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Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Final Rule

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket No. PHMSA–RSPA–2004–19854; Amdt. 192–113]

RIN 2137–AE15

Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Final rule.

SUMMARY: PHMSA is amending the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement integrity management (IM) programs. The purpose of these programs is to enhance safety by identifying and reducing pipeline integrity risks. The IM programs required by this rule are similar to those required for gas transmission pipelines, but tailored to reflect the differences in and among distribution pipelines. Based on the required risk assessments and enhanced controls, the rule also allows for risk-based adjustment of prescribed intervals for leak detection surveys and other fixed-interval requirements in the agency's existing regulations for gas distribution pipelines. To further minimize regulatory burdens, the rule establishes simpler requirements for master meter and small liquefied petroleum gas (LPG) operators, reflecting the relatively lower risk of these small pipelines.

In accordance with Federal law, the rule also requires operators to install excess flow valves on new and replaced residential service lines, subject to feasibility criteria outlined in the rule.

This final rule addresses statutory mandates and recommendations from the DOT's Office of the Inspector General (OIG) and stakeholder groups.

DATES: *Effective Date:* This Final Rule takes effect February 2, 2010.

Comment Date: Interested persons are invited to submit comment on the provisions for reporting failures of compression couplings by January 4, 2010. At the end of the comment period, we will publish a document modifying these provisions or a document stating that the provisions will remain unchanged.

ADDRESSES: Comments limited to the provisions on reporting failures of mechanical couplings should reference Docket No. PHMSA–RSPA–2004–19854 and may be submitted in the following ways:

- *E-Gov Web site: http://www.regulations.gov.* This site allows the public to enter comments on any **Federal Register** notice issued by any agency.
- *Fax:* 1–202–493–2251.
- *Mail:* DOT Docket Operations Facility (M–30), U.S. Department of Transportation, West Building, 1200 New Jersey Avenue, SE., Washington, DC 20590.
- *Hand Delivery:* DOT Docket Operations Facility, U.S. Department of Transportation, West Building, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Instructions: In the E-Gov Web site: *http://www.regulations.gov,* under ''Search Documents'' select ''Pipeline and Hazardous Materials Safety Administration.'' Next, select ''Notices,'' and then click ''Submit.'' Select this rulemaking by clicking on the docket number listed above. Submit your comment by clicking the yellow bubble in the right column then following the instructions.

Identify docket number PHMSA–RSPA–2004–19854 at the beginning of your comments. For comments by mail, please provide two copies. To receive PHMSA's confirmation receipt, include a self-addressed stamped postcard. Internet users may access all comments at *http://www.regulations.gov,* by following the steps above.

Note: PHMSA will post all comments without changes or edits to *http://www.regulations.gov* including any personal information provided.

FOR FURTHER INFORMATION CONTACT: Mike Israni by phone at (202) 366–4571 or by e-mail at *Mike.Israni@dot.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

Existing integrity management regulations cover operators of hazardous liquid pipelines (49 CFR 195.452, published at 65 FR 75378 and 67 FR 2136) and gas transmission pipelines (49 CFR 192, Subpart O, published at 68 FR 69778). These regulations require that operators of these pipelines develop and follow individualized integrity management (IM) programs, in addition to PHMSA's core pipeline safety regulations. The IM approach was designed to promote continuous improvement in pipeline safety by requiring operators to identify and invest in risk control measures beyond core regulatory requirements.

PHMSA published a Notice of Proposed Rulemaking (NPRM) on June 25, 2008, (73 FR 36015) to extend its integrity management approach to the largest segment of the Nation's pipeline network—the gas distribution pipelines that directly serve homes, schools, businesses, and other natural gas consumers. Significant differences between gas distribution pipelines and gas transmission or hazardous liquid pipelines made it impractical to apply the existing regulations to distribution pipelines. The proposed rule incorporated the same basic principles as current integrity management regulations but with a slightly different approach to accommodate those differences. PHMSA worked with a number of multi-stakeholder groups to help determine the best way to apply integrity management principles to distribution pipelines before publishing the NPRM. The work and conclusions of the stakeholder groups are described in the NPRM.

As described in the NPRM, the proposal was responsive to recommendations from DOT's Inspector General and the National Transportation Safety Board. It also proposed to implement a requirement in the Pipeline Inspection, Protection, Enforcement and Safety Act (PIPES Act) of 2006 that integrity management requirements be established for distribution pipelines.

The proposed rule also included a provision to allow distribution pipeline operators to apply for approval from their safety regulators to adjust the intervals at which they perform specific safety requirements that current regulations require to be performed at specified intervals. This provision recognized the basic principle underlying integrity management—that operators should identify and understand the threats to their pipelines and apply their safety resources commensurate with the importance of each threat. Operators devote resources to comply with the core pipeline safety regulations. These safety resources can be made available for other purposes where a low level of risk makes a longer interval acceptable. Applying those resources to other safety tasks to address higher risks can result in an overall improvement in safety.

In addition, the proposed rule would have required distribution pipeline operators to install excess flow valves (EFV) in certain new and replaced residential service lines. This provision also implemented a requirement in the 2006 PIPES Act.

II. Comments on the NPRM

PHMSA received 143 letters commenting on the proposed rule. Of these:

- 12 were from associations. This includes national and regional associations of gas distribution pipeline operators and the National Association of Pipeline Safety Representatives (NAPSR), the Association of State Pipeline Safety Regulators.
- 62 were from municipal distribution pipeline operators.
- 45 were from non-municipal local distribution pipeline operators.
- 15 were from State pipeline safety agencies.
- 5 were from companies supplying products and services to the industry.
- 1 was from a citizens' group.
- 1 was from the Plastic Pipe Database Committee (PPDC).
- 1 was from the Gas Piping Technology Committee (GPTC).
- 1 was from an anonymous commenter.

General Comments

Virtually all comment letters supported the proposed rule, with notable exceptions for some of its provisions. The vast majority of commenters commended PHMSA for the inclusive way in which the background for the proposed rule was developed. Most commenters who took exception to particular provisions in the proposed rule objected to those provisions as being beyond what stakeholder groups had suggested.

The anonymous commenter suggested that the proposed rule is not needed and noted that accidents happen. One operator suggested that this entire proposal is unnecessary, since existing rules are adequate to assure safety. One operator also opposed the proposed rule, noting that system differences mean that the concepts used on transmission lines do not apply to distribution and suggesting that the burden of implementing integrity management for distribution pipelines would cause more harm than good. One state pipeline safety regulatory agency also opposed the proposed rule, noting that the existing body of regulations has resulted in a very low number of deaths annually from distribution pipeline accidents and suggesting that the new requirements would therefore not be cost-beneficial. The State agency also noted that the new rule will impose additional work on already-burdened State pipeline safety regulators.

PHMSA has considered these comments but still considers it necessary to issue a rule requiring integrity management for distribution pipelines. While accidents may continue to occur, that does not mean that reasonable actions should not be taken to avoid those accidents that could be prevented. PHMSA concludes that the flexibility inherent in the rule, as modified in response to other comments (described below), adequately addresses concerns based on differences among distribution pipelines. PHMSA also concludes that the changes made in response to other comments will reduce implementation costs and that the rule will be cost-beneficial. PHMSA is working with State pipeline safety agencies to increase the level of Federal financial support provided for State programs. PHMSA notes that the vast majority of distribution pipeline operators and State regulators, and the associations that represent them, supported the proposed rule. The existing rules help assure an admirable safety level. Still, significant accidents continue to occur, if infrequently. Experience has shown that incidents are most often caused by a combination of circumstances. These circumstances represent risks for the pipeline involved, but may not affect other pipelines. It is thus not practical to create additional prescriptive requirements to address these pipeline-specific risks. This rule (as the integrity management requirements for other types of pipelines that preceded it) requires that operators evaluate their pipelines to identify the risks important to their circumstances and take appropriate actions to address those risks.

This IM regulation for distribution operators requires an operator to conduct a comprehensive evaluation of its system to better identify threats to the system, to implement additional measures to help prevent accidents from occurring and to mitigate the consequences if an accident does occur. IM provides for a more systematic and comprehensive approach to preventing failures. Accordingly, PHMSA considers this the most effective means to effect further reductions in the number of pipeline incidents. The regulatory analysis supporting this rule considers the improvement in safety that is expected to result and explicitly recognizes the current low frequency of serious accidents.

Specific Comments

There was a broad consensus among commenters that several provisions in the proposed rule should be deleted or significantly modified. In most cases, the consensus included parties from ''commercial'' and municipal operators (and their associations) and State regulators. Many additional comments were made, often suggesting specific changes needed to improve the proposed rule or to make clear the actions required to comply. These comment topics are:

Comment Topic 1 Plastic Pipe Reporting.
Comment Topic 2 Performance Through People.
Comment Topic 3 ''Damage'' Definition.
Comment Topic 4 Implementation Time.
Comment Topic 5 Rule Structure and Implementation.
Comment Topic 6 Alternative Intervals.
Comment Topic 7 IM Requirements for Master Meter and LPG Operators.
Comment Topic 8 Transmission Lines Operated by Distribution Operators.
Comment Topic 9 Part 192—Requirement References.
Comment Topic 10 Hazardous Leak Definition.
Comment Topic 11 Required Documentation.
Comment Topic 12 Excess flow valves.
Comment Topic 13 Guidance.
Comment Topic 14 Leak monitoring.
Comment Topic 15 State authority.
Comment Topic 16 IM program evaluation and improvement.
Comment Topic 17 Permanent marking of plastic pipe.
Comment Topic 18 Continuing surveillance.
Comment Topic 19 Information gathering.
Comment Topic 20 Knowledge of pipeline.
Comment Topic 21 Threat identification.
Comment Topic 22 Risk assessments.
Comment Topic 23 Performance measures.
Comment Topic 24 Regulatory analysis.
Comment Topic 25 IM for new pipelines.
Comment Topic 26 Annual report form.

A discussion of each comment topic and PHMSA's response to each follows:

Comment Topic 1: Plastic pipe reporting.

Commenters universally rejected the proposal to require reporting of all plastic pipe failures. Commenters noted that the plastic pipe data committee (PPDC) includes representatives of all stakeholder groups and has several years of data for identifying trends that would be lost if PPDC were no longer used. Commenters believe PPDC has done an excellent job of collecting and analyzing operating experience with plastic pipe. According to commenters, operators of approximately 75 percent of installed plastic pipe mileage voluntarily provide information to PPDC. While this is less than the 100 percent participation that would result from a mandatory reporting requirement, commenters maintained this is sufficient data to draw statistically significant conclusions about the performance of all plastic pipe.

Many commenters thought PHMSA's concern that information from PPDC is not available to the entire industry is unjustified. These commenters noted that PPDC issues summary reports, that trade associations (who participate in PPDC) provide information to their members, and that PHMSA has issued advisory bulletins concerning significant PPDC conclusions. Many operators commented that they would not have the time or resources to review detailed failure information on their own, and that the information currently provided by the trade associations and PHMSA advisories is useful to them.

Some commenters suggested that the rule require operators to make use of this information. AGA and one operator suggested that the requirement to report plastic pipe failures be replaced with a requirement that operators consider industry and government advisories in evaluating plastic pipe performance as part of their DIMP programs. They believe this would be more effective in addressing PHMSA's underlying concern of operators not considering relevant information than would mandatory reporting. All who addressed this subject agreed that replacing the current system with mandatory reporting of all failures would be unreasonably burdensome and would not improve knowledge or safety. PPDC commented that mandatory reporting is not needed as they have the necessary structure and participation. PPDC suggested that it would take years to collect enough data to duplicate the information they already have on hand.

PHMSA response: PHMSA is persuaded that the data collection burden is not warranted at this time given the current system of PPDC analysis of plastic pipe failure trends and dissemination of lessons learned from this analysis via PPDC reports and trade association communications and through our advisories. The final rule does not include the requirement to report all plastic pipe failures.

The proposed requirement included reporting failures of couplings used with plastic pipe. PHMSA has retained this requirement for compression couplings. This final rule includes a requirement that operators report failures of compression coupling as part of their annual reports. This provision was an included part of proposed § 192.1009, which would have required reporting of ''each material failure of plastic pipe (including fittings, *couplings,* valves and joints)'' (emphasis added). As described above, PHMSA has deleted from the final rule the requirement to report plastic pipe failures, since it was persuaded by the public comments that PPDC is adequately collecting and analyzing this data and disseminating the results of its analysis broadly. PPDC does not, however, collect data on couplings used to join plastic pipe, since the body of most couplings is metal. Coupling failure has been the cause of a number of incidents on distribution pipelines in recent years and the subject of several PHMSA advisories. Additional data concerning coupling failures is needed to enable PHMSA to determine if additional requirements are needed to help prevent future incidents from coupling failure. Accordingly, PHMSA has retained the included element of reporting of coupling failures in this final rule.

The final rule provision is not limited to couplings used on plastic pipe. PHMSA understands that the principal use for couplings in distribution pipeline systems is to connect plastic pipe or to connect plastic pipe to metal pipe (including risers, etc.). PHMSA recognizes that it is possible for mechanical couplings to be used to connect metal pipe to metal pipe, and that reporting of failures involving such connections would not have been encompassed by the proposed requirements related to plastic pipe in the NPRM. PHMSA believes that use of couplings in applications that do not involve plastic pipe is rare. Nevertheless, PHMSA invites public comment on the extension of this proposed requirement to include reporting of failure of couplings used in metal pipe. Comments should be submitted by January 4, 2010. Based on the comments we receive, we will consider modifying the provision. At the end of the comment period, we will either issue a modification or a notice stating that the section stands as written.

An operator is not required to collect coupling failure information until January 1, 2010. We expect to issue any modifications to this section prior to that date. If we are delayed in issuing a modification, we will then consider further delaying the compliance date for section 192.1009. PHMSA is issuing, in conjunction with this final rule, a 60-day notice regarding amendments to the Annual Report form, which includes changes related to this reporting requirement. Until PHMSA announces a modification, operators should plan to report the information described in the 60-day notice.

Comment Topic 2: Performance through people.

Commenters opposed the performance through people (PTP) element and the proposed requirement that each IM plan include a section entitled ''Assuring Individual Performance.'' Commenters maintained that the proposed requirement is vague and likely unenforceable and that it creates confusion and diminishes the focus on the core issues of importance to IM. They pointed out, as did PHMSA in the NPRM's preamble, that other regulations currently address the impact of people on pipeline safety. These regulations include Operator Qualification, Drug and Alcohol requirements, Damage Prevention, and Public Awareness. Commenters noted that the proposed PTP requirement is unclear about what, if any, additional actions are expected, and that having to refer to actions taken under these other requirements in an IM plan creates an unnecessary additional paperwork burden. NAPSR, American Public Gas Association (APGA), GPTC, and operators suggested that PHMSA should not presume that action is required by all operators to address the threat of inappropriate operation. These commenters noted that studies, including those conducted by the American Gas Foundation (AGF) and Allegro and referred to in the preamble of the NPRM, have shown that this threat poses a very small risk; PHMSA data shows it to be the cause of only 3% of all leaks.

PHMSA response: PHMSA has not included PTP requirements in the final rule. PHMSA agrees the provision is largely duplicative of other existing regulations. Nevertheless, the final rule still requires that operators evaluate all threats applicable to their pipeline systems. Thus, operators for which inappropriate operation is a threat of concern will be required to address that threat.

Comment Topic 3: ''Damage'' definition.

In the NPRM, PHMSA proposed to add a new definition for ''damage'' applicable to the IM subpart. The proposed definition was ''any impact or exposure resulting in the repair or replacement of an underground facility, related appurtenance, or materials supporting the pipeline.'' This term is being defined because of a provision in the proposed rule that would require reporting the number of excavation ''damages'' as a performance measure. Industry stakeholders universally commented that the definition of ''damage'' should be limited to excavation damage and to damage that causes loss of gas (immediate leaks). GPTC would further limit the definition to ''known'' excavation damage. States and NAPSR suggested defining excavation damage vs. damage, but did not suggest limiting damage of interest to damage causing leaks. One operator suggested that the definition should also include instances in which damaged pipe is retired in place because damaged pipe and appurtenances are not always repaired or removed; the operator suggested that the definition should focus on the unplanned nature of the repair, removal or retirement.

The commenters pointed out that operators report data regarding leaks in their annual reports but not other damage. Operators are not now required to collect data on damages that do not result in leaks. Commenters contended that extending the definition of damage to encompass situations that do not cause leaks will cause loss of continuity with previous data and may cause confusion. Some noted that statistically better conclusions can be drawn if such continuity is maintained. Some commenters asked whether coating damage or damage to anodes/test wires would be included. Others noted that discovery of latent damage, that may have occurred years earlier, is not a measure of the current effectiveness of a damage prevention or integrity management program. Industry expressed concern about the additional recordkeeping burden associated with capturing data on non-leak damages.

Two operators suggested that the term ''exposure'' be eliminated from the proposed definition of damage (or excavation damage) because it is unclear what this term adds. They question, for example, whether washouts would be included.

PHMSA response: PHMSA agrees that excavation damage is of principal concern and is the term that should be defined. PHMSA does not agree, however, that only excavation damage that results in a leak is of concern.

Mitigating the threat of excavation damage means implementing or continuing actions that will minimize the likelihood that excavation near the pipeline will cause damage. Operators must seek to prevent excavation ''hits'' of the pipeline, whether a hit results in leakage or not (*e.g.,* a glancing blow or insufficient force to cause a leak). That a hit occurs, regardless of whether it causes leakage, is an indication that the actions intended to prevent such an occurrence have failed. Operators cannot adequately evaluate the effectiveness of their mitigative actions for this threat, and PHMSA cannot evaluate the effectiveness of these actions on a national level, if non-leak events are excluded. Assuring continuity with past data is less important than assuring that the data being collected appropriately addresses the event of concern.

At the same time, PHMSA is sympathetic to the need to have well-defined criteria identifying what damage is to be included in performance monitoring and understands that a definition based on whether a leak occurred would provide clarity; however, it would not allow operators and PHMSA to monitor the effectiveness of damage prevention measures.

Pipeline operators, as well as operators of all underground facilities, need to evaluate the effectiveness of damage prevention efforts. The Common Ground Alliance (CGA) is a national group involving operators of all types of underground facilities, as well as representatives of excavators and others who play a part in preventing damage to underground facilities. CGA has established the Damage Information Reporting Tool (DIRT) to collect information submitted voluntarily concerning damage to underground facilities. Some pipeline operators participate in DIRT. DIRT defines damage based on whether repair or replacement of an underground facility is required. This is very similar to the definition proposed in the NPRM, which also relied on the need to repair or replace as the defining criterion. PHMSA has modified the definition in the final rule to match more closely the language used in the DIRT definition of excavation damage. PHMSA has omitted the phrase ''of exposure'' used in the DIRT definition, since this refers to damage from causes other than excavation (*e.g.,* washout). The changes in the definition in the final rule will provide the needed clarity and will also facilitate potential comparison of distribution pipeline damage prevention performance to that of other underground facilities for which CGA collects data. This change also obviates the need to include retirement in the definition because retirement of an active pipeline will usually involve replacement or bypass. Damage to the protective coating or to the cathodic protection that requires repair/replacement is damage of concern in evaluating the effectiveness of damage prevention measures; therefore, the definition in the final rule clarifies that damage necessitating repair to coating or to cathodic protection constitutes excavation damage.

Comment Topic 4: Implementation time.

Many industry commenters objected to the requirement that IM plans be ''fully implemented'' within 18 months. They suggested that ''fully'' be deleted. IM plans inherently involve learning more about the pipeline systems and associated risks, and it is not clear when they will be ''fully'' implemented.

A few operators suggested we clarify what is meant by ''implement.'' They noted that it was not clear if this meant that all databases must be fully populated and that, if so, it cannot be accomplished in 18 months. Many industry commenters also objected to the proposed requirement that implementation occur within 18 months. They argued that many operators will need to make changes in how they collect and manage data, including the need to purchase new computers and develop new databases or make other IT changes, and that these changes take time. Industry also suggested that it is not practical to expect that plans will be implemented, databases will be fully populated, etc., for all portions of complex distribution systems in a short period of time. AGA noted that Congress allowed 10 years for full implementation of gas transmission IM. Commenters varied in their suggestions for a different implementation deadline. Many suggested 24 months, with one operator clarifying that after such a period operators should be required to have developed and implemented a ''framework'' that will further develop over time. One operator suggested one year to develop plans/programs and another year to implement. Others suggested variations on this approach, with 1½ years allowed either for development or implementation.

One operator commented that the proposed rule was too ambiguous as to the actions required to implement its provisions. It stated that the rule lacks the clarity needed to know what must be done.

PHMSA response: PHMSA has deleted the term ''fully'' from the final rule. PHMSA has retained the 18-month requirement. PHMSA recognizes that implementing IM plans involves learning and revision but does not agree that this means it is necessary to stretch out the implementation deadline. It is important to implement—to begin the iterative learning process—as soon as practical. With ''fully'' being deleted, as noted above, it is clear that implementation is not expected to mean that all problems have been identified and resolved. PHMSA notes that 18 months is consistent with the period suggested by many commenters for developing IM programs and, with deletion of the concept of ''fully implement,'' believes this period is still appropriate.

AGA's comment is incorrect. Congress allowed 10 years for gas transmission operators to complete baseline assessments (*i.e.,* physical inspection) of the portions of their pipelines in high consequence areas.[1] The proposed rule did not include a provision for distribution pipeline operators to conduct such assessments. Transmission pipeline operators were required to develop and implement IM plans in one year.[2]

PHMSA disagrees with the comment that the rule is ambiguous. This comment was not echoed by the many other operators or the trade associations that submitted comments. Some commenters identified specific areas where they believed further clarity was needed and PHMSA has made changes where appropriate, as described below. As a result, PHMSA concludes that the actions required to implement the final rule are clear.

Comment Topic 5: Rule structure and implementation.

Several commenters addressed specific issues associated with the structure of the rule and language in proposed § 192.1005 addressing what gas distribution operators must do to implement this new subpart. A consultant and GPTC both suggested that section headers within the rule not be written as questions because questions are inherently longer than classic titles, and make the rule harder to use.

AGA and several distribution operators objected to the proposed requirement that procedures describe the ''processes'' for developing, implementing and periodically improving IM elements. The Iowa Utilities Board (Iowa) also suggested that this provision be modified to remove the reference to processes. The commenters noted that the term is unclear and could be interpreted to require elaborate algorithms. They noted that the stakeholders concluded that major technical changes are not needed, which they interpret to mean that major ''processes'' are not required to implement distribution IM. They believe that deleting the term does not affect the meaning of the proposed requirement.

PHMSA response: The structure of the regulation as question and answer is part of the long-standing Government-wide requirement to write regulations in ''plain English.'' PHMSA has been consistently using this format in its pipeline rulemakings for some time. PHMSA has revised § 192.1005(b) to delete the reference to ''processes.''

[1] Pipeline Safety Improvement Act of 2002, Section 14.

[2] 49 Code of Federal Regulations, Section 192.907.

Comment Topic 6: Alternative intervals.

Commenters generally favored the proposed requirement that would allow operators to propose alternative intervals for part 192 requirements. There were a number of comments related to this provision and its implementation.

a. Concept.

AGA, GPTC, and many gas distribution operators supported the proposal. They noted that shifting of resources often is necessary to assure safety efficiently. They believe that the proposed rule would not be cost-beneficial unless it allowed for such adjustments. They noted that risk-based intervals are more effective and efficient and can result in improved safety and reduced costs. In response to a preamble question concerning advantages and disadvantages of allowing operators to adjust required intervals, some operators commented that the engineering work needed to establish new intervals and the need for State review and understanding of the basis were disadvantages of PHMSA's proposal.

PHMSA response: This provision is intended to facilitate realignment of safety resources, where appropriate, to promote efficiency without compromising safety. Because operators are in the best position to understand the risks on their system, and where resources should be effectively applied, this provision is designed to give operators that latitude to effectively manage their systems. Approval from regulators is necessary to prevent the abuse of this provision. Operators are not required to apply for adjusted intervals. If the burden of engineering work and seeking State review are too burdensome, the operator may continue to use the intervals in the regulations.

b. Process.

AGA, GPTC, and several operators suggested that it will be important for PHMSA to provide guidance to the States for implementing alternative intervals. One operator suggested a federal ''template'' to be used by the States. Commenters suggested that consistency would be particularly important for large companies that operate pipelines in multiple states. One commenter stated the process should be ''streamlined.'' NAPSR, however, asserted that approval should be per State procedures, with flexibility provided for each State to consider its particular circumstances. Iowa also noted that such guidance is not needed.

The Massachusetts Department of Public Utilities suggested that a process needs to be defined for appeal of decisions related to proposals for alternative intervals. They believe that such a process should be consistent with that for waivers under 49 U.S.C. 60118.

PHMSA response: State authority and regulatory structures differ, and some state regulators may need to seek additional authority (from their state government) to implement this provision. States will implement this provision under individual state statutory authority in accordance with the applicable certification under 49 U.S.C. 60105 of this title or agreement under section 60106. PHMSA believes most states will be able to establish procedures under existing authority and may already have procedures that can be used for this purpose.

PHMSA agrees with NAPSR that states need flexibility in implementing this provision. PHMSA will develop criteria for evaluating operator's alternative interval proposal in the states where PHMSA exercises enforcement authority over distribution pipelines. States may be able to use those criteria where they exercise enforcement authority. Factors important to each regulatory authority's consideration of proposed changes to intervals for safety actions are also likely to differ. These differences make it impractical to develop a common ''template'' process.

PHMSA agrees that the regulatory authority responsible for reviewing the request should institute appropriate administrative procedures for processing requests for alternative intervals, to include a process for appealing a decision. States will establish their own procedures for review, and it is not appropriate for PHMSA to impose a ''streamlined'' process on state actions.

c. Approving agency.

NAPSR, States, and some industry commenters suggested that the rule be clarified that approval must be requested from the regulatory authority exercising jurisdiction. They considered the language in the proposed rule vague as to whether a state or PHMSA was the approving agency, or whether an operator could apply to either. One operator suggested that approval should be by States.

PHMSA response: PHMSA has always intended that the alternative interval provision in this rule would allow the regulatory authority exercising jurisdiction over the operator of the distribution pipeline to act on a proposal to use alternative intervals. We have clarified the language in the final rule to remove any implication that an operator may seek approval from either

PHMSA or a state. Most distribution pipelines are regulated by state agencies and approval of changes proposed by those operators will be by the state.

d. Evaluation of proposals.

A number of commenters addressed the proposed requirement that operators proposing alternative intervals demonstrate that a reduced frequency will not significantly increase risk. NAPSR proposed that operators should be required to demonstrate enhanced system safety or, at minimum, that operation would be at least as safe under the proposed alternative. Iowa suggested a requirement for a substantially equal or superior level of safety. One operator requested that the meaning of a significant increase in risk be clarified by example, noting that the proposed language is unclear. Another suggested that the rule should not require a proposal for an alternative interval to include a no-significant-risk demonstration; the commenter noted that the core pipeline safety regulations are not risk based and suggested that risk must be considered on an overall basis vs. change-by-change.

Although commenters generally supported consistency between regulatory authorities, commenters also suggested that there is no single basis for judging the adequacy of the engineering basis for a proposed change, and that it is not practical or necessary to define requirements for performance/data analysis. One operator suggested that engineering analyses should be judged on whether they are performed by an engineer, are subject to internal review, use good data, and include logical analyses and conclusions. GPTC and one operator suggested that no additional analysis should be required if performance measures show that risk mitigation is effective.

AGA and several commenters noted that there should be no arbitrary limit on the change in interval that will be allowed.

PHMSA response: The rule does not require and PHMSA does not contemplate that operators will produce a precise quantitative estimate of risk. Accordingly, PHMSA recognizes that it is not easy to demonstrate that any action produces no significant increase in risk. However, regulating safety requires judgments weighing risk versus costs. Judgments of this type are what operators will need to support their proposals and regulators will need to consider. PHMSA does not agree that any reduction in safety intervals is unacceptable because the change alone would result in some increase in risk. Instead, the regulatory authority needs to make an overall judgment on the adequacy of proposed changes.

PHMSA has revised the final rule to require that alternatives, as part of the overall IM plan, provide an equal or improved overall level of safety. This change is intended to eliminate any implication that a quantitative estimate of risk is required. PHMSA expects that operators will be conscientious in demonstrating that proposals produce a level of safety that is equal or improved, on an overall basis, and that states will be reasonable in judging the adequacy of proposed changes.

PHMSA also agrees that it is unnecessary and likely impractical to establish specific criteria for approval of proposals for alternative intervals. Each proposal must be considered as a whole and on its own merits. PHMSA has not adopted any of the various alternatives suggested by commenters because each regulatory authority must exercise its judgment based on the circumstances of each request. However, PHMSA also recognizes the industry's need for some degree of consistency in how proposals are evaluated. PHMSA intends to work with the states to help assure a degree of consistency.

PHMSA is not specifying any limit on the intervals that may be authorized by the regulatory authority. The regulatory authority will be responsible for determining safe intervals based on the information in each operator's proposal.

e. Opposition.

The Florida Public Service Commission opposed the proposal to allow alternative intervals. The Commission maintained that waivers (their characterization) inherently reduce the established minimum safety level. They believe that processing these proposals will be burdensome and that proposed waivers would generally not be approved. If the provision is retained, they suggest that the risk analysis used as a basis for changes must be transparent to the regulator. They also suggest that the code be revised to require that operations and maintenance (O&M) plans be required to contain a summary of maintenance tasks and approved periodicity, since it will no longer be possible to use a common inspection template if operators are not required to conduct actions at the same intervals.

PHMSA response: Waivers from regulatory requirements (sometimes also called special permits) are a common regulatory tool. PHMSA permits pipeline operators to seek a special permit [3] and considers such requests on their merits. Although required periodic actions address threats of concern and a reduction in the periodicity of those actions inherently involves an increase in risk, adjustments to the frequency may be warranted when safety resources are applied to other areas of greater concern. Contrary to the assertion of the commenter, the use of waivers can result in a reduction in overall risk (i.e., improvement in safety), and regulators must make judgments regarding the overall effect of proposed changes.

The final rule requires that the regulatory authority make the decision to approve or disapprove any proposal for alternative intervals. PHMSA sees no need to add a requirement that risk analyses used for this purpose be ''transparent'' to regulators because an operator will have to work with the regulatory authority to provide enough information to evaluate the requested change. PHMSA also does not agree that a requirement that each O&M plan contain a summary of maintenance tasks and periodicity is needed. Florida, or other states, may require such changes or other information needed to facilitate their inspections as part of their process of reviewing an operator's proposal.

f. Costs and benefits.

Commenters generally agreed that any additional cost to states should be minimal. (NAPSR concurred, provided that States are allowed to follow their current procedures.)

Some comments suggested that the alternative interval provision will be of limited benefit. One operator suggested that the proposed requirement is too burdensome, involving significant administrative costs and burden associated with the need to use risk analyses to justify all changes. Another noted that there are limitations on the ability of operators to move resources from low-risk areas, including potential changes to labor agreements and reassignment of personnel. They requested that the rule recognize these limitations.

Some operators are concerned that failure of state regulators to approve alternative intervals will result in implementing additional actions to control risks without offsetting reductions where risk is low, thus increasing total costs.

PHMSA response: Cost issues are addressed in the Regulatory Impact Analysis and the Regulatory Flexibility Analysis located in the docket for this rulemaking.

This provision imposes no burden on operators. Use of alternative intervals is voluntary. Operators who conclude that obtaining approval would be too burdensome or that it would be too difficult to realign safety resources need

[3] 49 United States Code, Section 60118.

not apply. PHMSA therefore sees no need to revise the rule language to recognize that such situations may exist.

Operators apply safety resources to purposes other than inspections/actions required periodically by regulation. Operators will be able to realign those resources without regulatory approval, based on insights that their risk analyses may supply, providing a means by which they can make their safety activities more efficient, thereby permitting them to avoid increased costs.

g. An industry consultant suggested that the current requirement to inspect inside meter sets for atmospheric corrosion at 3-year intervals should be changed. He noted that experience shows these inspections are not needed and it is more efficient to change the requirement on a national basis.

PHMSA response: This is an example of a required periodic inspection where an operator could propose a modification if its analysis showed devoting resources in another area would be more beneficial from a safety standpoint. Changing this periodic requirement on a national basis is outside the scope of this rulemaking.

h. Some operators suggested that implementation of alternative intervals should be allowed, based on risk analysis, without requiring regulatory approval. They noted that reductions in effort, where found appropriate, are an integral part of implementing a risk-based approach. They expressed concern that state regulators will be unwilling to approve reductions from established intervals which, although not risk-based, are an accepted norm.

PHMSA response: PHMSA does not think regulatory approval should be eliminated. Regulatory oversight is appropriate for changes that involve reducing safety actions currently required by regulation. PHMSA recognizes that there may be some reluctance to approve reductions from an established norm; however, PHMSA plans to assist states to determine appropriate methods to evaluate proposals. PHMSA believes that these efforts will serve to address any reluctance on the part of state regulators to consider alternative intervals.

Comment Topic 7: IM requirements for master meter and LPG operators.

Many comments addressed the proposed limitation of requirements for master meter and LPG operators (MM/LPG) and PHMSA's request for comment on these limitations. PHMSA asked whether the proposed limitations were appropriate, whether further limitations were needed or if these operators should be exempt from IM requirements. PHMSA also asked whether similar limitations should be afforded to other types of operators.

a. Proposed limitations are inappropriate.

Two major trade associations addressed the proposed limitations for master meter and LPG operators. (Neither group's members include operators of this size.) AGA suggested that these smaller operators should be required to implement distribution IM, but that the requirements should be scalable, recognizing the uncomplicated nature of their facilities.

APGA agreed that MM/LPG should not be excluded from IM requirements. They noted that if mandatory reporting of plastic pipe damages is eliminated (as they suggested) the limitation essentially becomes an exclusion from filing annual reports. Master meter operators are currently excluded from annual report requirements. APGA ''would not object'' to adding a requirement that master meter and LPG operators evaluate and prioritize risk. APGA sees risk ranking as an integral part of assessing risks, and believes it will occur whether or not it is required explicitly in the rule.

NAPSR, Connecticut Department of Public Utility Control, Pennsylvania Public Utility Commission (PPUC), and several operators also commented that MM/LPG should be subject to IM requirements. They referenced the conclusion of the stakeholder groups that distribution IM should apply to all distribution operators. These commenters did not agree that these operators pose less risk, and maintained that simpler systems will inherently have simpler programs. They also noted that some master meter operators are much larger than the NPRM stated. PPUC explained that there are two master meter operators in its state with more than 6,000 customers. Other commenters noted that there is limited data on these systems, since they do not report incidents, and thus the risk may not be small.

The Arizona Corporation Commission (AZCC) commented that all LPG operators should not be treated like master meters, since some serve small towns, like local distribution companies and have the same limited control over the principal threat of excavation. AZCC suggested that LPG operators who serve a city, town, or other municipality within a specified service area as defined by the state agency with authority should meet the same requirements as other distribution system operators. AGA and NAPSR noted that LPG poses unique risks because the product is heavier than air, unlike natural gas. Leaks from these systems will not safely disperse, as will leaks from natural gas distribution systems.

PHMSA response: PHMSA is persuaded that there is a reasonable criterion to distinguish between LPG operators. PHMSA's concern with overwhelming small operators with limited resources and technical expertise is not applicable to LPG systems serving hundreds or thousands of customers because those operations are more like small natural gas distribution system operators. PHMSA notes that existing regulations include a criterion to differentiate between large and small LPG operators. Section 191.11 excludes LPG operators serving fewer than 100 customers from a single source from filing annual reports. Other LPG operators are required to file such reports. PHMSA has revised the final rule to embrace this same criterion. LPG operators serving fewer than 100 customers from a single source are treated like master meter operators. Other LPG operators must meet the same requirements as natural gas distribution pipeline operators.

We are also persuaded that MM/small LPG operators should not be exempt from ranking risks—a requirement we had applied to all other distribution operators in the proposed rule. We believe that these operators will gain a better understanding of their systems by going through the ranking process. Ranking the risks is almost inherent in the other requirements and should not impose an additional burden on these operators. PHMSA has added an element to rank risks to the requirements applicable to MM/LPG systems.

b. MM/LPG should be subject to limited IM requirements.

The Indiana Utility Regulatory Commission does not agree that MM/LPG should be subject to the same requirements as other operators. Indiana commented that although there are reasons that master meter operators could be perceived as posing higher risk (*e.g.,* lack of expertise/resources, distributing gas is not primary business, high population density), there has been no record of serious incidents at master meters in Indiana. They stated that these operators struggle to comply with existing rules and will have limited ability to analyze risks, even if the computer program APGA is developing (Simple, Handy, Risk-based, Integrity Management Program—SHRIMP) is available. Indiana suggested we should either exclude master meter operators from this rule or subject them to more limited requirements and allow them to spend their limited resources achieving compliance with existing regulations.

While not supporting total exclusion, Missouri and New Hampshire state regulators supported limited requirements for MM/LPG. AZCC commented that the rule should be prescriptive and simple for master meter and small LPG operators, since these operators have limited capability, can be easily overwhelmed and may, if that happens, do nothing. The New Mexico Public Regulation Commission (NMPRC) supported excluding MM/LPG from administrative requirements of the proposed rule.

Iowa did not take a position on limiting requirements; however, Iowa and a large operator suggested that evaluation and prioritization of risks should not be excluded for MM/LPG. They see this as a critical step, and not particularly burdensome.

PHMSA response: While PHMSA agrees that there are some ''large'' MM operators, most of them are very small. Unlike the large/small LPG operator distinction, which exists in current regulations, all MM operators are treated the same, irrespective of size. Therefore, in this final rule, all MM are subject to the limited IM requirements.

The final rule imposes requirements similar to those for other operators but with more limited requirements for documentation, consistent with how these operators are treated in other regulations. They will not be required to report performance measures as they do not file annual reports.[4] Although these requirements are similar to those applicable to other operators, we have presented them separately, emphasizing that these programs should reflect the simplicity of the pipelines.

Some comments in response to the NPRM and comments made during earlier stakeholder discussions have disagreed with PHMSA's contention that MM/LPG operators pose less risk. Risk is generally considered to be the product of the likelihood of adverse events and their consequences. Determining risk thus requires knowledge of how often events occur and the consequences they produce. MM/LPG operators are not required to submit written incident reports. They are, however, required to make telephonic reports.[5] Events with serious consequences (*e.g.,* death or serious injury) are also likely to be reported in local news and thus to come to the attention of regulatory authorities. PHMSA therefore believes it is unlikely a large number of significant events have occurred on MM/LPG systems that are not reflected in incident data. That data includes few serious incidents on MM/LPG systems, supporting PHMSA's contention that the risk from these systems, while not zero, is relatively low. Indiana's comments about the dearth of serious accidents in the incident record are consistent with PHMSA's understanding of the risk of these systems.

c. MM/LPG should not be subject to IM requirements.

The National Propane Gas Association (NPGA) suggested that LPG operators should be exempt entirely. NPGA sees no perceived benefit from compliance with the proposed requirements. They noted that LPG systems are very small, that they generally include pipe runs measured in feet vs. miles, and that the total quantity of gas that could be released in an accident is limited by the capacity of the supply tanks, a limitation not shared with natural gas systems. NPGA maintained that their members are already sufficiently regulated, mostly by states and through the incorporation of NFPA Standard 58 (NFPA–58) into Part 192 by reference. They believe that NFPA–58 mirrors the requirements of Part 192 and the proposed rule and noted that the standard is already recognized as the primary governing standard in § 192.11(c) which states that the standard prevails in the event of a conflict between its provisions and Part 192. NPGA also suggested that applying this rule to LPG operators could have unintended consequences. In a competitive environment to reduce costs, operators could break up their systems to fall outside of regulation, thus removing safety oversight completely.

PHMSA response: In the NPRM we proposed a simpler set of IM requirements for MM/LPG operators, but we asked if these operators should be completely excluded from IM requirements. The bulk of comments supported limited requirements but opposed excluding these operators, arguing that simple pipelines would need only simple IM plans. In the final rule, PHMSA has not excluded these operators.

LPG presents unique hazards; accordingly, PHMSA believes pipeline safety will be enhanced by larger LPG operators engaging in more robust integrity management activities. As discussed above, large LPG operators are subject to the full IM requirements in the final rule, including the administrative requirements. Because of the physical nature of LPG and the safety risks it presents, PHMSA is not persuaded that small LPG operators should be exempted. Furthermore, NFPA Standard 58 does not ''mirror'' the integrity management requirements in this rule and does not adequately address the safety measures provided by this final rule. IM requirements will complement NFPA–58.

d. Limitations for small gas distribution operators (other than MM/LPG).

A consultant suggested that distribution IM should be limited to large operators at this time. He noted that the PIPES Act does not mandate such requirements for small operators and suggested that a phased approach would be prudent. He believes that small operators do not have the personnel or background to implement these requirements and that the associated costs will likely exceed the benefits. He noted that the risk from third-party damage on such systems is small, as operators' personnel see most of the system daily. He supported exclusion for small operators similar to that proposed for MM/LPG and suggested that PHMSA collect additional data to see if additional requirements are needed for these operators. A large operator also supported limited requirements for small operators, and would include the number of customers or mileage as a threshold criterion.

The Washington Citizens Committee on Pipeline Safety commented that the number of services should not be used alone to delineate small systems. They suggested that the type and uniformity of material, system complexity, geographic spread, and other risk factors be considered as well.

APGA suggested that criteria defining a small system should not include limitation to one pressure district and should not limit the type of appurtenances or equipment. APGA commented that these differences do not affect risk. Small distribution operators already file annual reports, so APGA believes that extending the proposed limitations for MM/LPG would have no value for other small operators.

NMPRC would exclude small operators from the administrative requirements of the proposed rule based on the number of customers or staff. NMPRC concluded that DIMP principles would be beneficial for these operators but that the associated administrative burden is too great.

Missouri would extend all of the MM/LPG limited requirements to small operators.

PHMSA response: PHMSA has not limited this rule to large operators. As

[4] Operators of LPG systems serving more than 100 customers are required to file annual reports.

[5] 49 Code of Federal Regulations, section 191.5.

noted in the NPRM, there is no established threshold to distinguish between large and small operators. In addition, the PIPES Act did not differentiate between large and small distribution operators. The PIPES Act requires, ''the Secretary shall prescribe minimum standards for integrity management programs for distribution pipelines.'' [6] We received few comments regarding how such a threshold might be established.

Rather than delineating explicit thresholds based on operator size, PHMSA expects that operators with small systems will need only simplified plans. Operators will be able to scale their programs according to the complexity of their distribution systems. For example, APGA's SHRIMP program will be available to assist small operators in developing their IM plans.

e. Limitations for other operators.

One operator suggested that limited requirements should also be established for ''circumstantial'' or ''incidental'' operators. This operator is a large company operating hazardous liquid pipelines, but operates a single gas service line from a local distribution company main to a flare at a petroleum barge dock. The operator believes it would be burdensome to have a distribution IM plan for this single service line. A consultant and GPTC also suggested that landfill gas operators should be treated like MM/LPG, since their systems are also small and pose limited risk.

New Hampshire recommended that operators of conventional distribution systems that also operate LPG should be allowed to use a single plan for both. One operator suggested that LDC operators that also operate MM/LPG should be allowed to use a single DIMP plan for both.

PHMSA response: As MM/LPG operators have not been excluded from IM requirements, we see no compelling reason to exclude these other ''small'' operators. PHMSA considers that the analysis of a small, simple system should be relatively straightforward and should result in a basic IM plan. PHMSA notes the commenter operating a single service line to a flare stack may be considered a large volume customer as long as the service line is not on public property. This final rule does not apply to in-plant piping to a large volume customer. Companies that conclude that compliance with a rule would be overly burdensome due to unique circumstances may have the option to apply for a waiver (or special permit), as permitted by the applicable regulatory oversight authority.

The rule does not require that operators of conventional distribution systems that also operate LPG have separate IM plans or that operators of both MM and LPG systems have separate plans for each. We expect that plans developed for their conventional pipelines in response to the other requirements of subpart P should also satisfy § 192.1015. PHMSA agrees that operators with multiple ''systems'' may benefit from having a single IM plan. However, it is also possible that operators who own multiple systems may operate them separately and may desire separate IM plans. Under the final rule, operators will have the flexibility to treat multiple systems under a common plan, or to address them separately.

Comment Topic 8: Transmission lines operated by distribution operators.

Many industry commenters suggested that piping operated by distribution operators but which is classified as transmission (mostly because it operates at greater than 20% SMYS) should be included in a distribution IM plan rather than in a separate transmission IM plan. These commenters suggested that this could be done in this rule or by changing the definition of a transmission line. Commenters explained that this ''transmission'' piping is usually operated as an integral part of the distribution system, and that it would be more efficient to treat it under distribution IM than under a separate transmission IM plan. Several commenters recognized that additional rulemaking may be needed to accomplish this change.

PHMSA response: PHMSA has made no change in response to these comments. The NPRM did not address changing the definition of transmission pipeline; therefore, such an action is outside the scope of this rulemaking.

The transmission IM regulations already provide for alternative treatment of low-stress transmission pipeline (<30% SMYS) [7] in recognition that this low-stress pipe is more likely to fail by leakage rather than by rupture. PHMSA also notes that stakeholder groups studied the appropriateness of treating low-stress transmission pipeline under distribution IM programs. The groups reviewed the existing research concerning the likely failure mode of low-stress transmission pipelines. The record indicated that failure is expected to be by leakage when the failure results from corrosion. It is less clear that the likely failure mode would be leakage when the failure results from prior mechanical damage (*e.g.,* from outside force). The stakeholder groups concluded that additional technical work is needed to better define the threshold stress level at which the likely failure mode transitions from leakage to rupture to determine if low-stress transmission pipeline should be addressed under a distribution IM program.[8] PHMSA may consider this change later but agrees with the stakeholder conclusion that additional research is required to support such a change.

Comment Topic 9: Part 192 requirement references.

NAPSR, APGA, and a number of operators objected to the proposed requirement that all operators must enhance their damage prevention programs (proposed § 192.1007(d)) because the requirement is open-ended. They suggested that § 192.614, which requires such programs, should be revised if current programs are deemed inadequate.

A consultant suggested that leak management requirements should be included in § 192.723 and damage prevention requirements in § 192.614. He generalized this comment by noting that PHMSA should avoid having two regulations that address the same thing. He considers IM as an extension of all of Part 192, and believes that proposed Subpart P should be limited to the high-level approach to IM and related documentation.

PHMSA response: The final rule requires that operators have and implement leak management programs. Programs to manage known leaks are different from periodic leak surveys required by § 192.723.

Operators are required to implement a damage prevention program under § 192.614. After further consideration, PHMSA determined a requirement to enhance damage prevention programs on gas distribution systems through integrity management was impracticable because these programs are largely state-run. PHMSA is persuaded that modifications to damage prevention requirements for distribution systems should be made through amendments to § 192.614 rather than through this rulemaking. PHMSA has eliminated the proposed requirement to enhance damage prevention programs as part of an integrity management effort. Although all references to the damage prevention requirements in § 192.614

[6] 49 United States Code, section 60109(e)(1).

[7] See § 192.941, What is a low stress reassessment?

[8] PHMSA, ''Integrity Management for Gas Distribution: Report of Phase 1 Investigations,'' December 2005, page 23.

have been removed, operators may find through the implementation of their IM programs that improvements to their damage prevention programs are needed.

Comment Topic 10: Hazardous leak definition.

Several commenters suggested we define hazardous leaks. The proposed rule would require reporting of the number of hazardous leaks repaired or eliminated as a performance measure. APGA, GPTC, NAPSR, Washington Citizens Committee on Pipeline Safety, and several pipeline operators suggested that a common definition is needed to assure consistent reporting and the ability to conduct meaningful analysis of this performance measure. Most suggested that the definition of a grade 1 leak in the current GPTC guidelines be adopted. One operator suggested a need to define the term ''leak,'' suggesting that usage is not consistent across the industry. AGA and a number of operators suggested that any needed definitions, other than excavation damage, should be included on reporting forms and their instructions rather than in the code and that this makes subsequent changes, if needed, easier.

PHMSA response: Although a ''hazardous leak'' definition was not explicitly part of our proposal, we did propose regulatory text including that term; accordingly, PHMSA has included a definition for ''hazardous leak'' in the final rule. This definition is drawn from GPTC guidelines already used by many operators to classify leaks. PHMSA does not see a need to define other terms suggested in comments for purposes of this rule. PHMSA is also adding a definition for small LPG operators to improve readability of the Subpart P regulations.

Comment Topic 11: Required documentation.

Proposed documentation requirements were seen as unreasonably burdensome. In particular, the proposed requirements to document ''all'' decisions and changes related to a distribution integrity management (IM) program and to keep all related records for the life of the pipeline were seen as unreasonable.

a. Scope of documentation.

Many commenters suggested deleting all documentation requirements other than the requirement to maintain an IM plan. Others suggested limiting documentation to significant changes, to be defined at the operator's discretion. NAPSR suggested that written procedures and documents supporting threat identification should be limited, noting that excessive documentation does not support safety. NAPSR would limit the requirement for procedures in proposed § 192.1005(b) to those that ''reasonably describe'' processes for developing and implementing IM elements. NAPSR further suggested requiring that procedures ''should provide adequate direction so that a person with reasonable knowledge of gas distribution facilities can follow them and produce a satisfactory result.''

One operator suggested that all the records that are needed are contained in their damage prevention plan and annual reports to PHMSA. Another operator requested clarification concerning the data to be captured to represent the ''material of which [newly installed piping systems] are constructed.'' One operator commented that the term ''documents to support'' decisions, analyses, or processes is vague.

AGA and several operators suggested changing proposed § 192.1015(c) from a written procedure for ranking threats to a description of how threats are ranked. They maintained that detailed procedures are not needed, but acknowledged that master meter and small LPG operators must be able to explain what was done to rank threats.

Florida Public Service Commission requested that operators be required to include in their IM plans a summary containing the risk analysis findings, the effect on safety, and a schedule for actions resulting from the distribution IM program.

PHMSA response: In the NPRM, the section regarding record retention (NPRM § 192.1015; Final Rule § 192.1011) required the following records: A written IM program; documents supporting threat identification; a written procedure for ranking the threats; documents to support any decision, analysis, or process developed and used to implement and evaluate each element of the IM program; records identifying changes made to the IM program, or its elements, including a description of the change and the reason it was made; and records on performance measures. PHMSA has removed this list of documents and simplified the language of the regulation to require operators to maintain documentation demonstrating compliance. Because of the simplified language, AGA's comment regarding ranking threats is moot. Generally, documentation demonstrating compliance will include documentation to show how the operator has fulfilled the requirements of each element of § 192.1007. PHMSA believes this is the type of information to which Florida was referring in its comment.

PHMSA has revised § 192.1005 to eliminate the proposed requirement that operator procedures describe ''the processes'' for developing and implementing its IM program. Although we did not include all of NAPSR's suggestions in the final rule language, we have modified the language so that the section now requires that operators have procedures ''for developing and implementing the required elements.'' Although PHMSA agrees that all procedures should be clearly written so that anyone who has to use them can understand and follow them, we did not include this language in the regulation text.

b. Documentation retention.

Commenters proposed limiting document retention to 10 years or, in a few cases, through the next regulatory audit cycle. Commenters universally considered that these documents would not be of value beyond these near-term periods and noted that resources to maintain such records would take away from those available to operate and maintain the pipelines.

GPTC and one operator suggested that required retention of performance measures be limited to 2 times the program re-evaluation period. They based this on the proposed 10-year retention, which would be twice the mandatory 5-year re-evaluation period. They noted that operators who evaluate their performance measures more frequently would be overly burdened by requirements to keep records beyond their potential useful life.

Iowa suggested deleting the requirements to retain, as records, a written IM plan and a procedure for ranking threats. They maintained that these are not records, per se, but rather are part of plans that are required to be retained by other regulations.

One consultant suggested revising or deleting the term ''must'' from the requirement that an operator must retain records for a specified period. He noted that an operator who retained records for a longer period would be in technical violation of such a requirement.

PHMSA response: PHMSA agrees that the proposed requirements for documentation retention were overly broad. PHMSA concludes that retaining documentation describing changes to an IM plan will be useful for some period, but agrees that these records would be of limited or no use many years after the changes are implemented. PHMSA has revised the final rule to require that operators maintain records demonstrating compliance for 10 years, and that these records must include superseded IM plans.

PHMSA disagrees that the IM plan is not a record. PHMSA considers that superseded IM plans are records—a record of what the IM program consisted of at a particular time. PHMSA does not consider it necessary or appropriate to delete the term ''must'' as recordkeeping is not voluntary. The 10-year retention requirement is a minimum requirement; operators may maintain records for a longer period.

Comment Topic 12: Excess flow valves (EFVs).

A number of comments were made concerning the proposed requirements related to EFVs.

a. EFV in Subpart H.

AGA, APGA, NAPSR, a number of operators and an industry consultant suggested that the requirement to install EFVs be moved to Subpart H rather than remaining a part of IM requirements. Although EFV installation is a PIPES Act requirement, they noted that this is not inherently an IM requirement. In the NPRM, PHMSA proposed to delete from Subpart H the requirement that operators notify customers of the availability of EFVs but to keep the performance standards for EFVs in Subpart H. The commenters consider this separation unnecessary.

AGA, NAPSR and several operators also requested that we clarify that EFVs are not required to be installed on branch service lines. They noted that the PIPES Act mandate addressed service lines to single family residences and that it is impractical to install EFVs on branch service lines.

PHMSA response: PHMSA has relocated the requirement to install EFVs to subpart H. It will now replace § 192.383. PHMSA has included in revised § 192.383 a definition of service line serving a single-family residence. This definition excludes branch service lines, consistent with the intent of our proposal in the NPRM.

b. Installed EFVs as performance measure.

APGA, GPTC, and several operators suggested that the number of EFVs installed should not be treated as a measure of IM effectiveness. This measure relates to the number of new or replaced services and is unrelated to whether IM is effective or not. These commenters generally did not object to collecting the data, only to its apparent treatment as an IM performance measure. One operator suggested that this item simply be added to the annual report. Another suggested not requiring it to be reported at all. A third requested clarification that the number to be reported is the total number of EFVs installed, which they believe to be PHMSA's intent.

PHMSA response: PHMSA agrees that the number of EFVs installed is not a measure of the effectiveness of a distribution IM program. PHMSA expects to need this information to respond to questions from NTSB and Congress (and perhaps other organizations) concerning the implementation of the PIPES Act provision requiring that EFVs be installed. The requirement to include this information in the annual report has been moved to § 192.383. See the comment topic discussing the annual report for more information.

c. Installation criteria.

Connecticut Department of Public Utility Control recommended that the EFV requirement be expanded beyond the PIPES mandate to all situations in which installation of an EFV is technically feasible. One operator suggested that the pressure criterion be revised to specify that the distribution system, rather than the service line, must operate at a minimum of 10 psig throughout the year.

PHMSA response: PHMSA has not made either change. The installation criteria included in the PIPES Act reflect the performance standards that have long been in 49 CFR § 192.381. Most EFVs manufactured in the U.S. comply with these criteria and PHMSA considers them to define, for practical purposes, where installation is feasible. States have the ability to impose additional requirements affecting circumstances not enveloped within the criteria in this rule if they can justify such requirements under state procedures. With respect to the operator's comment, the pressure at the valve location, i.e., in the service line, is the relevant criterion. It does not matter if pressure at some other location in the distribution system is lower than required.

d. Replaced service line definition.

One operator requested that the rule define a replaced service line as a natural gas service line that is entirely replaced, noting that this is consistent with the PIPES Act. GPTC and Iowa suggested that the definition of a replaced line now in § 192.383(a) be moved to § 192.381, since it would be lost with repeal of § 192.383.

Missouri Public Service Commission commented that installation should be required for circumstances other than entire replacement of an existing service line. They contend that the current practice, pursuant to § 192.383, is to require an operator to notify a customer of the availability of an EFV if replacement work provides an opportunity to install an EFV, even if this involves less than replacement of the entire service line. The Commission believes that PHMSA's intent was to require installation in the same circumstances and believes that the language in the proposed rule does not implement that intent.

PHMSA response: We have revised the reference to ''installed or entirely replaced'' to use the defined term ''replaced service line'' to eliminate confusion. PHMSA has retained the definition of replaced service line in the revised § 192.383(a) and requires installation for situations meeting this definition. EFVs, to be effective, are installed at or near the connection to the main. Using the defined term ''replaced service line'' avoids the misunderstanding expressed by the commenter; PHMSA does not intend to mandate additional excavation to install an EFV when another portion of the service line is excavated. The cost of excavation is the significant factor in installing an EFV, and PHMSA considers it appropriate to require installation when the area near the connection to the main has been exposed and an opportunity to install exists. It would not be prudent to forego this opportunity for installation simply because some downstream portion of the service line is not replaced.

e. Master meter/LPG exclusion.

NAPSR and Southwest Gas objected to the proposal's exclusion of master meter and LPG operators from the requirement to install EFVs. They noted that the PIPES mandate did not exclude these operators. They also suggested that these small operators do not have the degree of control over excavations that can cause damage, and thus over the threat that EFVs are intended to mitigate.

PHMSA response: In the NPRM, we requested public comment on whether we should limit the requirements imposed on MM and LPG operators. Although the PIPES Act mandate did not exclude these operators from the EFV installation requirement, we proposed to exclude them from the requirement because we expect few of these lines will meet the threshold performance requirements. Based on the comments we received, we have re-evaluated the proposal and determined they should not be excluded. We agree with commenters that the threshold performance requirements are a better means of excluding some systems than just a blanket exclusion. Thus, in the final rule, we have included master meter and LPG operators among the distribution operators subject to the requirement to install EFVs.

As stated above, we expect that because of the threshold performance standards required for EFV installation, most of these simpler master meter and LPG systems will not meet the threshold and operators of these systems will install few, if any, EFVs as a result of this requirement. For example, many of these systems operate at very low pressures, and the rule provides that EFVs need not be installed where operating pressure is less than 10 psig.

f. Terminology.

One operator suggested that the references to § 192.381 should refer to ''performance standards'' rather than to performance requirements, as that would be more accurate.

PHMSA response: PHMSA agrees and has made this change.

Comment Topic 13: Guidance.

A number of comments addressed guidance available for implementing this rule.

a. PHMSA guidance.

AGA and several operators suggested that the guidance document prepared by PHMSA, and included in the docket, is not necessary. They noted that the GPTC Guidance for integrity management (an appendix to the GPTC Guide) is more complete and will be available separately from the GPTC Guide, at nominal cost. Iowa commented that PHMSA's guide is not useful and that it conflicts with the provisions in the rule concerning leak management. One operator suggested that the PHMSA guidance document contains adequate detail for master meter and LPG operators but that references to requirements for larger operators should be eliminated from it. They commented that the document does not accurately reflect reporting and other requirements for larger operators.

PHMSA response: PHMSA agrees that the GPTC appendix provides more information than PHMSA's draft guidance. PHMSA is concerned, however, that the GPTC appendix will not be useful for most master meter and small LPG operators. Many of these operators will likely not purchase the Guide or the separate appendix. The appendix contains more information than these operators need, and they often lack the technical resources to extract the more-limited information that is important to their operations. PHMSA considers it important to provide guidance focused specifically on the needs of MM/LPG operators and will edit its guidance document to do so. PHMSA will remove other information and defer to the GPTC appendix as guidance for larger operators.

b. GPTC Guide.

GPTC and an industry consultant noted that the preamble stated PHMSA would revise GPTC guidance if needed. They point out that only GPTC can change that guidance.

PHMSA response: The commenters are correct. The statement in the NPRM referred to potential changes PHMSA might make to its own guidance for MM/LPG operators, not to the GPTC guidance.

Comment Topic 14: Leak monitoring.

A large distribution operator suggested that the rule should not require operators to ''implement'' leak monitoring because that implies they do not now have such programs. They suggested that the rule require that operators ''have'' such programs. The operator also suggested that the rule delineate the contents of an effective program.

Several smaller operators suggested that leak monitoring should not be required in this rule at all. They commented that only risk measures indicated as appropriate by risk analysis should be required.

APGA noted that some operators do not monitor leaks; they repair all leaks. APGA contended that these operators should not be required to establish criteria to grade leaks. Operators who do not repair all leaks should have criteria for grading leaks not repaired.

PHMSA response: Leakage is the principal failure mode for low-stress distribution pipelines. Most incidents on distribution pipelines result from the accumulation of gas that has leaked from the pipeline. Section 192.703(c) already requires that hazardous leaks be repaired promptly, but operators may repair leaks at a later time if determined not to be hazardous. PHMSA considers it important that operators monitor these leaks to assure that hazardous conditions do not develop. At the same time, PHMSA recognizes that some operators repair all leaks when found and does not intend to require these operators to develop unnecessary monitoring programs. PHMSA also recognizes that most operators that do not repair all leaks when found already have leak monitoring programs. PHMSA has revised the final rule to require that risk mitigation measures include a leak monitoring program except if all leaks are repaired when found. PHMSA has also modified § 192.1007(e) to clarify that operators who repair all leaks when found do not have to categorize them for hazard for the sole purpose of performance monitoring.

PHMSA does not consider it necessary to delineate the contents of an effective leak management program in the rule. Operators should develop a program based on their knowledge of their pipeline system. The GPTC Guide also offers guidance regarding how to develop an effective leak management program.

Comment Topic 15: State authority.

Florida PSC commented that States must have the authority to review, analyze, and approve or deny an operator's distribution IM program. They contended that the programs will be unique and complex. They noted that evaluation of a program will require judgment and suggested that reaching an agreeable program may require several years.

NAPSR commented that the rule should explicitly recognize the need to include flexibility for States to accommodate their specific circumstances. They noted that this need was recognized explicitly in PHMSA's report to Congress on DIMP.

PHMSA response: Certified state regulators who exercise jurisdiction over intrastate distribution pipeline operators have the authority and obligation to inspect operator compliance with this final rule; however, PHMSA does not require an operator's plan to be approved by the regulatory authority. Regulators must review operator IM programs and direct changes in cases in which they determine that the operator's program does not comply with the rule. PHMSA recognizes that IM programs will be unique and can be complicated (reflecting complexity in some distribution systems) and that these programs will likely take several years to reach maturity. As noted earlier, PHMSA plans to develop and provide training and qualification programs for state inspectors. PHMSA intends to provide states with background information necessary for them to conduct reviews and to avoid large inconsistencies in the approach to IM across the country.

PHMSA's statements in this rulemaking record have consistently recognized that states must have the flexibility to address their specific circumstances. Nothing in the language of the rule restricts this flexibility. PHMSA understands that operator IM programs will vary based on differences in their pipelines and operations and that states need to consider each program on its merits. The rule establishes high-level requirements but leaves operators and their regulators (mostly states) to determine how best to do it in each individual circumstance.

Comment Topic 16: IM program evaluation and improvement.

A number of comments addressed proposed requirements to evaluate and improve distribution IM programs.

a. Continual evaluation.

APGA, Iowa, and a number of operators objected to the proposed requirement in § 192.1007(f) that an operator ''must continually re-evaluate threats and risks on its entire system.'' These commenters suggested that such re-evaluation be required on a periodic basis. They noted that continuous re-evaluation is unreasonable and that it doesn't follow from the concept of ''periodic evaluation and improvement'' (the title of this proposed paragraph).

PHMSA response: PHMSA considers that operators should evaluate the effectiveness of their IM programs on a routine basis, i.e., ''continually.'' That is a basic concept of an effective IM program that has been used in other IM regulations. Nonetheless, because of the overwhelming concern raised by commenters about this term, PHMSA has revised the final rule to require that such re-evaluations occur on a periodic basis, based on the complexity of the system and changes in factors affecting the risk of failure; however, re-evaluations must occur at least once every 5 years.

b. Continuous improvement.

One operator noted that making changes solely to show ''improvement'' can be disruptive and ultimately detrimental to performance.

PHMSA response: Continuous improvement is an important part of the philosophy underlying IM. Where evaluation of an IM program identifies changes that can improve the program's effectiveness, these changes should be incorporated into the program. The ultimate goal is to improve safety. Improvement cannot be realized without change.

c. Evaluation frequency.

NAPSR objected to the proposed requirement that operators must determine the appropriate period for conducting complete program evaluations based on the complexity of their systems and changes in factors affecting the risk of failure and that the interval selected may not exceed five years. NAPSR suggested that an evaluation be required annually (not to exceed 15 months), similar to the evaluation interval for other programs required by Part 192. NAPSR believes that five years is too long, noting that the stakeholder conclusion was that an annual review should be required.

PHMSA response: An operator should re-evaluate its IM program whenever changes occur in the system that may result in new knowledge, new threats or other information that would permit improvement in the IM program. For some operators, this may be more frequent than an annual basis. For other operators, these types of changes may occur seldomly. Therefore, we are retaining the requirement for all operators to evaluate their program at a period appropriate for their system and at least every five years, as proposed in the NPRM.

d. Required improvement at specific frequency.

Several operators objected to the proposed requirement to periodically improve each IM element in § 192.1005(b) (as well as the requirement to continually refine and improve in proposed § 192.1007(a)(4)). They maintained it may not be reasonable to ''improve'' all elements at all times, and that enforcement of such a requirement would pose problems. They suggested that the proposed requirements to ''improve'' be replaced with a requirement to review and adjust/update as needed to meet distribution IM goals. One operator read proposed § 192.1007(d) to require that operators implement new mitigation measures annually and requested we clarify that this is not required.

PHMSA response: PHMSA's intent was to encourage operators to consider potential improvements to their IM programs routinely as a regular part of their activities. To improve clarity, PHMSA has revised the final rule to require that programs be reviewed on a periodic basis and improved as needed. Section 192.1007(d) requires that operators determine and implement measures to reduce risks. Section 192.1007(f) requires that operators reassess their programs periodically, but at least every five years. Nothing in the rule requires that new mitigation measures be implemented at any periodicity.

e. Redundant requirements.

One operator suggested we delete the proposed requirement in § 192.1005(b) that operators have procedures for ''periodically improving each of the required elements''. The operator noted that periodic evaluation and improvement is, itself, an element, and that this makes the proposed requirement in § 192.1005(b) confusing, at best.

PHMSA response: PHMSA agrees and has revised the final rule. We have revised section 192.1005 to specify that an operator must develop and implement a written IM program that addresses the required elements in § 192.1007. Section 192.1007 now provides that the IM plan must have procedures to develop and implement the required elements. One of the required elements is to refine and improve the program as needed (section 192.1007(a)(4)).

f. Consideration of threats in re-evaluation.

Another operator suggested that PHMSA delete the requirement in proposed § 192.1007(f) that an operator ''consider the relevance of threats in one location to other areas'' as part of its periodic re-evaluation. This operator contended that this is covered by the requirement in proposed § 192.1007(c) that threats be considered in all areas.

PHMSA response: PHMSA recognizes that a thorough evaluation of threats in any area should identify threats of concern regardless of whether they affect other areas of an operator's system. Still, PHMSA considers that knowledge that a threat affects a system in one location, and how that threat manifests itself, can inform consideration of that threat in other locations. PHMSA has retained this requirement in the final rule.

Comment Topic 17: Permanent marking of plastic pipe.

The NPRM preamble posed a number of questions concerning permanent marking of plastic pipe. These questions elicited a number of responses.

a. Support for marking

One operator strongly supported requirements to mark plastic pipe, providing a list of attributes the operator believes should be marked every 18 inches.

b. Against marking

AGA, supported by at least one operator, suggested that plastic pipe marking should be considered outside of DIMP. Both maintained that manufacturer input is needed on this subject and that most operators do not possess the data infrastructure to record and properly manage data from each piece of plastic pipe. They contended that the knowledge requirements of proposed § 192.1007(a) are sufficient to manage pipeline integrity.

Several operators suggested that ASTM should address pipe marking and that PHMSA should not establish requirements in this area. Some operators, GPTC, Iowa and one plastic pipe consulting company noted that the current version of ASTM D2513, which is not yet referenced in Part 192, includes permanent marking requirements. Some operators noted that fittings are a separate concern and suggested that they would present other problems/considerations.

PHMSA response: We did not propose a requirement to mark plastic pipe. Rather, we asked for comment to elicit better information about various pipe types and their performance history. PHMSA believes operators may be able to better manage risk with better information regarding pipe performance. We plan to address this issue outside this rulemaking.

Comment Topic 18: Continuing surveillance.

Iowa and a large operator suggested that we revise § 192.613, Continuing surveillance, to exclude distribution systems subject to proposed new Subpart P because it will be a redundant and unnecessary requirement if DIMP is implemented as proposed.

PHMSA response: PHMSA disagrees. While some aspects of IM may overlap activities operators perform as part of continuing surveillance, there are requirements in § 192.613 that are not duplicated in this rule. For example, DIMP does not specifically require an operator to recondition or phase out an unsatisfactory segment when no immediate hazard exists.

Comment Topic 19: Information gathering.

The NPRM proposed (§ 192.1007(a)) that an operator must demonstrate an understanding of the gas distribution system. NAPSR suggested that the proposed rule should require operators to assemble information about their systems that is ''reasonably available.'' NAPSR maintained that it is unreasonable to suggest operators should develop the best understanding possible. NAPSR further maintained that the proposed language fails to list useful sources of information and implies an unbounded need for knowledge. NAPSR would revise the language to more completely identify the sources of information to be used and would limit the requirement to identify system characteristics and environmental factors (proposed sub-paragraph (a)(1)) to those ''reasonably'' necessary to assess threats and risks.

PHMSA response: PHMSA understands NAPSR's concern. PHMSA does not intend that operators expend excessive effort, review every record available in their archives, or explore every nuance about their pipelines. At the same time, PHMSA expects that operators will devote sufficient effort to develop as thorough an understanding of their pipelines as they can while using reasonable effort. PHMSA has revised the final rule to require that operators develop an understanding of their pipeline systems ''from reasonably available information.'' PHMSA considers that this strikes the appropriate balance. Because of this change, PHMSA does not consider it necessary to modify subparagraph (a)(1) to limit information to assess threats and risk to ''reasonably'' necessary information.

PHMSA has not included in the rule a list of information that operators should use to find information about their pipeline systems. An operator is in the best position to determine what information is most relevant to its system. PHMSA is concerned that any such list would become limiting (i.e., operators and regulators would not consider sources not included in the list) or would create unnecessary burdens (e.g., a perceived obligation to review a source listed even though it would not reveal useful information).

Comment Topic 20: Knowledge of pipeline.

PHMSA also received other comments regarding the need for an operator to know its pipeline:

a. Environmental factors.

APGA, GPTC, and a large operator suggested that we clarify ''environmental factors'' in § 192.1007(a)(1) to mean factors (*e.g.,* washouts, landslides) that could pose a hazard to the pipe as opposed to factors that would make the environmental consequences of accidents worse. They noted that gas does not produce significant environmental consequences as would oil or other hazardous liquids.

PHMSA response: PHMSA concludes that no change is needed. This paragraph already refers to ''environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline'' and does not refer to consequences. PHMSA notes that washouts and landslides are extreme examples of ''environmental factors'' that might be of concern. Other environmental factors that might need to be considered include soil corrosivity or location in an area likely to experience a greater-than-normal amount of excavation activity.

b. Normal activities.

One large operator suggested that the ''normal activities'' through which operators are expected to glean additional knowledge (proposed 192.1007(a)(3)) be specifically limited to, ''normal activities performed in the construction, operations, and maintenance of gas distribution systems in accordance with the applicable requirements of Part 192.''

PHMSA response: PHMSA does not consider this limitation necessary. Operators are expected to take advantage of opportunities to improve system knowledge through any of their normal activities, including those that go beyond those activities specifically required by Part 192. For example, excavation that exposes the pipeline system presents a significant opportunity to learn additional information, but few excavations are conducted specifically to comply with Part 192 provisions.

c. Additional activities.

PA PUC would expand the list of activities through which operators are expected to gain additional knowledge to include maintenance and management policies in addition to past design and operations (§ 192.1007(a)(2)). They would revise proposed § 192.1007(a)(4) to replace the requirement to ''continually'' refine and improve knowledge with a requirement to ''develop an ongoing process by which the operator's knowledge of its system will be refined and improved.''

PHMSA response: PHMSA's use of ''operations'' in this context was intended in its broadest sense—activities associated with operating the system, including maintenance. This comment indicates that it is possible to read the proposed language as excluding maintenance. PHMSA has modified the final rule to reflect that information gained from operations and maintenance should be considered. PHMSA considers the phrase ''management policies'' to be vague and subject to misunderstanding and has not included it in the final rule. Changes associated with eliminating the implication that operators must ''continually'' improve their knowledge have been described above.

d. Design and operations information.

One operator would delete proposed paragraph (a)(2), which would require that an operator understand the information gained from past design and operations, because it is unclear how compliance can be achieved or demonstrated. Another operator would add ''design and operations'' to the requirement in proposed paragraph (a)(1) to understand the system.

PHMSA response: PHMSA has revised paragraph 192.1007(a)(2) to require that operators consider lessons from past design and operation experience, rather than that they ''understand'' them. For example, operators could involve maintenance foremen/supervisors in their information collection activities, surveying them to ask about unusual circumstances they have encountered in their activities and/or asking them to review resulting system descriptions and identify any information they believe useful that is not already included. Good information only has an effect when it is used. Compliance will be reviewed by assuring that an operator has implemented means to gather this information and has considered the information.

e. Terminology.

An operator would change ''piping system'' and ''piping and appurtenances'' in paragraph (a)(5) to ''pipeline'' for consistency with the definition of pipeline in § 192.3.

PHMSA response: PHMSA has made the suggested change.

Comment Topic 21: Threat identification.

Several changes were suggested to the proposed requirement for operators to identify threats in § 192.1007(b). Paragraph (b) listed categories of threats and potential sources of information an operator must consider.

a. Data sources.

APGA would delete reference to ''one call experience'' because the meaning of this term is unclear and would add nothing beyond the operator's own damage experience. One operator would limit ''incident history'' as a data source to incidents requiring reporting per § 191.3. Another operator suggested that the list of threats be revised to match the list in the annual report, noting that there are minor inconsistencies in the wording of the proposed requirement. An operator suggested that ''and any other concerns that could threaten the integrity of the pipeline'' is unlimited and thus unreasonable.

PHMSA response: Because relevant information from one call experience would overlap with the operator's own excavation damage experience, PHMSA agrees that listing one-call as a source of information for threat identification is redundant and has made the suggested change. The term incident, as used in the regulations, is commonly understood to refer to incidents as defined in § 191.3. The list of categories in this final rule is consistent with the categories in the annual report. What minor wording inconsistencies exist are due to use of the list in a sentence structure in the rule. PHMSA considers the language regarding ''any other concerns'' to be consistent with the ''other'' category of threats on the annual report form.

b. Sources of information.

NAPSR and Iowa contended that the proposed language unnecessarily restricts sources of information an operator may use (i.e., ''An operator must gather information from the following sources''). Instead, NAPSR would require that an operator consider sufficient data to identify existing and potential threats and would identify the proposed list as sources an operator ''may include, as appropriate.''

PHMSA response: PHMSA agrees and has revised the paragraph to clarify that the information sources an operator must use to identify threats are not limited to those listed.

c. Third party damage.

A consultant noted that the threat of third-party damage should not be as significant for small operators as for large because small operators exercise better control and/or it is easier to patrol their systems. At the same time, he noted that his own analyses of small systems (i.e., master meter) suggests that threats other than third-party damage may be as significant or more significant for small operators than for large.

PHMSA response: Each operator will be required to determine the relative importance of threats for its distribution pipeline as part of implementing this final rule. An operator will be able to factor in the degree of control it has over its system when determining the relative importance of threats. We have not revised the language in the final rule.

Comment Topic 22: Risk assessments.

Several comments addressed the proposed requirements for risk assessment in § 192.1007(c).

a. Subdividing a pipeline for risk analysis.

NAPSR and one operator commented that subdivision of a distribution system for risk analysis may not be geographical, as they believe the proposed language implied. They noted that similarity of characteristics and environment may be more important factors for subdividing analyses than location. The operator suggested that class location might be an appropriate factor. Other operators suggested that the concept of ''regions'' for analysis is not clear and commented that the suggestion for grouping by consistent risk or actions be eliminated; they noted that one cannot group by common risk without analyzing risk first and that suggesting otherwise results in circular logic.

PHMSA response: PHMSA agrees that subdividing a distribution pipeline system for risk analysis could be done on a basis other than geography. PHMSA has modified the final rule to clarify that geographic proximity is only an example of how a region may be defined, by inserting ''e.g.,'' before this description and by adding another example. PHMSA agrees that the concept of creating regions for risk analysis on the basis of reasonably consistent risk results is circular logic and has deleted this criterion.

b. Evaluate threats.

One operator suggested that the requirement to evaluate threats as part of the risk assessment be limited to known threats because it is impossible to rank the importance of ''potential'' threats.

PHMSA response: PHMSA disagrees. In many cases, ''known threats'' are treated as threats that have resulted in an effect on the pipeline, while other threats are, at best, ''potential.'' For example, earth movement might not be considered a ''known threat'' for pipe located in an area where landslides can be expected but where the pipeline has never been affected by one. It would be important, though, to consider the likelihood that the ''potential'' threat of earth movement might affect this pipe as part of an operator's IM program. It should also be possible to collect information about the relative likelihood of a landslide to consider this threat, including ranking its importance and determining whether mitigative actions are appropriate. PHMSA has retained the requirement to consider potential threats in the final rule.

c. Defining terms.

One operator suggested that the term ''relative probability'' should be defined. Another operator suggested that the term ''probability'' be replaced with ''likelihood'' throughout the proposed rule, to eliminate the implication a rigorous mathematical process is required.

PHMSA response: PHMSA agrees that use of the terms ''probability,'' ''relative probability,'' and ''prioritize'' could imply a need for a mathematical process. PHMSA has noted confusion about the need for quantified estimates of risk throughout the discussions related to distribution integrity management. For complex systems where there is a wealth of data, a mathematical analysis of risk may be the best way to understand the relative importance of various threats. For most distribution pipeline systems, however, simpler techniques (as described in the GPTC Guide, for example) should suffice. PHMSA has revised the final rule, to avoid further confusion, to replace these terms with ''importance,'' ''relative importance,'' and ''rank.'' One useful reference tool could be the GPTC Guide for guidance on non-mathematical methods of evaluating risk.

d. Prioritize risk.

One operator suggested that the requirement to estimate or prioritize risk should be eliminated, and that the requirement be limited to determining the relative probability of threats. The operator contended that each pipe material carries its own threats, and that it is difficult to prioritize one over another. Prioritization is too difficult and may not meet the intended purpose because there is often insufficient data to quantify.

PHMSA response: PHMSA disagrees with eliminating a requirement to prioritize risk. Prioritizing actions is an inherent part of managing any activity. It is needed to apply limited resources where they will do the most good. With respect to IM, PHMSA firmly believes that this prioritization should consider risk, i.e., both likelihood and consequences. For example, an operator may face two threats that can produce different consequences. It would be inappropriate to apply resources to the threat with a slightly higher likelihood of occurrence and not to the second threat if the consequences that could result from the second threat are much greater. The risk (*i.e.,* likelihood and consequences) of the second threat is higher.

PHMSA understands that it is easier to rank threats when only a single variable changes, and that limiting consideration to threat ranking by material would be easier. This would not, however, assure the most effective application of safety resources, which an operator must apply across its entire pipeline, regardless of differences in the material of construction.

Comment Topic 23: Performance measures.

A number of comments were made concerning proposed requirements for performance measures. In the NPRM, PHMSA proposed that an operator must develop and monitor performance measures to evaluate the effectiveness of its IM program and required the performance measures to include the number of hazardous leaks, categorized by cause and by materials, number of excavation damages, the number of excavation tickets, the number of EFVs installed, and the total number of leaks categorized by cause. The proposal required an operator to develop additional measures necessary to evaluate the effectiveness of controlling each identified threat.

a. NAPSR suggested an additional performance measure, which could be derived from data already reported: the amount or ratio of non-state-of-the-art pipe in an operator's system.

PHMSA response: PHMSA does not agree that this is an appropriate national measure. This measure was considered in the work of the stakeholder groups. The final report of that work did not recommend this as a national performance measure.[9] One reason for this conclusion was that it could be misleading. Much older pipe (*e.g.,* cast iron) that has been properly maintained operates quite safely. At the same time, problems have sometimes been experienced with new pipe (*e.g.,* specific heats of plastic pipe). PHMSA recognizes that many states are working with their operators to support pipe replacement programs intended to replace non-state-of-the-art pipe, and PHMSA encourages those efforts. PHMSA expects that the states will monitor the amount of non-state-of-the-art pipe remaining in an individual operator's system as part of such replacement programs. Reporting this parameter on a national basis is not needed to facilitate required pipe replacement programs.

b. The proposed performance measures included the number of hazardous leaks eliminated or repaired and the number of excavation tickets. A consultant suggested the need for more precise definitions of ''ticket'' and ''leak'' as the use of these terms is imprecise across the industry. Two operators agreed that a definition of excavation ticket is needed. Another suggested that this be limited to ''tickets received from the notification center where marking is required.'' Another suggested that PHMSA should not define this term.

An operator suggested that damages should be normalized per 100 tickets. The operator noted that differing levels of construction activity could imply that an operator's IM program is more, or less, effective but that this is totally outside the operator's control. Another operator suggested that the number of excavation tickets has no value as a performance measure, and that this data is expensive to generate. This operator explained that tickets are often issued for areas in which there is no gas pipe in the vicinity of planned excavation and that tickets may be renewed. These operators also suggested that tickets are issued for areas of differing size. They contended that, because of all of these differences, this data is not useful to normalize excavation damage information.

PHMSA response: The purpose of the measure to report the number of excavation tickets is to normalize excavation damage information in order, for example, to help determine whether reduced excavation damages are a result of improved damage prevention programs or less construction (excavation) activity. Normalization is necessary precisely for the reason identified by the commenters—changes in the amount of construction activity will affect the number of excavation damages but are outside the control of an operator's IM program. PHMSA expects that analyses will likely normalize per 100 tickets but notes that this is a simple arithmetic adjustment if the basic data is available. Operators are required to participate in one-call programs to receive notification of planned excavation activity, i.e., tickets.[10] PHMSA thus concludes that collecting this data will not be expensive. Reporting of this parameter has thus been retained in the final rule.

Differences in how tickets are treated and in the definition of ''ticket'' among various state one-call programs were discussed during the stakeholders' work preceding the proposed rule. The groups noted that this term is defined somewhat differently by various state one-call programs, and that these differences could cause inconsistencies in data reported to PHMSA. At the same time, the groups noted that considerable additional effort could be required for operators to track tickets in two ways—one matching their one-call program definition and one matching a common national definition. The stakeholder groups concluded that this data could serve its purpose even if there were some inconsistency in the data reported to PHMSA and that the additional burden involved for some operators using two definitions was not justified. PHMSA agrees. The final rule clarifies, as did the proposal, that what is meant by a ''ticket'' is receipt by the operator of information from the notification center, regardless of the criteria the center uses to decide when notifications should be made.

Leaks have been reported on the annual report required of distribution operators for many years. The instructions for completing the annual report define a leak as the unintentional release of gas from a pipeline. PHMSA is not aware of any difficulties or confusion in reporting leaks, and does not consider that a definition need be added to this rule.

c. A consultant suggested that the requirement for operators to measure performance should be deleted. Alternatively, PHMSA should evaluate incidents against program effectiveness. The consultant believes that individual operators cannot generate enough data for meaningful analysis and that problems inherent in performing statistical analysis of small numbers and luck, both good and bad, would likely obscure meaningful information from an operator's performance analyses. Two commenters suggested that the performance measures requirement be eliminated. An operator suggested that the rule should simply require that

[9] PHMSA, ''Integrity Management for Gas Distribution: Report of Phase 1 Investigations,'' December 2005, page 16.

[10] 49 Code of Federal Regulations, Section 192.614(b).

operators have appropriate measures. Iowa suggested that the requirements are not needed if the annual report forms are modified to include the desired information.

The NPRM preamble noted that a reduction of incidents will be the ultimate indicator of performance, but that it will take years to see trends in this data. The NPRM stated that the proposed performance measures would provide a measurement during the interim period while these trends are developing and invited the public to suggest other measures for this interim period. In response, one operator commented that there should be no interim measures, only permanent. Another operator, apparently reflecting the same concern about potential changes in reporting requirements, suggested that performance measures, once in place, should remain stable for at least 5 years. The operators noted that time is needed to determine the effectiveness of such measures and to implement data system changes and personnel training.

PHMSA response: Measuring performance is a key element of all integrity management programs. IM rules for other types of pipelines also include this element. At its basic level, IM is an iterative process consisting of analysis of risks, implementing actions to reduce risk, monitoring to evaluate the effectiveness of those actions, and modifying the program as needed. Without performance monitoring, the feedback portion of the process cannot occur.

On a macro basis, PHMSA agrees that the number of incidents is the ultimate measure of the effectiveness of efforts to assure distribution safety. PHMSA will continue to collect incident data and will use that data to evaluate the effectiveness of its regulatory program. This measure is not useful to individual operators, however, precisely because the number of incidents is small. Many operators will experience no incidents in a year. Few, if any, will experience more than one. Operators must use other non-incident measures to evaluate the effectiveness of their own programs. PHMSA continues to conclude that it is appropriate that the rule require these actions.

As discussed in the NPRM, it will take several years for incident data to indicate any trend as a result of the actions required by this rule. PHMSA considers it necessary to collect additional performance measures to permit preliminary judgments concerning the effectiveness of this regulation in the interim. This does not mean that these measures are not ''permanent.'' The final rule retains the requirement to submit performance measures in the annual report.

d. A citizens group commented that key information, such as hazardous leaks repaired by cause and material, must be publicly available. NAPSR and the Pennsylvania PSC also suggested that data reported to PHMSA should be in a database accessible to states, rather than requiring duplicate reporting. The Arizona Corporation Commission, taking a contrary position, suggested that reports sent to PHMSA should also be required to be submitted to States exercising jurisdiction.

PHMSA response: All IM performance measures submitted to PHMSA will be part of the annual report filed by distribution pipeline operators. Annual report information is available to the public via the PHMSA web site. In addition, we are requiring operators to report performance measure information to states exercising jurisdiction.

e. NAPSR and Iowa suggested that the number of leaks repaired/replaced by material be added as a national performance measure, as this is useful information relevant to the effectiveness of IM. These commenters also suggested that the requirement to report information concerning leaks be limited to information that is known or available. They noted that operators may not excavate leaking pipe, but may replace it and retire leaking sections in place. In that instance, they may not know the cause of the leak, or the particular material on which it occurred (*e.g.,* whether on pipe body or a valve/fitting).

PHMSA response: The stakeholder groups considered the use of leaks-by-material as a national performance measure but rejected it as a measure in part because of the potential for misinterpretation. Many leaks are caused by excavation damage or other outside forces, in which case the pipe material is not of principal importance. The groups concluded that this would be useful information for operators in evaluating the effectiveness of their own programs but that it should not be reported on a national basis. PHMSA agrees.

PHMSA notes that operators have been required to report the number of leaks eliminated/repaired, by cause, for many years as part of their annual reports. Operators have presumably filed these reports based on the information that they have available. PHMSA is not aware of complaints that unnecessary effort has been required simply to determine a cause for reporting purposes. PHMSA therefore does not consider that any explicit limitation is necessary on the information to be used to identify the cause of repaired leaks.

f. An operator suggested that specific causes to which leaks are to be attributed should be listed, and further that the list of causes must include ''unknown.'' The operator suggested that meaningful comparisons require a limited number of specified causes. The operator also noted that lines are often retired in place rather than being removed, and that the cause of leaks is thus not always known.

PHMSA response: Performance reporting will be via the annual report. The annual report currently requires that operators report leaks repaired by cause. It lists a number of causes for this purpose, including ''other.'' Any revisions to the form for purposes of IM performance measures will similarly provide a list of causes. See the annual report comment topic for more information regarding changes to the annual reporting form.

g. NAPSR, Iowa, and one operator suggested that we clarify ''any additional measures'' described in proposed § 192.1007(e)(1)(vii) are additional measures the operator selects.

PHMSA response: PHMSA has made this clarification.

h. One operator suggested that PHMSA should establish guidance for implementing uniform metrics, since these are needed for a performance-based process.

PHMSA response: PHMSA will use four measures to evaluate the overall effectiveness of this regulation. These measures are specified in this rule, will be listed on the revised annual report form, and will be in the instructions for completing the annual report. As discussed above, PHMSA expects that there will be some inconsistencies in reporting of at least one measure (number of excavation tickets); however, the data submitted with the annual report will be sufficient for PHMSA to evaluate the effectiveness of the regulation.

PHMSA does not consider that further guidance is necessary to assure that operators are collecting other performance measure data uniformly, as that data will be used by individual operators to evaluate the effectiveness of their programs. An individual operator should collect and use the data it collects consistently; however, differences between operators do not matter.

Comment Topic 24: Regulatory analysis.

We received a number of comments concerning the regulatory analysis supporting the proposed rule: In response to a question about whether the proposed performance measures were burdensome, two commenters stated they were not. Other commenters raised specific issues regarding the regulatory analysis.

a. Assumptions used in the analysis.

NAPSR, AGA, an operator association, and an individual operator commented that assumptions made in the analysis are not supported. In particular, the assumption that implementing the proposed rule will result in a 50 percent reduction in incidents, which is key to the analysis of the benefits of the proposal, appears to have no foundation.

PHMSA response: It is not possible to determine precisely the effectiveness of a new regulation before it is implemented. It is therefore necessary to make assumptions for purposes of analysis. The analysis then includes an evaluation of the sensitivity of its conclusions to those assumptions. Here, PHMSA expects that the regulation will help ensure the integrity of distribution pipelines and will reduce the number and severity of incidents that occur on these pipelines. An assumption of a 20 percent to 50 percent reduction in incidents was made for purposes of analysis, but that assumption is not critical to the conclusions. The final regulatory impact analysis demonstrates,[11] in fact, that societal costs associated with gas distribution need only be reduced by about 12.2 percent in the first year and 9.5 percent in successive years for the rule to yield positive net benefits.

b. Lost gas.

AGA and an operator noted that assumptions concerning lost gas are not supported. They refer to the stakeholder report where the difficulties of measuring lost gas are discussed. That report states that reported ‘‘lost gas’’ often reflects measurement uncertainties rather than actual losses.

PHMSA response: Whether the amount of lost gas can be measured with accuracy does not affect whether gas is actually lost. PHMSA understands that the amount of lost gas reported may depend as much on measurement uncertainties as on actual losses, but concludes that actual loss does occur. This rule will have the effect of improving leak management, and damage prevention. The requirement that excess flow valves be installed will reduce the amount of gas released if a service line is damaged by excavation. All of these actions will reduce the amount of gas lost. PHMSA has relied on information from the EPA for its assumptions concerning lost gas, and considers that the estimated reduction of 10 percent cited in the regulatory impact analysis is reasonable.

c. Competitive market.

AGA, an operator association, and an operator disagreed with our conclusion that local gas distribution is not a competitive market. They noted that utility commissions consider all market forces and that some States have deregulated this function.

PHMSA response: PHMSA recognizes that utility regulatory commissions consider market forces in their rate regulating activities and that some aspects of natural gas supply have been deregulated in some States. Nevertheless, distribution of natural gas has not been completely deregulated in any areas of which PHMSA is aware—i.e., a customer does not have a choice of multiple suppliers for natural gas delivered to its residence or place of business. Thus, PHMSA considers that the statement made was accurate. It did not affect the conclusions of the analysis.

d. Cost effective.

FL PSC suggested that the proposal is not cost effective, noted that recent regulatory extensions have been extensive, and suggested we review the current regulations, in total, before proposing more. They pointed to a rate case in which a company is requesting $750,000 to implement distribution IM for a system containing 10,000 miles of distribution mains, and that applying the unit rate to the total mileage of distribution mains in the U.S. would result in an estimated implementation cost of nearly $84 million. This would equate to more than $3.8 million per death averted if all deaths resulting from accidents on distribution systems could be eliminated, which they contend is not a practical assumption. FL PSC also commented that State regulators are overburdened and cannot do more than they are now.

PHMSA response: It is unclear what basis an operator would have used for a rate case addressing implementation of distribution IM at the time of the NPRM, since requirements for that purpose were not final. This final rule makes significant changes from the NPRM, most of which will have the effect of reducing costs. PHMSA has analyzed the costs and benefits that are expected to result from this final rule and has concluded that the rule is cost-beneficial.

PHMSA recognizes that State regulatory programs will be required to undertake new work as a result of this rule. PHMSA supports State pipeline safety programs through grants and is increasing the level of that support. States exercise regulatory authority over intrastate pipelines once they are certified by PHMSA to do so.

e. Burden hour estimate.

A consultant noted that the estimate in the regulatory analysis of ¼ hour for master meter operators to update their programs is unrealistic. He believes that 4 hours is a better estimate for such an update.

PHMSA response: The regulatory analysis and the paperwork reduction act burdens have been recalculated based on comments to the NPRM. PHMSA has revised the estimate to twelve hours per year for master meter operators to update their programs.

Comment Topic 25: IM for new pipelines.

The Missouri Public Service Commission noted that the proposed rule provides many requirements to address the integrity of existing distribution pipeline systems but is silent on the need to assure integrity for new installations. Missouri suggested the rule address how well a pipeline system is built/constructed/installed, which is critical to its integrity. Missouri also suggested adding increased inspection requirements for contractors performing new installations to assure the integrity of new pipelines being installed, and to not install pipelines today that will create integrity issues in the future.

PHMSA response: PHMSA agrees that good installation/construction is important to assuring pipeline integrity. This proposal, however, deals with assuring the integrity of existing pipeline systems. Construction is addressed by other regulations for which changes were not proposed as part of this rulemaking. PHMSA may consider changes to construction regulations as part of future rulemaking activities.

Comment Topic 26: Annual report form.

One operator suggested that PHMSA should develop its reporting forms by working in conjunction with AGA and APGA.

PHMSA response: All data required to be reported will be reported via the annual report. PHMSA has revised the annual report form using its normal procedure, which included consultation with the trade associations.

This final rule requires operators to report four integrity management performance measures as part of the annual report. The rule also requires operators to report, as part of the annual report, detailed information regarding

[11] Final Regulatory Impact Analysis, ‘‘Summary and Conclusions’’, p. 61.

compression coupling failures. One of the performance measures—total number of leaks eliminated or repaired, categorized by cause—is already a part of the annual report form; however, the other information to be reported will require modifications to the annual report form. Therefore, PHMSA is issuing, in conjunction with this rulemaking, a 60-day notice to modify the annual report information collection, OMB Control Number 2137–0522. PHMSA seeks comment on the proposed modified annual report form.

III. National Transportation Safety Board

The National Transportation Safety Board (NTSB) is an independent agency that investigates major transportation accidents, including those occurring on pipelines. The NTSB makes recommendations to PHMSA when it concludes from investigation of pipeline accidents that additional regulatory actions would be appropriate to improve safety.

The NTSB submitted comments on this rulemaking on November 19, 2008. The NTSB supported the approach to distribution IM being taken by PHMSA and stated that ''overall, the NPRM provides a reasonable and logical approach that operators of distribution pipelines can use to develop and implement integrity management plans.'' The NTSB also identified three areas in which they concluded the proposed rule should be improved.

The NTSB considers that an effective leak management program, as required in this rule, must provide for use of equipment that prevents or mitigates leaks. The Board sees EFVs as equipment that should be used for this purpose. The NTSB acknowledges that the proposed rule's requirements for installation of EFVs implement the mandate in the PIPES Act of 2006, but considers that it should go farther. The NTSB recommends that the rule require the installation of EFVs on all new and replaced customer service lines, regardless of customer classification. This would include multi-family dwellings (*e.g.,* apartment buildings) and commercial properties. This is consistent with a recommendation the NTSB made in 2001 following investigation of a pipeline accident.

We have considered requirements for installation of EFVs for many years. PHMSA has conducted two cost-benefit studies. These studies reached contrary conclusions on whether a requirement to install EFVs was cost beneficial and demonstrated that the conclusion on whether EFV installation is cost-beneficial is highly sensitive to the assumptions and data used in the analysis. The PIPES Act required that PHMSA include in this final rule a requirement to install EFVs on new and replaced service lines serving single-family residences. This addresses the vast majority of gas distribution service lines, and this requirement has been included in this final rule. PHMSA has not studied separately the required installation of EFVs on properties other than single-family residences and is uncertain whether such a requirement can be justified on a cost-benefit basis.

The arguments for installing EFVs are that they are effective in preventing accidents caused by significant damage to a downstream service line and that they are inexpensive to install (when the line is newly installed or excavated for other reasons). The contrary argument is that an EFV protects only the service line in which it is installed and incidents causing significant damage to a service line are rare. Thus, a large number of EFVs must be installed, at a large cumulative expense, before one can say with confidence that it is likely that the presence of the installed valves will prevent an accident.

The potential consequences of accidents involving service line damage at multi-family or commercial properties are likely larger than those that would result from accidents on a service line serving a single-family residence. The likelihood that an individual service line would be damaged remains, however, small, and the likelihood that an EFV would prevent an accident at an individual installation is correspondingly small. There are far fewer multi-family and commercial properties than there are single-family residences. This could reduce the likelihood that an EFV would be expected to prevent an accident at such a property so that a cost-benefit analysis would conclude that requiring installation of the valves is not justified. Before imposing such a requirement, PHMSA would need to collect data from manufacturers of larger EFVs and from operators who currently install such valves and conduct a detailed cost-benefit analysis. These actions have not been completed, and PHMSA has not expanded the requirement in this final rule beyond the mandate in the PIPES Act.

The NTSB also recommended that the final rule be revised to address more explicitly the risks from compression couplings. The Board noted that it has investigated a number of accidents caused by pipe pulling out of compression couplings, and that several states have taken actions to require replacement or other actions to assure that compression coupling joints are safe. The NTSB recommended that the rule include specific guidance on how to identify and address problem compression couplings.

PHMSA agrees that there are reasons for concern regarding compression couplings. PHMSA issued an advisory bulletin on this subject on February 28, 2008. The NTSB acknowledged that this bulletin should help utilities identify future problems, but expressed concern that it is only advisory and that operators are not required to implement its suggestions.

PHMSA will encourage GPTC to review its guidance with respect to compression couplings and to improve that guidance, if needed. PHMSA has revised this final rule to require that operators report information on coupling failures as part of their annual report to PHMSA (see comment topic 1 above). PHMSA will consider the data from these reports to decide whether additional requirements relative to compression couplings are warranted. Any additional requirements related to compression couplings would be outside the scope of the proposed rule.

Finally, the NTSB recommended that the rule include specific requirements that operators address risks from directional drilling. PHMSA has not made this change for the same reasons as described above for compression couplings. Directional drilling is a type of excavation damage, a threat category operators are required to consider. We expect that GPTC will provide guidance on considering the threat of directional drilling.

IV. Advisory Committee

On December 12, 2008, PHMSA discussed the proposed rule with the Technical Pipeline Safety Standards Committee (TPSSC). The TPSSC is a statutorily mandated advisory committee that advises PHMSA about the technical feasibility, reasonableness and cost-effectiveness of its proposed regulations. PHMSA discussed some of the key comments received in response to the NPRM, *e.g.,* burdensome documentation requirements, performance through people, plastic pipe failure reporting and excess flow valves. These comments have been previously discussed in this document.

After careful consideration, the TPSSC voted unanimously to find the NPRM (with proposed changes as discussed at the meeting) and supporting regulatory evaluation technically feasible, reasonable, practicable, and cost effective. A transcript of the teleconference is available in the docket for this rulemaking. The following tables summarize the major changes discussed at the meeting.

NPRM language	TAC recommendation	Final rule language
Burdensome Plan Documentation Requirements		
§ 192.1015 What records must an operator keep? Except for the performance measures records required in § 192.1007, an operator must maintain, for the useful life of the pipeline, records demonstrating compliance with the requirements of this subpart. At a minimum, an operator must maintain the following records for review during an inspection: (a) A written IM program in accordance with § 192.1005; (b) Documents supporting threat identification; (c) A written procedure for ranking the threats; (d) Documents to support any decision, analysis, or process developed and used to implement and evaluate each element of the IM program; (e) Records identifying changes made to the IM program, or its elements, including a description of the change and the reason it was made; and (f) Records on performance measures. However, an operator must only retain records of performance measures for ten years.	Limit documentation requirements to those in § 192.1005 and § 192.1007 Greatly reduce requirements in § 192.1015; focus on wording similar to § 192.1015(e) Clarify requirement to retain record of past versions of written IM program Language: § 192.1015 What records must an operator keep? (a) General records. Operator must maintain records demonstrating compliance with the requirements of this subpart for 10 years. This must include copies of superseded IM plans.	§ 192.1011 What records must an operator keep? An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. This must include copies of superseded integrity management plans developed under this subpart.
Reporting Plastic Pipe Failures		
§ 192.1009 What must an operator report when plastic pipe fails? Each operator must report information relating to each material failure of plastic pipe (including fittings, couplings, valves and joints) no later than 90 days after failure. This information must include, at a minimum, location of the failure in the system, nominal pipe size, material type, nature of failure including any contribution of local pipeline environment, pipe manufacturer, lot number and date of manufacture, and other information that can be found in markings on the failed pipe. An operator must send the information report as indicated in § 192.1013. An operator must also report this information to the State pipeline safety authority in the State where the gas distribution pipeline is located.	Delete requirement Continue to rely on PPDC Promote broad communication of more expansive set of PPDC lessons Retain reporting of compression couplings failure Language: § 192.1009 What must an operator report when compression couplings fail? Each operator must report information relating to each failure of compression couplings annually by March 15, to PHMSA as part of the annual report required by § 191.11 beginning with the report submitted March 15, 20xx [Date to depend on when final rule is issued].	§ 192.1009 What must an operator report when compression couplings fail? Each operator must report, on an annual basis, information related to failure of compression couplings, excluding those that result only in non-hazardous leaks, as part of the annual report required by § 191.11 beginning with the report submitted March 15, 2011. This information must include, at a minimum, location of the failure in the system, nominal pipe size, material type, nature of failure including any contribution of local pipeline environment, coupling manufacturer, lot number and date of manufacture, and other information that can be found in markings on the failed coupling. An operator also must report this information to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.
Performance Through People		
(b) In considering the threat of inappropriate operation, the operator must evaluate the contribution of human error to risk and the potential role of people in preventing and mitigating the impact of events contributing to risk. This evaluation must also consider the contribution of existing DOT requirements applicable to the operator's system (e.g., Operator Qualification, Drug and Alcohol Testing) in mitigating risk.	Delete requirement, including reference to "one call." Language: (d) Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline system. These measures must include an effective leak management program (unless all leaks are repaired when found) and a damage prevention program required under § 192.614 of this part.	Requirement deleted, including reference to "one call." (d) Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).

NPRM language	TAC recommendation	Final rule language
(d) Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline system. These measures must include implementing an effective leak management program and enhancing the operator's damage prevention program required under § 192.614 of this part. To address risks posed by inappropriate operation, an operator's written IM program must contain a separate section with a heading 'Assuring Individual Performance'. In that section, an operator must list risk management measures to evaluate and manage the contribution of human error and intervention to risk (e.g., changes to the role or expertise of people), and implement measures appropriate to address the risk. In addition, this section of the written IM program must consider existing programs the operator has implemented to comply with § 192.614 (damage prevention programs); § 192.616 (public awareness); Subpart N of this Part (qualification of pipeline personnel), and 49 CFR Part 199 (drug and alcohol testing).	(f) Periodic Evaluation and Improvement. An operator must continually re-evaluate threats and risks on its entire system and consider the relevance of threats in one location to other areas. In addition, each operator must periodically evaluate the effectiveness of its program for assuring individual performance to reassess the contribution of human error to risk and to identify opportunities to intervene to reduce further the human contribution to risk (e.g., improve targeting of damage prevention efforts). Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program reevaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.	(f) Periodic Evaluation and Improvement. An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program reevaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.
Definition of ''Damage''		
Damage means any impact or exposure resulting in the repair or replacement of an underground facility, related appurtenance, or materials supporting the pipeline.	Define ''excavation damage'' building on the definition in DIRT—increases clarity of reporting requirement. Language: Excavation Damage means any impact or exposure that results in the need to repair or replace an underground facility due to the weakening or the partial or complete destruction of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.	Excavation Damage means any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.
Implementation Requirements		
§ 192.1005 What must a gas distribution operator (other than a master meter or LPG operator) do to implement this subpart? (a) Dates. No later than June 6, 2011 an operator of a gas distribution pipeline must develop and fully implement a written IM program. The IM program must contain the elements described in § 192.1007. (b) Procedures. An operator's program must have written procedures describing the processes for developing, implementing and periodically improving each of the required elements.	Retain same period Language: § 192.1005 What must a gas distribution operator (other than a master meter or LPG operator) do to implement this subpart? (a) Dates. No later than June 6, 2011 an operator of a gas distribution pipeline must develop and fully implement a written IM program. The IM program must contain the elements described in § 192.1007. (b) Procedures. An operator's program must have written procedures for developing, implementing and periodically improving the required elements.	§ 192.1005 What must a gas distribution operator (other than a master meter or small LPG operator) do to implement this subpart? No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in § 192.1007.

NPRM language	TAC recommendation	Final rule language
Alternative Intervals for Periodic Actions		
§ 192.1017 When may an operator deviate from required periodic inspections under this part? (a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart. Operators may propose reductions only where they can demonstrate that the reduced frequency will not significantly increase risk. (b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or the State agency responsible for oversight of the operator's system. PHMSA, or the applicable State oversight agency, may accept the proposal, with or without conditions and limitations, on a showing that the adjusted interval provides a satisfactory level of pipeline safety.	Clarify intent as to responsibility for decision on waiver requests (States approve, no PHMSA review) Need to make sure that it is clear that overall level of safety is increased—not the level of safety on that particular line is equal or higher. System level rather than individual line. Language: § 192.1017 When may an operator deviate from required periodic inspections under this part? (a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart. Operators may propose reductions only where they can demonstrate that the reduced frequency will not significantly increase risk. (b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or, in the case of an intrastate pipeline facility regulated by the State, the appropriate State agency. The applicable state oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the adjusted interval provides a satisfactory level of pipeline safety.	§ 192.1013 When may an operator deviate from required periodic inspections under this part? (a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart. (b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or, in the case of an intrastate pipeline facility regulated by the State, the appropriate State agency. The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety. (c) An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

NPRM language	TAC recommendation	Final rule language
Program Requirements for Master Meters and LPG Operators		
(1) Infrastructure knowledge. The operator must demonstrate knowledge of the system's infrastructure, which, to the extent known, should include the approximate location and material of its distribution system. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities. (2) Identify threats. The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment malfunction and inappropriate operation. (3) Identify and implement measures to mitigate risks. The operator must determine and implement measures designed to reduce the risks from failure of its pipeline system. (4) Measure performance, monitor results, and evaluate effectiveness. The operator must develop and monitor performance measures on the number of leaks eliminated or repaired on its pipeline system and their causes. (5) Periodic evaluation and improvement. The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.	Retain separate treatment; revise wording to include the requirement to "rank risks" Language: (1) Infrastructure knowledge. The operator must demonstrate knowledge of the system's infrastructure, which, to the extent known, should include the approximate location and material of its distribution system. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities. (2) Identify threats. The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment malfunction and inappropriate operation. (3) Rank risks. The operator must evaluate the risks to its system and estimate the relative importance of each identified threat. (4) Identify and implement measures to mitigate risks. The operator must determine and implement measures designed to reduce the risks from failure of its pipeline system. (5) Measure performance, monitor results, and evaluate effectiveness. The operator must develop and monitor performance measures on the number of leaks eliminated or repaired on its pipeline system and their causes. (6) Periodic evaluation and improvement. The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.	(1) Knowledge. The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities). (2) Identify threats. The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation. (3) Rank risks. The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat. (4) Identify and implement measures to mitigate risks. The operator must determine and implement measures designed to reduce the risks from failure of its pipeline. (5) Measure performance, monitor results, and evaluate effectiveness. The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes. (6) Periodic evaluation and improvement. The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

NPRM language	TAC recommendation	Final rule language
Excess Flow Valve Requirement		
§ 192.1011 When must an Excess Flow Valve (EFV) be installed? (a) General requirements. This section only applies to new or replaced service lines serving single-family residences. An EFV installation must comply with the requirements in § 192.381. (b) Installation required. The operator must install an EFV on the service line installed or entirely replaced after March 4, 2010, unless one or more of the following conditions is present: (1) The service line does not operate at a pressure of 10 psig or greater throughout the year; (2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence; (3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or (4) An EFV meeting performance requirements in § 192.381 is not commercially available to the operator.	Move provision to Subpart H this will lead to requiring implementation by MM; Explicitly address EFV installation requirement on branch service lines—clarify that EFVs are required for service lines servicing single family residences. Language: § 192.383 Excess flow valve installation. (a) Definitions. As used in this section: Replaced service line means a natural gas service line where the fitting that connects the service line to the main line is replaced or the piping connected to this fitting is replaced. Service line serving single-family residence means a natural gas service line beginning at the fitting that connects the service line to the main and serving only one single-family residence. (b) Installation required. An EFV installation must comply with the performance standards in § 192.381. The operator must install an EFV on new or replaced service lines serving single-family residences after February 2, 2010, unless one or more of the following conditions is present: (1) The service line does not operate at a pressure of 10 psig or greater throughout the year; (2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence; (3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or (4) An EFV meeting performance requirements in § 192.381 is not commercially available to the operator.	§ 192.383 Excess flow valve installation. (a) Definitions. As used in this section: Replaced service line means a natural gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced. Service line serving single-family residence means a natural gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence. (b) Installation required. An excess flow valve (EFV) installation must comply with the performance standards in § 192.381. The operator must install an EFV on any new or replaced service line serving a single-family residence after February 2, 2010, unless one or more of the following conditions is present: (1) The service line does not operate at a pressure of 10 psig or greater throughout the year; (2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence; (3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or (4) An EFV meeting performance standards in § 192.381 is not commercially available to the operator. (c) Reporting. Each operator must, on an annual basis, report the number of EFVs installed pursuant to this section as part of the annual report required by § 191.11.

V. Final Rule

The final rule revises 49 CFR Part 192 to add integrity management requirements applicable to distribution pipelines. This addresses statutory mandates and builds on previous similar requirements established for gas transmission pipelines. The final rule also adds a requirement that operators install excess flow valves (EFV) on all new and replaced residential service lines serving single residences, as required by the PIPES Act.

Section-by-Section Analysis

Section 192.383. Excess flow valve installation

This section currently requires that operators notify new customers of the availability of excess flow valves (EFV) and install a valve if the customer agrees to pay for the installation and any subsequent maintenance costs. This requirement has been superseded by the statutory mandate that PHMSA require operators to install such valves in all new and replaced residential service lines serving single-family residences. This section is revised to replace the notification requirement with the new requirement to install. Installation is not required if operating pressure is less than 10 psig, if the operator has experience with contaminants that would interfere with valve operation, if an EFV is likely to interfere with necessary operation or maintenance activities, or if an EFV meeting the performance standards of § 192.381 is not commercially available. The revised section also requires that each operator report the number of EFVs installed during each year in the annual report already required (§ 192.11).

A definition for ''service line serving single-family residence'' is added.

Subpart P—Gas Distribution Pipeline Integrity Management (IM)

A new subpart P is added that includes all of the new requirements applicable to distribution pipeline integrity management.

Section 192.1001. What definitions apply to this subpart?

This section adds a definition for ''excavation damage,'' which is one of the performance measures that operators must report to PHMSA as part of their annual reports. A common definition for this term is needed to assure consistency in the data collected and thus the ability for PHMSA to analyze the effectiveness of these regulations. The definition is based on the definition of damage used by the Common Ground Alliance for its Damage Information Reporting Tool (DIRT), a voluntary program used by some distribution pipeline operators to collect data on damages to underground facilities.

A definition of the term ''hazardous leak'' is added. The new rule will require operators to report annually the number of hazardous leaks repaired. Commenters have correctly noted that a consistent definition will be important to assuring that this data is useful. Several comments suggested that PHMSA adopt the Gas Piping Technology Committee's (GPTC) Guide definition for a Grade 1 leak. This definition is already used by many operators to define hazardous leaks. PHMSA has followed the suggestion of the comments. The change to this section adds a definition similar to that of the GPTC Guide for Grade 1 leaks.

A definition for ''integrity management program'' is added. An integrity management program, as used within this rule, is an overall approach by an operator to ensure the integrity of its distribution system. The program includes an integrity management plan, which is revised periodically. The program also encompasses compliance with other relevant regulations. For some operators, the program may involve the selection of certain materials or adherence to professional standards that are not mandated by Federal regulation.

A definition for ''integrity management plan'' is added. An integrity management plan is a written explanation of the mechanisms the operator will use to implement its integrity management program and to ensure compliance with this rule.

A definition for ''small LPG operators'' is added. The new rule requires LPG operators with LPG distribution systems serving 100 or more customers to comply with the full integrity management program requirements. Small LPG operators, those with LPG distribution systems serving less than 100 customers from a single source must comply with the same requirements as master meter operators.

Section 192.1003. What do the regulations in this subpart cover?

This section describes the content of the new subpart and specifies which operators must comply with which sections. Master meter operators and small LPG operators are not required to meet all of the requirements applicable to other operators of distribution pipelines. The content of IM programs required of these operators is similar (described below), but somewhat simpler. Documentation requirements for these operators are different, consistent with their treatment in the rest of Part 192.

Section 192.1005. What must a gas distribution operator (other than a master meter or small LPG operator) do to implement this subpart?

This section requires operators of gas distribution pipelines and of LPG distribution pipelines serving 100 or more customers from a single source to develop and implement an IM program no later than 18 months after the effective date of this final rule. PHMSA recognizes that IM programs are likely to improve as operators gain experience. This does not mean, however, that it is acceptable for programs developed and implemented within 18 months to be incomplete. Those programs should address all required elements. PHMSA expects operators to revise their plans, following initial implementation, to reflect lessons that they learn through implementing them.

Section 192.1007. What are the required elements of an integrity management (IM) plan?

This section defines the minimum elements that IM plans developed by distribution pipeline operators (other than master meter and small LPG operators) must address. A plan must have written procedures for developing and implementing the following elements:

a. Knowledge. This section requires an operator to develop an understanding of its distribution pipeline. An operator must identify the characteristics of its pipeline's design and operations, and of the environment in which it operates, which are necessary to assess applicable threats and risks. This must include considering information gained from past design, operations, and maintenance.

This section requires that operators develop their understanding from reasonably available information. The rule does not require operators to retrieve many years of archived records or to conduct additional investigations (e.g., excavation) to discover information about the pipeline. Operators have considerable knowledge of their pipeline to support routine operations and maintenance, but this information may be distributed throughout the company, in possession of groups responsible for individual functions. Operators must assemble this information to the extent necessary to support development and implementation of their IM program.

PHMSA recognizes that there may be gaps in the knowledge an operator has when it develops its initial IM plan. Operators must identify these gaps and the additional information needed to improve their understanding. Operators are required to provide a plan for gaining that information over time through its normal activities of operating and maintaining their pipeline (*e.g.,* collecting information about buried components when portions of the pipeline must be excavated for other reasons). Operators must also develop a process by which the program will be periodically reviewed and refined, as needed.

b. Identify threats. Identification of the threats that affect, or could potentially affect, a distribution pipeline is key to assuring its integrity. Knowledge of applicable threats allows operators to evaluate the risks they pose and to rank those risks, allowing safety resources to be applied where they will be most effective.

This section requires that operators consider the general categories of threats that must now be reported on annual reports. Reporting has been required for many years, meaning that data are available regarding these threat categories. Operators are required to consider reasonably available information to identify threats that affect their pipeline or that could potentially affect it (*e.g.,* landslides in a hilly area with loose soils even if no landslide has been experienced). The section specifies data sources resulting from normal operation and maintenance that operators may consider in evaluating threats.

c. Evaluate and rank risk. This section requires that an operator evaluate the identified threats to determine their relative importance and rank the risks associated with its pipeline. Operators must consider the likelihood of threats as well as the consequences of a failure that might result from each threat. Consideration of consequences is important to assure that risks are properly ranked. A potential accident of relatively low likelihood but that would produce significant consequences may be a higher risk than an accident with somewhat greater likelihood but that cannot produce major consequences.

Operators may subdivide their pipeline into regions for purposes of this analysis. Such division may be appropriate when factors relevant to a threat vary within the pipeline. For example, the threat of corrosion is not applicable to portions of the pipeline made of plastic materials. The corrosion threat likely would be of different importance to metal portions of the pipeline that are coated and cathodically protected than it would be to any portions that are bare or unprotected. Operators are not, however, required to divide their pipelines for purposes of analyzing risks.

d. Identify and implement measures to address risks. Operator IM programs must include measures designed to reduce the risk of failure from identified threats. These measures must include an effective leak management program (which most operators are already implementing) unless the operator already repairs all leaks when found.

e. Measure performance, monitor results, and evaluate effectiveness. Measuring performance is a key element of IM programs. This section requires operators to develop performance measures, including some that are specified for use by all operators. Measuring performance periodically allows operators to determine whether actions being taken to address threats are effective, or whether different or additional actions are needed.

f. Periodic Evaluation and Improvement. This element requires operators to periodically re-evaluate risks on their entire pipeline and to consider the relevance of threats in one location to other locations. Operators must consider the results of their performance monitoring in these evaluations, which must be performed at least once every five years. An operator must determine an appropriate period for conducting a complete program evaluation based on the complexity of its system. An operator should conduct a program evaluation any time there are changes in factors that would affect the risk of failure.

g. Report results. This section requires that operators include in their annual reports some of the performance measures required by the rule. PHMSA will use this data to evaluate the overall effectiveness of distribution IM requirements. (Note that one of the measures required to be reported—all leaks repaired, by cause—has historically been required on the annual report).

Section 192.1009. What must an operator report when compression couplings fail?

Compression couplings are mechanical fittings used to connect sections of pipe. Such couplings are often used to connect plastic pipe to metal pipe. Failure of compression couplings has resulted in a number of serious accidents on distribution pipelines. This section requires that operators report information related to failure of compression couplings (excluding failures that result only in non-hazardous leaks) on their annual report. PHMSA will use this data to evaluate the scope of problems related to compression couplings and will determine if changes to the regulations are appropriate to help prevent incidents caused by coupling failure.

Section 192.1011. What records must an operator keep?

This section requires that operators keep records for 10 years that demonstrate compliance with the requirements of this new subpart. The records must include superseded copies of IM plans.

Section 192.1013. When may an operator deviate from required periodic inspections under this part?

The operator's evaluation of threats and risk may identify additional actions that could be effective in reducing risk on distribution pipelines. This section allows operators to reduce the frequency of actions now required by this Part to be conducted periodically, to realign safety resources to better address risks. Operators must receive approval from their safety regulator (PHMSA or state, as appropriate) before they can reduce the required frequency, and must demonstrate that the overall effect of their proposed change will be an equal or greater level of pipeline safety.

This section requires an operator to submit a proposal that explains the desired alternative frequency for a required periodic inspection and that explains other actions the operator will take as part of the integrity management program to ensure an equal or greater overall level of pipeline safety. A proposal should include sufficient information to explain how the IM plan and IM program would be modified if the proposal is approved. States will use their authority to approve reductions in the frequency of safety actions otherwise required by Part 192.

Section 192.1015. What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?

Most master meter operators are small entities and operating their gas distribution pipelines is not their principal occupation. These operators typically have limited on-staff technical pipeline expertise. These operators have historically been treated differently within Part 192. In particular, they have been subject to more limited documentation requirements. For example, master meter operators and operators of LPG distribution pipelines that serve fewer than 100 customers from a single source are not required to submit annual reports.

This section prescribes IM requirements applicable to these smaller operators. The major elements that these operators are required to include in their IM plans are the same as those in § 192.1007 applicable to other operators. The details of the elements are simplified somewhat, to reflect both the relative simplicity of these pipelines and the limited capability of the operators. For example, the required knowledge of their pipeline is focused on the approximate location and material of which it is constructed and required documentation of this knowledge is limited to documents showing the location and material of piping and appurtenances that are installed after the effective date of their IM programs and, to the extent known, in existence when the program becomes effective. These operators are not required to submit performance measures, which is consistent with their prior treatment with respect to annual reports.

PHMSA expects that the IM plans developed by these operators will be simpler than those developed by operators of more complex distribution pipelines. PHMSA is developing guidance suitable for use by master meter and small LPG operators to develop simple IM plans for their pipelines. This guidance will be made available via PHMSA's web site after this final rule is published.

VI. Regulatory Analyses and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the authority of the Federal Pipeline Safety Law (49 U.S.C. 60101 *et seq.*). Section 60102 authorizes the Secretary of Transportation to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. The integrity management program regulations are issued under this authority and address NTSB and DOT Inspector General recommendations. This rulemaking also carries out the mandates regarding distribution integrity management and excess flows valves under section 9 of the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (Pub. L. No. 109–468, Dec. 29, 2006, codified at 49 U.S.C. § 60109(e)).

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

Executive Order 12866 directs all Federal agencies to consider the costs and benefits of ''significant regulatory actions.'' Federal agencies are directed to develop a formal Regulatory Impact Analysis consistent with OMB Circular A–4 for all ''economically significant'' rules, or those rules estimated to have an impact of $100 million or more in any one year.

DOT considers this an ''economically significant'' regulatory action under section 3(f)(1) of Executive Order 12866 (58 FR 51735; October 4, 1993). This final rule is also significant under DOT's regulatory policies and procedures (44 FR 11034; February 26, 1979). PHMSA prepared a Regulatory Evaluation for this final rule and placed it in the public docket.

The rule's requirements would affect an estimated 9,343 natural gas operators with a combined total of 1,138,000 miles of mains and 60,970,000 services. Of these operators, 201 are large local gas utilities, 1,090 are small local gas utilities, 52 are LPG operators servicing 100 or more customers from a single source, and approximately 8,000 are master meter and small LPG systems. PHMSA determined that the approximately 1,142 gas operators and the 8,000 master meter operators and LPG systems are small.

The monetized benefits resulting from the final rule are estimated to be between $165 million and $170 million per year. Those benefits include:

- Reductions in the consequences of reportable incidents
- Reductions in the consequences of non-reportable incidents
- A reduction in the probability of a major catastrophic incident
- Reductions in lost natural gas
- Reductions in emergency response costs
- Reductions in evacuations
- Reductions in dig-ins impacting non-gas underground facilities
- The end of the existing EFV notification requirement

The costs of the final rule are estimated to be $130 million in the first year and $101 million in each subsequent year. Those costs cover:

- Development of an IM program
- Implementation of the IM program (data acquisition and analysis)
- Mitigation of risks (leak management, excess flow valve installation and other)
- Reporting to PHMSA and State Regulators
- Recordkeeping
- Management of the IM program.

The Regulatory Impact Analyses (RIA) finds that the rule is not expected to adversely affect the economy or the environment. The analysis finds that, for those costs and benefits that can be quantified, the present value of net benefits is expected to be between $21 million and $1.6 billion over a 50-year period after all of the requirements are implemented. Furthermore, the rule is expected yield positive net benefits if it results in eliminating only approximately 12.2 percent of the societal costs the first year, and about 9.5 percent in subsequent years.

C. Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), PHMSA must consider whether a rulemaking would have a significant effect on a substantial number of small entities. The IM program requirements in this rule apply to gas distribution pipeline operators and require operators of gas distribution pipelines to develop and implement IM plans that will better assure the integrity of their pipeline systems.

Many gas distribution pipeline operators meet the Small Business Administration's small business definition of 500 or fewer employees for natural gas distribution operators under North American Industry Classification System (NAICS) 221210. PHMSA estimates that the rule will affect approximately 9,090 small operators. These small operators can be separated into two categories: (1) Local gas distribution utilities with 12,000 or fewer services and (2) master meter and LPG systems. PHMSA estimates there are 1,090 small operators among the local gas distribution utilities with 12,000 or fewer services and approximately 8,000 master meter and LPG systems, all of which are small.

Furthermore, PHMSA estimates the rule will cost each of the 1,090 small operators and the 52 LPG operators serving 100 or more customers from a single source, on average, approximately $33,600 in the first year and $15,400 in each subsequent year. PHMSA also estimates that the rule will cost each of the 8,000 master meter and small LPG systems, on average, approximately $2,900 in the first year and $1,100 in each subsequent year. PHMSA does not have information on the operators' revenues and cannot estimate the economic impact the costs will have. The costs associated with the rule may be significant for at least some of the small entities, if the costs exceed 1 percent of the revenues. Therefore, PHMSA believes that the rule could result in a significant adverse economic impact for some of the smallest affected entities.

PHMSA has minimized costs for these small operators. As mentioned earlier, small operators' IM programs will be subject to more limited documentation requirements. PHMSA is also providing guidance for small operators. Additionally, industry is undertaking a number of initiatives that will help small entities comply with the proposed rule, including the preparation of guidance materials and a model IM program for distribution pipeline operators.

D. Paperwork Reduction Act

The Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) addresses the collection of information by the Federal government from individuals, small businesses and state and local governments and seeks to minimize the burdens such information collection requirements might impose. A collection of information includes providing answers to identical questions posed to, or identical reporting or record-keeping requirements imposed on ten or more persons, other than agencies, instrumentalities, or employees of the United States. In accordance with the requirements of the Paperwork Reduction Act, agencies may not conduct or sponsor, and the respondent is not required to respond to, an information collection unless it displays a currently valid Office of Management and Budget (OMB) control number.

This rule requires operators to report four distribution integrity management program (DIMP) performance measures in the annual report (Incident and Annual Reports for Gas Pipeline Operators. OMB Control Number: 2137–0522). All data required under this rule to be reported will be reported via the annual report.

One of the measures required to be reported—all leaks repaired, by cause—has historically been required as part of annual reports. The other information to be reported will require modifications to the annual report form. Therefore, PHMSA is also using this rulemaking as a 60-day notice to revise the annual report information collection, OMB Control Number 2137–0522. PHMSA seeks comment on the proposed modified annual report form, which is available in the docket for this rulemaking.

In addition, the rule also requires operators to report, as part of the annual report, detailed information regarding compression coupling failures. PHMSA has created a compression coupling failure addendum to be submitted with the annual report form, as needed. PHMSA also seeks comment on the proposed compression coupling failure addendum form. This form will also be part of the revised 2137–0522 information collection and is available in the docket for this rulemaking.

PHMSA estimates that the additional average time required for completing the annual report, beyond the time that gas distribution operators are already expending, is 6 hours per year per operator. This results in a burden increase of 8,058 hours per year for all 1,343 operators that have to comply with the annual report requirements. The required information can be reported electronically. Operators are permitted to keep records in any retrievable form. They may use the latest information technology to reduce the additional information-collection burden.

In addition to the reporting requirements, this final rule requires each affected operator to develop and maintain a written integrity management plan, which includes initial plan development, recordkeeping and updates. These non-reporting requirements are covered by Integrity Management Program for Gas Distribution Pipelines, OMB Control Number: 2137–0625. OMB assigned Control Number 2137–0625 to the information collection but withheld approval pending publication of this Final Rule, which addresses comments to the Notice. This Final Rule serves as a 30-day notice for the information collection, and PHMSA will forward an information collection package for OMB review concurrent with publication of this final rule.

Each operator, other than master meter operators and small LPG operators, must also collect and record one other specified performance measure and any other performance measures unique to the operator's pipeline that are needed to evaluate the effectiveness of the integrity management program. PHMSA estimates these tasks will require an additional 2,289 hours for all 9,343 operators. An explanation of all burden hour estimates is contained in the Paperwork Reduction Act Supporting Statement and the Regulatory Impact Analysis (RIA) available in the docket for this rulemaking.

E. Executive Order 13084

This final rule has been analyzed under principles and criteria contained in Executive Order 13084 (''Consultation and Coordination with Indian Tribal Governments''). Because this rule does not significantly or uniquely affect communities of Indian tribal governments and does not impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13084 do not apply.

F. Executive Order 13132

PHMSA analyzed this final rule under the principles and criteria contained in Executive Order 13132 (Federalism). PHMSA issues pipeline safety regulations applicable to interstate and intrastate pipelines. The requirements in this rule apply to operators of distribution pipeline systems, primarily intrastate pipeline systems. Under 49 U.S.C. 60105, PHMSA cedes authority to enforce safety standards on intrastate pipeline facilities to a certified state authority. Thus, state pipeline safety regulatory agencies will be the primary enforcer of these safety requirements. Although some states have additional requirements that address IM issues, no state requires its distribution operators to have comprehensive IM programs similar to that required by this rule. Under 49 U.S.C. 60107, PHMSA provides grant money to participating states to carry out their pipeline safety enforcement programs. Although some states choose not to participate in the pipeline safety grant program, every state has the option to participate. This grant money is used to defray added safety program costs incurred by enforcing the requirements. We expect to increase money available to help states.

PHMSA has concluded this rule does not include any regulation that: (1) Has substantial direct effects on states, relationships between the national government and the states, or distribution of power and responsibilities among various levels of government; (2) imposes substantial direct compliance costs on states and local governments; or (3) preempts state law. Therefore, the consultation and funding requirements of Executive Order 13132 (64 FR 43255; August 10, 1999) do not apply.

This rule preempts any currently established state requirements in this area. States have the ability to augment pipeline safety requirements for pipelines, but are not able to approve safety requirements less stringent than those contained within this rule.

Although the consultation requirements do not apply, the states have played an integral role in helping develop these requirements. State pipeline safety regulatory agencies participated in the stakeholder groups that helped develop the findings on which this rule is based and provided guidance through NARUC in the form of a resolution. PHMSA action is consistent with this resolution.

G. Executive Order 13211

This final rule is not a ''significant energy action'' under Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use). It is not likely to have a significant adverse effect on supply, distribution, or energy use. Further, the Office of Information and Regulatory Affairs has not designated this rule as a significant energy action.

H. Unfunded Mandates

PHMSA estimates that this final rule does impose an unfunded mandate under the 1995 Unfunded Mandates Reform Act (UMRA). PHMSA estimates the rule to cost operators $155.1 million in the first year of the regulations, which is higher than the $100 million threshold (adjusted for inflation, currently estimated to be $141.3 million) in any one year. The Regulatory Impact Analysis performed under EO 12866 requirements also meets the analytical requirements under UMRA, and PHMSA has concluded the approach taken in this regulation is the least burdensome alternative for achieving our rule's objectives.

I. National Environmental Policy Act

PHMSA analyzed this final rule in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR 1500–1508), and DOT Order 5610.1C, and has determined that this action will not significantly affect the quality of the human environment. PHMSA conducted an Environmental Assessment on the NPRM and did not receive any comment on the preliminary analysis. The Environmental Assessment is available for review in the Docket.

List of Subjects in 49 CFR Part 192

Integrity management, Pipeline safety, Reporting and recordkeeping requirements.

■ In consideration of the foregoing, PHMSA is amending Part 192 of Title 49 of the Code of Federal Regulations as follows:

PART 192 TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 1. The authority citation for part 192 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116, 60118, and 60137; and 49 CFR 1.53.

■ 2. Section 192.383 is revised to read as follows:

§ 192.383 Excess flow valve installation.

■ (a) Definitions. As used in this section:

Replaced service line means a natural gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

Service line serving single-family residence means a natural gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence.

(b) *Installation required.* An excess flow valve (EFV) installation must comply with the performance standards in § 192.381. The operator must install an EFV on any new or replaced service line serving a single-family residence after February 2, 2010, unless one or more of the following conditions is present:

(1) The service line does not operate at a pressure of 10 psig or greater throughout the year;

(2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence;

(3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or

(4) An EFV meeting performance standards in § 192.381 is not commercially available to the operator.

(c) *Reporting.* Each operator must, on an annual basis, report the number of EFVs installed pursuant to this section as part of the annual report required by § 191.11.

■ 3. In Part 192, a new subpart P is added to read as follows:

Subpart P—Gas Distribution Pipeline Integrity Management (IM)

Sec.

Subpart P—Gas Distribution Pipeline Integrity Management (IM)

§ 192.1001 What definitions apply to this subpart?

The following definitions apply to this subpart:

Excavation Damage means any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.

Hazardous Leak means a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

Integrity Management Plan or *IM Plan* means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart.

Integrity Management Program or *IM Program* means an overall approach by an operator to ensure the integrity of its gas distribution system.

Small LPG Operator means an operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

§ 192.1003 What do the regulations in this subpart cover?

General. This subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator, other than a master meter operator or a small LPG operator, must follow the requirements in §§ 192.1005–192.1013 of this subpart. A master meter operator or small LPG operator of a gas distribution pipeline must follow the requirements in § 192.1015 of this subpart.

§ 192.1005 What must a gas distribution operator (other than a master meter or small LPG operator) do to implement this subpart?

No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in § 192.1007.

§ 192.1007 What are the required elements of an integrity management plan?

A written integrity management plan must contain procedures for developing and implementing the following elements:

(a) *Knowledge.* An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(1) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.

(2) Consider the information gained from past design, operations, and maintenance.

(3) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

(4) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.

(5) Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.

(b) *Identify threats.* The operator must consider the following categories of threats to each gas distribution pipeline: Corrosion, natural forces, excavation damage, other outside force damage, material, weld or joint failure (including compression coupling), equipment failure, incorrect operation, and other concerns that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(c) *Evaluate and rank risk.* An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

(d) *Identify and implement measures to address risks.* Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).

(e) *Measure performance, monitor results, and evaluate effectiveness.*

(1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(i) Number of hazardous leaks either eliminated or repaired as required by § 192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause;

(ii) Number of excavation damages;

(iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(iv) Total number of leaks either eliminated or repaired, categorized by cause;

(v) Number of hazardous leaks either eliminated or repaired as required by § 192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material; and

(vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.

(f) *Periodic Evaluation and Improvement.* An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(g) *Report results.* Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, as part of the annual report required by § 191.11. An operator also must report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

§ 192.1009 What must an operator report when compression couplings fail?

Each operator must report, on an annual basis, information related to failure of compression couplings, excluding those that result only in non-hazardous leaks, as part of the annual report required by § 191.11 beginning with the report submitted March 15, 2011. This information must include, at a minimum, location of the failure in the system, nominal pipe size, material type, nature of failure including any contribution of local pipeline environment, coupling manufacturer, lot number and date of manufacture, and other information that can be found in markings on the failed coupling. An operator also must report this information to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

§ 192.1011 What records must an operator keep?

An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.

§ 192.1013 When may an operator deviate from required periodic inspections under this part?

(a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart.

(b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or, in the case of an intrastate pipeline facility regulated by the State, the appropriate State agency. The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.

(c) An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

§ 192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?

(a) *General.* No later than August 2, 2011 the operator of a master meter system or a small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph (b) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

(b) *Elements.* A written integrity management plan must address, at a minimum, the following elements:

(1) *Knowledge.* The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

(2) *Identify threats.* The operator must consider, at minimum, the following categories of threats (existing and potential): Corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.

(3) *Rank risks.* The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.

(4) *Identify and implement measures to mitigate risks.* The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.

(5) *Measure performance, monitor results, and evaluate effectiveness.* The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.

(6) *Periodic evaluation and improvement.* The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(c) *Records.* The operator must maintain, for a period of at least 10 years, the following records:

(1) A written IM plan in accordance with this section, including superseded IM plans;

(2) Documents supporting threat identification; and

(3) Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and

appurtenances that were existing on the effective date of the operator's program.

Issued in Washington, DC on November 20, 2009 under Authority delegated in Part 1.

Cynthia L. Quarterman,

Administrator.

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